

# **Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review**

**Response to Public Comments on the November 2021 Proposed Rule and the December  
2022 Supplemental Proposed Rule**

**86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022**

U.S. Environmental Protection Agency  
Office of Air and Radiation  
Office of Air Quality Planning and Standards  
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## Foreword

This document provides responses to public comments received on the U.S. Environmental Protection Agency (EPA) “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review” proposals. Specifically, this document includes EPA’s responses to public comments received on the November 2021 Proposed Rule (86 FR 63110, November 15, 2021) and the December 2022 Supplemental Proposed Rule (87 FR 74702, December 6, 2022); hereinafter referred to as the November 2021 Proposal and the December 2022 Supplemental Proposal, respectively.

EPA received comments on these proposals via regulations.gov, mail, email, and during virtual public hearings. Hardcopies of all comments submitted are available at the EPA Docket Center Public Reading Room. Comments letters and transcripts of the virtual public hearings are also available electronically at <http://www.regulations.gov> by searching Docket ID No. EPA-HQ-OAR-2021-0317.

The high-level structure of this document includes this Foreword and a list of common acronyms and abbreviations used throughout the document; Volumes I and II (with individual Table of Contents); and Appendices that combined present a summary of comments received and EPA’s responses to those comments.

Volumes I and II of this document include the following:

- Volume I: *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Response to Public Comments on the November 2021 Proposed Rule* (86 FR 63110, November 15, 2021).
- Volume II: *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Response to Public Comments on the November 2021 Proposed Rule and the December 2022 Supplemental Proposed Rule* (87 FR 74702, December 6, 2022).

Each of the volumes consists of a separate table of contents and an introduction presenting a high-level summary of the comments received on the applicable proposal. For links to Volumes I and II and Appendices, click below:

- [Volume I](#)
- [Volume II](#)
- [Appendices](#)

In addition, each volume includes several sections, with each section focusing on a different broad category of comments on the rule. Considering the large number of comments received on the proposals and the significant overlap between many comments, this document does not respond to each comment individually. Rather, EPA summarized and provided a single response to each significant argument, assertion, and question contained within the totality of comments.

Within each comment summary, EPA provides in parenthesis one or more lists of Docket ID Numbers (DCN(s)) for commenters who raised issues; however, these lists are not meant to be exhaustive, and EPA does not individually identify each commenter who made a certain point in all instances, particularly in cases where multiple commenters expressed essentially identical arguments. Note that the numbers provided in parenthesis reflect the last 4 digits of the DCN. For example, for this docket, the listed ID would be “xxxx” of EPA-HQ-OAR-2021-0317-xxxx.

EPA’s responses to comments are generally provided immediately following each comment summary. In some cases, EPA provided responses to specific comments or groups of similar comments in the preamble to the November 2021 Proposal (86 FR 63110, November 15, 2021 ), the December 2022 Supplemental Proposal (87 FR 74702, December 6, 2022), or the final rulemaking preamble. Similarly, there are some cases where responses refer the reader to another comment response within the document. Comment responses have individual IDs. For responses to comments presented in the Volume I and II Chapters, response IDs reflect the Volume number, Chapter number (or “A” for Appendix), and response number in chronological order presented in the Chapter. For example, “Response I-2-1” would be Volume I, Chapter 2, first response. For responses to comments presented in Appendix A – comment response IDs reflect that the response is in the Appendix by using and “A” prefix, the section number, and the response number in chronological order presented in the Appendix. For example, “Response A-1-3”, would be Appendix A, Section 1, third response. There is only one Appendix (Appendix A) to this Response to Comment (RTC) document that includes comments and responses. We also include abbreviated commenter identifiers after the individual IDs (i.e., XXXX-abbreviated identifier).

In many instances, responses presented in this RTC document also include cross-references to responses on similar or related issues located in the Regulatory Impacts Analysis (RIA) for the final rule and the Technical Support Document (TSD) for the final rule. Accordingly, this RTC document, together with the preamble to the final rule, the RIA for the final rule, the TSD for the final rule, and the rest of the administrative record should be considered collectively as the agency’s response to all the significant comments submitted on the proposed rules.

Comments were assigned to specific sections of this document based on an assessment of the principal subject of the comment; however, some comments inevitably overlap multiple subject areas. It is possible some responses in this RTC document may not reflect the language in the preamble and final rule in every respect. Where the response conflicts with the preamble or the final rule, the language in the final preamble and final rule should be used for purposes of understanding the scope, requirements, and basis of the final rule. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to responses, the preamble itself is the definitive statement of the agency’s rationale for the final rule. To the extent a response in this document could be construed as in conflict with the preamble or the final rule, the language in the final rule preamble and regulatory text supersedes what is included in this document and should be used for purposes of understanding the scope, requirements, and basis of the final rule.



## **Acronyms and Abbreviations**

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                         |
|-----------------------|---------------------------------------------------|
| ACE                   | Affordable Clean Energy                           |
| ACS                   | American Community Survey                         |
| ACT                   | Atmospheric Carbon and Transport                  |
| ADED                  | Advancing Development of Emissions Detection      |
| AERMOD                | AMS/EPA Regulatory Model                          |
| AERR                  | Air Emissions Reporting Requirements              |
| AFRC                  | American Flame Research Committee                 |
| AGM                   | Absorbent Glass Mat                               |
| AGU                   | American Geophysical Union                        |
| AI                    | Artificial Intelligence                           |
| AI                    | American Indian                                   |
| AIMM                  | Approved Instrument Monitoring Method             |
| ALL                   | Acute Lymphocytic Leukemia                        |
| Alt-AIMM              | Alternative Approved Instrument Monitoring Method |
| AMEL                  | Alternative Means of Emission Limitations         |
| AMLD                  | Advanced Mobile Leak Detection                    |
| AMO                   | Atomic, Molecular, And Optical                    |
| AMT                   | Advanced Measurement Techniques                   |
| AN                    | Alaska Native                                     |
| ANPR, ANPRM           | Advance Notice of Proposed Rulemaking             |
| ANS                   | Alaskan North Slope                               |
| AOGCC                 | Alaska Oil and Gas Conservation Commission        |
| AOGI                  | Aerial OGI                                        |
| AOGW                  | Abandoned Oil and Gas Wellheads                   |
| APA                   | Administrative Procedure Act                      |
| APCD                  | Air Pollution Control Division                    |
| APEN                  | Air Pollutant Emission Notice                     |
| AQCC                  | Air Quality Control Commission                    |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                      |
|-----------------------|----------------------------------------------------------------|
| AQD                   | Air Quality Division                                           |
| ARPA-E                | Department of Energy’s Advanced Research Program Agency-Energy |
| ASTECH                | Alberta Science and Technology Award                           |
| ASTM                  | American Society for Testing and Materials                     |
| AVO                   | Auditory, Visual, and Olfactory                                |
| AWMA                  | Air And Waste Management Association                           |
| AWP                   | Alternative Work Practice                                      |
| BACT                  | Best Available Current Technology                              |
| BART                  | Best Available Retrofit Technology                             |
| BBL                   | Barrel of Oil                                                  |
| BCF                   | Billions of Cubic Feet                                         |
| BDL                   | Below Detection Limit                                          |
| BIPOC                 | Black, Indigenous, and People of Color                         |
| BLM                   | Bureau of Land Management                                      |
| BMP                   | Best Management Practices                                      |
| BOE                   | Barrel of Oil Equivalent                                       |
| BOED, BOEPD           | Barrels of Oil Equivalent Per Day                              |
| BSER                  | Best System of Emission Reduction                              |
| BTEX                  | Benzene, Toluene Ethylbenzene, and Xylene                      |
| BU                    | Bottom Up                                                      |
| CA                    | California                                                     |
| CAA                   | Clean Air Act                                                  |
| CAM                   | Compliance Assurance Monitoring                                |
| CAP                   | Criteria Air Pollutant                                         |
| CARB                  | California Air Resources Board                                 |
| CATF                  | Clean Air Task Force                                           |
| CBI                   | Confidential Business Information                              |
| CBM                   | Coal Bed Methane                                               |
| CBPR                  | Community-Based Participatory Research                         |
| CCAC                  | Climate and Clean Air Coalition                                |

| <b><u>Acronym</u></b>                 | <b><u>Description</u></b>                                             |
|---------------------------------------|-----------------------------------------------------------------------|
| CCR                                   | Coal Combustion Residuals                                             |
| CCUS                                  | Carbon Capture, Utilization and Storage                               |
| CDC                                   | Centers For Disease Control and Prevention                            |
| CDPHE                                 | Colorado Department of Health and Environment                         |
| CE                                    | Cost Effectiveness                                                    |
| CE                                    | Combustion Efficiency                                                 |
| CEA                                   | Council of Economic Advisers                                          |
| CEDRI                                 | Compliance and Emissions Data Reporting Interface                     |
| CEMC                                  | Continuous Emission Monitoring System                                 |
| CEN                                   | European Committee for Standardization                                |
| CEQ                                   | Council on Environmental Quality                                      |
| CERCLA                                | Comprehensive Environmental Response, Compensation, and Liability Act |
| CERR                                  | Consolidated Emissions Reporting Requirements                         |
| Cfm                                   | Cubic Foot Per Minute                                                 |
| CFR                                   | Code of Federal Regulations                                           |
| CH <sub>4</sub>                       | Methane                                                               |
| CHD                                   | Coronary Heart Disease                                                |
| CIP                                   | Chemical Injection Pump                                               |
| CM                                    | Continuous Monitors                                                   |
| CMAQ                                  | Community Microscale Air Quality                                      |
| CMS                                   | Continuous Monitoring Systems                                         |
| CNG                                   | Compressed Natural Gas                                                |
| CO                                    | Carbon Monoxide                                                       |
| CO <sub>2</sub>                       | Carbon Dioxide                                                        |
| CO <sub>2</sub> e, CO <sub>2</sub> -e | Carbon Dioxide-Equivalent                                             |
| COGCC                                 | Colorado Oil and Gas Conservation Commission                          |
| C-OGI                                 | Continuous OGI Monitors                                               |
| COP                                   | Conference of the Parties                                             |
| COPD                                  | Chronic Obstructive Pulmonary Disease                                 |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                                  |
|-----------------------|----------------------------------------------------------------------------|
| COVID, COVID-19       | Coronavirus Disease of 2019                                                |
| CPF                   | Centralized Production Facility                                            |
| CPP                   | Clean Power Plan                                                           |
| CRA                   | Congressional Review Act                                                   |
| CSA                   | Controlled Substances Act                                                  |
| CSAPR                 | Cross-State Air Pollution Rule                                             |
| CSCC                  | Country-Level Social Cost of Carbon                                        |
| CTG                   | Control Techniques Guidelines                                              |
| CTM                   | “Conditionally” Approving Test Methods                                     |
| CVD                   | Chemical Vapor Deposition                                                  |
| CVS                   | Closed Vent Systems                                                        |
| cyl                   | Cylinder                                                                   |
| DC                    | Direct Current                                                             |
| D.C. Circuit          | U.S. Court of Appeals for the District of Columbia Circuit                 |
| DEC                   | Department Of Environmental Conservation                                   |
| DFM                   | Digital Flare Mitigation System                                            |
| DICE                  | Dynamic Integrated Climate-Economy Model                                   |
| DOE                   | Department of Energy                                                       |
| DOI                   | Department of Interior                                                     |
| DOJ                   | Department of Energy                                                       |
| DOR                   | Delay of Repair                                                            |
| DOT                   | Department of Transportation                                               |
| DRE                   | Destruction Removal Efficiency                                             |
| e.g.                  | Example                                                                    |
| EAV                   | Equivalent Annual Value                                                    |
| ECCE                  | Environment and Climate Change Canada                                      |
| ECD                   | Enclosed Combustion Device                                                 |
| ECHO                  | Enforcement and Compliance History Online                                  |
| ECOS                  | Environmental Council of States Interstate Technology & Regulatory Council |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                           |
|-----------------------|-----------------------------------------------------|
| ECS                   | Equilibrium Climate Sensitivity                     |
| EE                    | Emissions Events                                    |
| EEMDL                 | Energy Emissions Modeling and Data Lab              |
| EG                    | Emissions Guidelines                                |
| EGU                   | Electric Generating Units                           |
| EIA                   | Energy Information Administration                   |
| EIS                   | Environmental Impact Statement                      |
| EJ                    | Environmental Justice                               |
| EMC                   | Air Emission Measurement Center                     |
| EN                    | European Standard                                   |
| EO                    | Executive Order                                     |
| EOR                   | Enhanced Oil Recovery                               |
| EORI                  | Enhanced Oil Recovery Institute                     |
| EPA                   | Environmental Protection Agency                     |
| EPCA                  | Energy Policy and Conservation Act                  |
| EPCRA                 | Emergency Planning and Community Right to Know Act  |
| EPOD                  | Engineered Power on Demand                          |
| ESCAPE                | European Study of Cohorts for Air Pollution Effects |
| ESD                   | Emergency Shutdown Devices                          |
| ESG                   | Environmental, Social, and Governance               |
| ESPS                  | Existing Source Performance Standards               |
| EU                    | European Union                                      |
| EUR                   | Estimated Ultimate Recovery                         |
| FAIR                  | Finite Amplitude Impulse Response                   |
| FAQ                   | Frequently Asked Questions                          |
| FCE                   | Full Compliance Evaluations                         |
| FDCA                  | Food, Drug, and Cosmetic Act                        |
| FEAST                 | Fugitive Emissions Abatement Simulation Toolkit     |
| FEM                   | Fugitive Emissions Monitoring                       |
| FERC                  | Federal Energy Regulatory Commission                |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                       |
|-----------------------|-----------------------------------------------------------------|
| FIP                   | Federal Implementation Plan                                     |
| FLIR                  | Forward Looking Infrared                                        |
| FOV                   | Field of View                                                   |
| FPIC                  | Free, Prior, and Informed Consent                               |
| fpm                   | Feet Per Minute                                                 |
| FR                    | Federal Register                                                |
| FRA                   | Federal Register Act                                            |
| FRS                   | Facility Registry Service                                       |
| ft                    | Feet                                                            |
| FTE                   | Full-Time Employees                                             |
| FTIR                  | Fourier Transform Infrared Spectroscopy                         |
| FUND                  | Climate Framework for Uncertainty, Negotiation and Distribution |
| FUR                   | Field Use Rating                                                |
| FY                    | Fiscal Year                                                     |
| GAO                   | Government Accountability Office                                |
| GC                    | Gas Chromatography                                              |
| GCI                   | Gas Cloud Imaging                                               |
| GDP                   | Gross Domestic Product                                          |
| GGRT                  | Greenhouse Gas Reporting Tool                                   |
| GHG                   | Greenhouse Gas                                                  |
| GHGEC                 | Greenhouse Gas Equivalences Calculator                          |
| GHGI                  | Greenhouse Gas Emissions Inventory                              |
| GHGRP                 | Greenhouse Gas Reporting Program                                |
| GIS                   | Geographic Information System                                   |
| GMI                   | Global Methane Initiative                                       |
| GML                   | Gas Mapping Lidar                                               |
| GOR                   | Gas to Oil Ratio                                                |
| GP                    | General Permit                                                  |
| GRI                   | Gas Research Institute                                          |
| GSD                   | Ground Sample Distance                                          |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                            |
|-----------------------|------------------------------------------------------|
| GWP                   | Global Warming Potential                             |
| H <sub>2</sub> O      | Water                                                |
| H <sub>2</sub> S      | Hydrogen Sulfide                                     |
| HAP                   | Hazardous Air Pollutants                             |
| HC                    | Hydrocarbons                                         |
| HF                    | Hydraulic Fracturing                                 |
| HLS                   | Hot Lime Softening                                   |
| hp                    | Horsepower                                           |
| HPC                   | High Performance Computing                           |
| hr                    | Hour                                                 |
| HR                    | Highly Reactive                                      |
| HRRR                  | High Resolution Rapid Refresh                        |
| HRVOC                 | Highly Reactive Volatile Organic Compounds           |
| H <sub>2</sub> S      | Hydrogen Sulfide                                     |
| IAM                   | Integrated Assessment Models                         |
| IARC                  | International Agency on Cancer Research              |
| ICE                   | Incremental Cost Effectiveness                       |
| ICR                   | Information Collection Request                       |
| Id.                   | Identification Numbers                               |
| IEA                   | International Energy Agency                          |
| IEC                   | International Electrotechnical Commission            |
| IESCM                 | Interim Estimates for The Social Costs of Methane    |
| IIASA                 | International Institute for Applied Systems Analysis |
| IIJA                  | Infrastructure Investment and Jobs Act               |
| ILI                   | In-Line Inspection                                   |
| IMEO                  | International Methane Emissions Observatory          |
| IMU                   | Inertial Measurement Unit                            |
| in                    | Inch                                                 |
| IOGCC                 | Interstate Oil and Gas Compact Commission            |
| IPCC                  | Intergovernmental Panel on Climate Change            |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                      |
|-----------------------|------------------------------------------------|
| IPUMS                 | Integrated Public Use Microdata Series         |
| IR                    | Infrared                                       |
| IRA                   | Inflation Reduction Act                        |
| IRFA                  | Initial Regulatory Flexibility Analysis        |
| IRS                   | Internal Revenue Service                       |
| ISA                   | Integrated Science Assessment                  |
| ISO                   | International Organization for Standardization |
| IT                    | Information Technology                         |
| ITRC                  | Interstate Technology and Regulatory Council   |
| IWG                   | Interagency Working Group                      |
| KECC                  | Kentucky Energy and Environmental Cabinet      |
| kg                    | Kilogram                                       |
| LAER                  | Lowest Achievable Emissions Rate               |
| lb                    | Pound                                          |
| LDAR                  | Leak Detection and Repair                      |
| LDAR-Sim              | Leak Detection and Repair Simulator            |
| LDC                   | Local Distribution Company                     |
| LDSN                  | Leak Detection Sensor Network                  |
| LEL                   | Lower Explosive Limit                          |
| LFL                   | Lower Flammable Limit                          |
| LLC                   | Limited Liability Company                      |
| LNG                   | Liquefied Natural Gas                          |
| LSI                   | Leak Survey Inc.                               |
| m, min                | Minute                                         |
| M21                   | EPA Method 21                                  |
| MACT                  | Maximum Achievable Control Technology          |
| MAOP                  | Maximum Allowable Operating Pressure           |
| MAP                   | Methane Analysis Project                       |
| MAP                   | Methane Advisory Panel                         |
| MARS                  | Methane Alert and Response                     |



| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                   |
|-----------------------|-------------------------------------------------------------|
| MATS                  | Mercury Air Toxics Standards                                |
| MB                    | Mass Balance                                                |
| MCFPD                 | Million Cubic Feet Per Day                                  |
| MDL                   | Methane Detection Limit                                     |
| MEET                  | Methane Emissions Estimation Tool                           |
| MERP                  | Methane Emissions Reduction Program                         |
| METAR                 | US Meteorological Terminal Aviation Routine Weather Reports |
| METEC                 | Methane Emissions Technology Evaluation Center              |
| MGLC                  | Mobile Gas Lift Compressors                                 |
| MHA                   | Mandan, Hidatsa, And Arikara Nations                        |
| MIDAC                 | Methane Data Analysis Center                                |
| ML                    | Machine Learning                                            |
| MMT                   | Million Metric Tons                                         |
| MOU                   | Memorandum of Understanding                                 |
| MP                    | Model Plant                                                 |
| mrv                   | Measurement, Reporting and Verification                     |
| MS                    | Mass Spectrometer                                           |
| MSCF                  | Million Standard Cubic Feet Per Day                         |
| Mt                    | Metric Tonnes                                               |
| MVMS                  | Methane/VOC Mitigation System                               |
| MW                    | Molecular Weight                                            |
| MWIR                  | Mid Wave Infrared                                           |
| n.                    | Number                                                      |
| NA                    | Not Applicable                                              |
| NAA                   | Nonattainment Area                                          |
| NAAQS                 | National Ambient Air Quality Standards                      |
| NAICS                 | North American Industry Classification System               |
| NAS                   | National Academy of Sciences                                |
| NASA                  | National Aeronautics and Space Administration               |
| NASEM                 | National Academies of Science, Engineering and Medicine     |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                        |
|-----------------------|------------------------------------------------------------------|
| NATA                  | National Air Toxics Assessment                                   |
| NATO                  | North Atlantic Treaty Organization                               |
| NCP                   | National Oil and Hazardous Substances Pollution Contingency Plan |
| NDC                   | Nationally Determined Contribution                               |
| NDE                   | No Detectable Emissions                                          |
| NDE                   | Nondestructive Examination                                       |
| NEDS                  | National Emissions Data System                                   |
| NEI                   | National Emissions Inventory                                     |
| NEPA                  | National Environmental Policy Act                                |
| NESHAP                | National Emission Standard for Hazardous Air Pollutants          |
| NETL                  | National Energy Technology Laboratory                            |
| NG                    | Natural Gas                                                      |
| NGL                   | Natural Gas Liquid                                               |
| NH <sub>3</sub>       | Ammonia                                                          |
| NHV                   | Net Heating Value of Flare Vent Gas                              |
| NIOSH                 | National Institute for Occupational Safety and Health            |
| NIST                  | National Institute of Standards and Technology                   |
| NM                    | New Mexico                                                       |
| NMED                  | New Mexico Environment Department                                |
| NMOCD                 | New Mexico Oil Conservation Commission                           |
| NNSR                  | Nonattainment NSR                                                |
| NOAA                  | National Oceanic and Atmospheric Administration                  |
| NOE                   | No Exposure Certification                                        |
| NOV                   | Notice of Violation                                              |
| NO <sub>x</sub>       | Nitric Oxide and Nitrogen Dioxide                                |
| NPCA                  | National Parks Conservation Association                          |
| NPO                   | Non-Profit Organization                                          |
| NPRM                  | Notice of Proposed Rulemaking                                    |
| NPV                   | Net Present Value                                                |
| NRDC                  | Natural Resources Defense Council                                |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                              |
|-----------------------|--------------------------------------------------------|
| NREL                  | National Renewable Energy Laboratory                   |
| NSPS                  | New Source Performance Standard                        |
| NSR                   | New Source Review                                      |
| NSWA                  | National Stripper Well Association                     |
| NTTAA                 | National Technology Transfer and Advancement Act       |
| NYCRR                 | New York Codes, Rules and Regulations                  |
| O&M                   | Operation And Maintenance                              |
| OAI                   | Ozone Attainment Initiative                            |
| OAQPS                 | Office of Air Quality Planning and Standards           |
| OCSLA                 | Outer Continental Shelf Lands Act                      |
| OE                    | Operating Envelope                                     |
| OGC                   | Oil And Gas Commission                                 |
| OGCI                  | Oil And Gas Climate Initiative                         |
| OGI                   | Optical Gas Imaging                                    |
| OGIM                  | Oil & Gas Infrastructure Mapping                       |
| OGMP                  | Oil and Gas Methane Partnership                        |
| OIG                   | Office of the Inspector General                        |
| OK                    | Oklahoma                                               |
| OMB                   | Office of Management and Budget                        |
| OOG                   | Office of Oil and Gas                                  |
| OOGM                  | Office of Oil, Gas and Mineral                         |
| OPEC                  | Organization of Petroleum Exporting Countries          |
| OSHA                  | Occupational Safety and Health Act                     |
| PAGE                  | Policy Analysis of The Greenhouse Effect               |
| PAL                   | Plantwide Applicability Limit                          |
| PBR                   | Permits By Rule                                        |
| PE                    | Professional Engineer                                  |
| PFE                   | Potential for Flash Emissions                          |
| PHMSA                 | Pipeline and Hazardous Materials Safety Administration |
| PLC                   | Programmable Logic Controller                          |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                               |
|-----------------------|---------------------------------------------------------|
| PLD                   | Packing Leak Detector                                   |
| PM                    | Particulate Matter                                      |
| POD                   | Probability of Detection                                |
| PPE                   | Personal Protection Equipment                           |
| ppm                   | Parts Per Million                                       |
| PRA                   | Paperwork Reduction Act                                 |
| PRCI                  | Pipeline Research Council International                 |
| PRD                   | Pressure Relief Device                                  |
| PRV                   | Pressure Relief Valve                                   |
| PSC                   | Participant Support Costs                               |
| PSC                   | Production Sharing Contract                             |
| PSD                   | Prevention of Significant Deterioration                 |
| PSE                   | Physicians, Scientists, And Engineers                   |
| psig                  | Pounds Per Square Inch Gauge                            |
| PTE                   | Potential To Emit                                       |
| PTO                   | Paid Time Off                                           |
| PUMA                  | Public Use Microdata Area                               |
| PV                    | Photovoltaic                                            |
| PV                    | Present Value                                           |
| PVPFR                 | Peak Vapor Pressure Flow Rate                           |
| QA                    | Quality Assurance                                       |
| QC                    | Quality Control                                         |
| QMRV                  | Quantification, Monitoring, Reporting, And Verification |
| RACM                  | Reasonably Available Control Measures                   |
| RACT                  | Reasonably Available Control Technology                 |
| RCA                   | Root Cause Analysis                                     |
| RCP                   | Representative Concentration Pathways                   |
| RCRA                  | Resource Conservation and Recovery Act                  |
| REC                   | Reduced Emission Completion                             |
| RFA                   | Regulatory Flexibility Act                              |

| <b><u>Acronym</u></b>    | <b><u>Description</u></b>                          |
|--------------------------|----------------------------------------------------|
| RFF                      | Resources For the Future                           |
| RFI                      | Resource Facility Investigation                    |
| RIA                      | Regulatory Impact Analysis                         |
| RICE                     | Reciprocating Internal Combustion Engines          |
| ROI                      | Payout/Return on Investment                        |
| ROW                      | Right of Way                                       |
| RRC                      | Railroad Commission                                |
| RSG                      | Responsibly Sourced Natural Gas                    |
| RTC                      | Response To Comments                               |
| RUL                      | Remaining Useful Life                              |
| RULOF                    | Remaining Useful Life and Other Factors            |
| s, sec                   | Second                                             |
| SAB                      | Science Advisory Board                             |
| SBAR                     | Small Business Advocacy Review                     |
| SBREFA                   | Small Business Regulatory Enforcement Fairness Act |
| SCADA                    | Supervisory Control and Data Acquisition           |
| SCC                      | Social Cost of Carbon                              |
| SC-CH <sub>4</sub> , SCM | Social Cost of Methane                             |
| scf                      | Standard Cubic Feet                                |
| SCF                      | Significant Contribution Finding                   |
| SC-GHG                   | Social Cost of GHGs                                |
| SEC                      | U.S. Securities and Exchange Commission            |
| SER                      | Small Entity Representative                        |
| SERP                     | Super Emitter Response Program                     |
| SI                       | Smoke Index                                        |
| SIP                      | State Implementation Plan                          |
| SJVAPCD                  | San Joaquin Valley Air Pollution Control Board     |
| SLCF                     | Short-Lived Climate Forcer                         |
| SNPR                     | Supplemental Notice of Proposed Rulemaking         |
| SOCMI                    | Synthetic Organic Chemical Manufacturing Industry  |

| <b><u>Acronym</u></b> | <b><u>Description</u></b>                                       |
|-----------------------|-----------------------------------------------------------------|
| SOP                   | Standard Operating Procedures                                   |
| SPOT                  | Sensor Placement Optimization Tool                              |
| SRMP                  | State Resource Management Plan                                  |
| STB                   | U.S. Surface Transportation Board                               |
| STEM                  | Storage Tank Emission Management                                |
| STEPP                 | Storage Tank Emissions Pilot Project                            |
| STEPS                 | National Service, Transmission, Exploration & Production Safety |
| TAC                   | Texas Administrative Code                                       |
| TAC                   | Total Annual Cost                                               |
| TAS                   | Treatment As a State                                            |
| TCI                   | Total Capital Investment                                        |
| TD                    | Top Down                                                        |
| TDLAS                 | Tunable Diode Laser Absorption Spectroscopy                     |
| THC                   | Total Hydrocarbons                                              |
| TIP                   | Tribal Implementation Plans                                     |
| TOC                   | Total Organic Compound                                          |
| typ                   | Tons Per Year                                                   |
| TRC                   | Texas Railroad Commission                                       |
| TSCA                  | Toxic Substances Control Act                                    |
| TSD                   | Technical Support Document                                      |
| TX                    | Texas                                                           |
| UARG                  | Utility Air Regulatory Group                                    |
| UAV                   | Unmanned Aircraft Vehicle                                       |
| UB                    | Uinta Basin                                                     |
| UBR                   | Uinta Basin Railway                                             |
| UCLA                  | University of California-Los Angeles                            |
| UGRB                  | Upper Green River Basin                                         |
| UHC                   | Unburned Hydrocarbons                                           |
| UIC                   | Unit Identification Code                                        |
| UIC                   | Underground Injection Control                                   |

| <b><u>Acronym</u></b>  | <b><u>Description</u></b>                                         |
|------------------------|-------------------------------------------------------------------|
| UMRA                   | Unfunded Mandates Reform Act                                      |
| UN                     | United Nations                                                    |
| UNCC                   | United Nations Climate Change                                     |
| UNDRIP                 | United Nations Declaration on The Rights of Indigenous Peoples    |
| UNEP                   | United Nations Environment Program                                |
| UNESCO                 | United Nations Educational, Scientific, And Cultural Organization |
| UNFCCC                 | United Nations Framework Convention on Climate Change             |
| UNFPPCC                | UN Framework Convention on Climate Change                         |
| UOG                    | Unconventional Oil and Gas                                        |
| USA, US, U.S,<br>U.S.A | United States of America                                          |
| USC                    | United States Code                                                |
| USC                    | University Of Southern California                                 |
| USD                    | United States Dollars                                             |
| USDA                   | U.S. Department of Agriculture                                    |
| UTC                    | Universal Time Coordinated                                        |
| VDC                    | Volts Direct Current                                              |
| VE                     | Visible Emissions                                                 |
| VIIRS                  | Visible Infrared Imaging Radiometer Suite                         |
| VIIRS                  | Visible Infrared Imaging Radiometer Suite                         |
| VOC                    | Volatile Organic Compounds                                        |
| VRD                    | Vapor Recovery Device                                             |
| VRT                    | Vapor Recovery Tank                                               |
| VRU                    | Vapor Recovery Units                                              |
| WSTN                   | Western States and Tribal Nations Natural Gas Initiative          |
| yr                     | Year                                                              |
| ZRF                    | Zero Routine Flaring                                              |

## **VOLUME ONE**

**Standards of Performance for New, Reconstructed, and Modified  
Sources and Emissions Guidelines for Existing Sources: Response to  
Public Comments on the November 2021 Proposed Rule**

**(86 FR 63110, November 15, 2021)**



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## Chapter 1. Introduction

This document provides EPA's responses to public comments on the proposed *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* published in the *Federal Register* on November 15, 2021, at 86 FR 63110.

Just over 472,000 public comments were received on the proposal. The EPA Docket Center consolidated mass mail campaigns, form letters and petitions into single DCNs, resulting in over 1,270 posted comments. (Note: Batches of substantially similar mass mail campaigns, form letters and petitions are considered as a single "unique" comment.). Each of these comments were reviewed and significant comments relevant to this action have been summarized and included in this document.

Of the more than 1,270 "unique" comment letters received over 62 percent originated from individual private citizens, 15 percent are from industry (including industry associations), 8 percent are from environmental and public advocacy groups, 6 percent are mass mail campaigns/petitions (representing nearly 470,000 individuals), 6 percent are from state, local, federal, and tribal governments/representatives, 3 percent are from other advocacy groups, including financial companies, and less than 1 percent are from academia.

In addition to public comment submissions to the Docket, EPA held a 3-day virtual public hearing, November 30, 2021, through December 2, 2021, to provide the public the opportunity to present comments and information on the Agency's proposed new source performance standards (NSPS) and emissions guidelines (EGs) to reduce methane and other harmful pollution from the oil and natural gas industry.

Nearly 300 speakers, from members of the public either representing themselves or speaking on the behalf of one or more organization or agency, provided oral testimony over the course of three days. Live, daily testimonies were recorded by a certified court reporter and documented in official transcripts. Emailed written copies of testimonies and other supporting information received were uploaded, separately to the Docket.

The public comment period for the proposed rule was first scheduled to close on January 14, 2022; however, EPA received several requests to extend the public comment period. Accordingly, EPA extended the deadline to submit comments by seventeen (17) days, to January 31, 2022. The comment period officially closed on January 31, 2022. A general overview of all the comments received follows in Sections 1.1 through 1.4 of this Chapter. More-detailed comments provided by these commenters (some of which are highlighted in the general overview) on the November 2021 Proposal have been summarized and included in Chapters 2 through 23 of this Volume I. Mass Mail Campaigns/Petitions

## 1.1 Mass Mail Campaigns/Petitions

Nearly 90 individual entries submitted to the Docket are categorized as mass mail campaign comments; representing roughly 470,630 of the more than 472,000 public submissions received by the Docket on the November 2021 Proposal (> 99 percent).

Mass mail campaigns can be classified as either mailers/form letters or petitions. For the purposes of this Response to Comment (RTC) document, mailers and form letters (including postcards) are comment submissions submitted by individual commenters, but present substantially similar (if not identical) remarks. These campaigns are typically sponsored by an organization/institution. Petitions are pre-written letters or statements (by a sponsoring agency/institution) requesting action that are signed by persons supporting what is stated in the pre-written letter or statement.

Under this proposal, mailers/form letters (including postcards) account for roughly 91 percent of the total number of mass mail campaign comments submitted to and identified by the Docket – representing more than 95,000 private citizens. Most contributors submitted templates provided by the known sponsoring organization(s) without change; however, it is worth noting that a few commenters customized the template(s) – e.g., to include statements describing personal experiences with deteriorating health. Petitions account for nearly 9 percent of the mass mail campaign comments identified and represent more than 373,900 private citizens.

Roughly 22 percent of mass mail campaign comments were prepared by an unknown sponsoring organization. The remaining campaigns were generated from various known groups and organizations representing a wide range of sectors, including academia, religion, and environmental/public advocacy. Most mass mail campaign comments received (over 40 percent) are sponsored by advocacy or interest groups, comprised of mainly faith-based organizations. At least one campaign, in support of the rule, represents 59 undersigned public representatives from the Commonwealth of Pennsylvania (last 4 digits of DCN-0995). (Note: Although a late submission, it is worth noting that at least one mass mail campaign (representing 88 individuals) was prepared and submitted in Spanish [last 4 digits of DCN-1454]).

It is worth noting that roughly 39 percent of comments prepared by “Private Citizens” included one or more mass mail campaign arguments; however, these comments varied enough to be considered as a separate entry by the Docket. These comments are summarized in section 1.4.1 of this Chapter (as part of the private citizen summary).

Mass mail comment campaigns uniformly support the proposed rule and applaud EPA’s efforts to reduce methane emissions/pollution from industrial sources (the oil and natural gas sector). Campaigns strongly believe that the proposed rule is an essential step forward towards protecting public health and tackling/mitigating climate change, and often argue the point that methane is over 80 times more potent than carbon dioxide. Many of the campaigns cite/reference the amount of methane emissions generated from the oil and gas sector (16 million metric tons) and warn that without immediate action, methane emissions and its impact on public health, primarily the health of vulnerable populations (e.g., children and communities

located near oil and gas industry operations) and the environment will continue to worsen.

While the campaigns agreed that, overall, the proposed rule is a step towards the right direction; nearly all urged the Agency to further strengthen the proposed rule. Requests repeatedly made include, for example:

- End routine flaring (except in emergency situations);
- Strengthen monitoring requirements for smaller, low-producing wells – increase the number of inspections;
- Maintain strong requirements for the deployment of zero-emitting controllers;
- Develop a process for the incorporation of monitoring data from third parties (e.g., a process that engages with frontline communities, educates and certifies community members and requires immediate follow-up on complaints filed by community leaders/members);
- Require monitoring and plugging of abandoned wells; and
- Reduce methane pollutions (using existing low-cost technologies) from the oil and natural gas industry by 65 percent by 2025.

More than 40 percent of the mass mail campaigns spoke directly on the issue of environmental justice. These campaigns were prepared by and represent roughly 12,600 black church leaders and community members, covering multiple states. These faith-based mailers express concerns that low-wealth communities and communities of color, particularly black communities, are disproportionately impacted by air pollution (methane emissions from the oil and gas industry) and climate change; stating that more than 1 million African Americans live within a half-mile of an existing natural gas facility.

Moreover, multiple campaigns explicitly reference methane pollution reduction requirements currently imposed by the states of Colorado and New Mexico, as examples of efficient and successful rulemakings, and encouraged the Agency to follow in these states' path and implement more stringent standards.

A list of campaigns received is provided in **Appendix B** to this document. Examples of a few of the mass comment campaigns can be found in **Appendix C** to this document.

## 1.2 General Support/Opposition

### Support

Roughly 74 percent (or more than 900 comments) of the unique written comments received support the general intent of EPA's proposed rule, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* published in the *Federal Register*, including one or more proposed requirements. Support for the proposed rules can be broken down by commenter type as follows: over 65 percent originated from individual private citizens (including mass mail campaign variations), 10 percent are from environmental and public advocacy groups, 10 percent are from industry (including industry associations), 9 percent are mass mail

campaigns/petitions, 4 percent are from state, local, federal, and tribal governments/representatives, 2 percent are from other advocacy groups (including financial companies), and less than 1 percent are from academia.

Commenters overwhelmingly believe that the proposed action is a significant step forward to combating climate change and its impacts (including economic productivity and social welfare), improving air quality, and protecting public health and the environment. Commenters remind that methane is a potent greenhouse gas (GHG) (traps about 80 times as much as heat as carbon dioxide) and point to the oil and gas industry as the biggest contributor. Several commenters expressed particular concern over the health and wellbeing of communities of color and tribal communities – which are often disproportionately impacted by harmful air pollution from oil and gas operations – and agree that the proposed rule could aid in addressing these environmental justice issues. Though commenters generally support the proposed rule and EPA’s efforts to reduce methane emissions, several of the commenters feel that the proposed changes do not go far enough and call on the EPA to further tighten rules surrounding the release of methane emissions from the oil and natural gas industry. In such cases, commenters highlighted instances where the rule could be improved upon and presented one or more recommendations to further strengthen requirements. Two central themes or requests included that the EPA end the practice of routine flaring at oil and gas operations (i.e., ban flaring, except for emergencies) and require regular monitoring at all smaller, high-polluting and leak-prone wells. While several commenters cite Colorado and New Mexico as examples of states with successful flaring and low-production well policies; overall, commenters stress that current regulations and voluntary actions achieved by the oil and gas industry alone are not enough to combat climate change and improve air quality and underscore the need for federal oversight.

### Oppose

Approximately 21 percent (or more than 250 comments, largely from private citizens, followed by industry/trade association representatives, government officials/organizations, nonprofit organizations and other advocacy groups) of the unique written comments received generally oppose one or more specific action. Generally, commenters worry that imposing additional regulations on the oil and gas industry, a sector which many believe is already over regulated, would significantly impact the economy – e.g., would slow U.S. economic growth, result in job losses, bankrupt small, local oil and gas producers, and create higher energy prices for consumers. Many of these commenters further argue that the proposed rule is an example of over-regulation and excessive federal government overreach. In most cases, commenters highlighted specific areas in the rule where they believe further improvements, or additional clarification are needed to correct requirements or language that they considered to be lacking.

Two commonly discussed areas of concerns include the reference to community involvement in identifying/detecting large-volume emission events and inclusion of marginal wells (or low production wells). Overall, commenters express that the reference to community involvement in identifying/detecting large-volume emission events is too vague and would lead to uninformed and untrained community members in and around oil and natural gas production operations. These commenters unanimously agree that the rule needs to be clear that untrained individuals

without appropriate safety equipment should not be visiting well sites or tank batteries to measure emissions; not only would they be trespassing on private property, but measuring emissions without training and without the proper equipment is dangerous. Similarly, commenters opposed the inclusion of marginal wells (or low production wells) in the proposed rule; claiming that emissions from these production operations are insignificant – marginal wells have a diminished capacity to emit methane. According to these commenters, marginal wells can become economically unviable for small independent drillers if new (inspection and repair) rules are too costly. These commenters generally remind the EPA that marginal wells historically have been exempted from complying with previous, similar regulations and many of the commenters feel that the Agency should maintain the exemption status.

Roughly 3 percent of the unique comments (over 35 comments, mostly from industry and government representatives) requested that EPA extend the public comment period for the proposed rule; citing that the amount of time granted to prepare and submit remarks is insufficient.

Approximately 3 percent (over 30 comments, primarily from private citizens) of the unique comments received, conveyed general concerns about the environment and/or public health but did not specifically comment on the proposed rules.

### **1.3 Summary of Public Hearing Comments**

As previously noted, the EPA held a virtual public hearing November 30, 2021, through December 2, 2021, to provide the public the opportunity to present comments and information on the Agency's proposed updates to NSPS and EGs to reduce methane and other harmful pollution from the oil and natural gas industry. Over the course of three days, nearly 300 speakers (roughly 100 speakers per day), from members of the public either representing themselves or speaking on the behalf of one or more organization or agency, provided oral testimony. Testimonies can be broken down by commenter type as follows: over 53 percent originated from environmental and public advocacy groups (including various nonprofits and faith communities), nearly 40 percent originated from individual private citizens (including students, retirees, community members and volunteers), 4 percent originated from industry (including industry associations), and 3 percent originated from government agencies representatives and elected officials. It is worth noting that some speakers prepared and submitted separate, more detailed comments to the Docket. These remarks are discussed elsewhere in this document. The public hearing transcripts for the virtual public hearing are accessible at [regulations.gov](https://www.regulations.gov) (see EPA-HQ-OAR-2021-0317-1528).

Environmental and public advocacy groups generally applauded EPA's efforts to reduce methane emissions/pollution from industrial sources (the oil and natural gas sector). Speakers strongly expressed that they believed that the proposed rule is a step towards the right direction and urged the Agency to finalize the strongest most comprehensive rule. While speakers agreed that the proposed rule would help protect public health and help mitigate climate change, some speakers suggested that the proposal, as written, could be further strengthened and proposed more protective standards – i.e., offered one or more recommendations aimed at achieving more comprehensive emissions reductions from oil and natural gas facilities, such as

supporting more frequent monitoring (quarterly instead of annually) and prohibiting the practice of routine flaring.

Private citizens testimonies echoed many of the remarks made by environmental and public advocacy groups, and at times also included personal accounts – experiences and a description of various environmental and health impacts resulting from climate change and/or exposure to air pollutants, including methane, from oil and gas facilities. Several of these speakers underscored the point and expressed ongoing frustration that the oil and gas industry is heavily subsidized even though the industry externalizes health and environmental costs. Many of these speakers, as well as of other private citizens suggested that the oil and gas industry cannot self-regulate, nor can we (private citizens) rely on volunteering efforts as a sole means to address climate change and adequately reduce methane and called on the EPA to finalize the strongest most comprehensive rule.

In general, industry representatives supported the intent of the proposed rule – reducing methane emissions – many of which, emphasized their company's commitment to protecting public health and the environment, as well as their commitment to participating in ongoing engagement efforts with community members, regulators, etc., to further reduce impacts from the oil and gas industry. A few industry speakers requested, informally, an extension of the public comment period (by an additional 30-, 60-, or 90- days); arguing the allotted time is too short to provide an adequate response. Other representatives identified one or more requirements in the rule which they specifically opposed, including for example, encouraging local residents and community members to evaluate and access onsite oil and gas equipment/identifying emissions at oil and gas locations. In this example, industry representatives warn against encouraging untrained public members that do not possess the right protective equipment to check equipment as they may get seriously injured. At least one industry representative (whose members operate natural gas compressors, stations, storage fields and interstate pipelines that will be subject to these rules in 46 of the 48 contiguous state) generally supported the revisions to NSPS OOOOa, as written, and offered thoughts specific to NSPS OOOOb and EG OOOOc. A few industry representatives noted the importance of the oil and gas industry to state economies (provide jobs), and at least one representative suggested that the proposed regulations are an attempt to bankrupt American oil and gas companies and do away with fossil fuels. In contrast, another industry representative expressed hope that the proposed rule will lead to innovative approaches to meeting emissions reduction challenges and briefly described available technologies that can be used – e.g., Airdar, a cousin to radar and sonar.

Speakers representing states, federal, local and tribal governments overwhelmingly supported the proposal and EPA's overall intent to limit/reduce methane pollution from oil and gas operations and urged the Agency to strengthen the proposed requirements to maximize climate and health benefits. These speakers agreed that methane emissions generated from oil and gas operations are harmful to public health and the environment, with at least one commenter underscoring the point that communities of color and/or low-income communities are disproportionately impacted. Another commenter reminded that some states' economies, such as theirs, are supported by (dependent on) tourism (including outdoor recreation activities) and expressed concerns over economic viability (impacts to diners, hotels, camping sites, etc.).



## **1.4 Summary of General Positions by Commenter Type**

### ***1.4.1 Private Citizens***

#### Support

Most private citizens (approximately 77 percent of the “unique” comments received) generally support the proposed actions/revisions to the NSPS and EG for new and existing sources in the oil and natural gas sector. Similar to public submissions included as part of mass mail campaigns, several of the commenters express that while the proposed rule is a step in the right direction, they urge the Agency to go even further (*e.g.*, ban flaring and strengthen monitoring requirements). Several private citizen commenters specifically support the EPA regulating emissions of volatile organic compound (VOC) and methane emissions to address public health, environmental health and climate change concerns (and provided several examples to support their concerns).

#### Oppose

Approximately 19 percent of the “unique” comments received from private citizens generally oppose the proposed revisions to the NSPS and EG for new and existing sources in the oil and natural gas sector. Most of these commenters express that the oil and gas industry is already highly regulated, and warn that, if enacted, the proposed regulations would lead to economic hardships (*e.g.*, an increase in job losses, higher energy costs and increases in the cost of living in the United States) and production hardships (*i.e.*, cutting back domestic oil and gas production and the closing of small production facilities) that would be felt both, domestically and internationally. A few commenters also assert that the concept of climate change is not real and there is no climate crisis – methane is a natural occurring gas and is not problematic. Some commenters also question the benefits of the proposed rule as it relates to mitigating climate change, noting emission reductions imposed on domestic production in America does little to impact production or reduce methane emissions from other countries (*e.g.*, China and India).

#### Other

Approximately 4 percent of the comments received from private citizens include broad remarks about the environment, public health, etc., but do not comment specifically on the proposed requirements included in the Proposal.

Less than 1 percent of private citizens requested an extension to the public comment period – an additional 90 days to ensure appropriate time to review new regulations and accompanying documents, as well as to ensure that the EPA has sufficient time to review information.

### ***1.4.2 Academia***

Comments received from academia unanimously (100 percent) support EPA’s November 2021 Proposal. The commenters generally commend the Agency for their efforts to control methane

emissions from new and existing sources in the oil and gas industry and overwhelmingly agree that the proposed rule is an important step (in the right direction) to comprehensively protect public health (particularly at-risk, frontline communities and communities of color) and combat climate change (e.g., creating more frequent and more dangerous weather events); with many underscoring the point that oil and gas production is the largest industrial source of methane pollution in the U.S. One commenter referenced several studies that found correlations between living closer to more wells and more actively producing wells and increased risk of preterm birth, migraine headache, depression, and cardiovascular disease in Pennsylvania (Casey et al. 2016, Casey et al. 2018, Casey et al. 2019, Tustin et al. 2017, Rasmussen et al. 2016). These same studies also suggest that people of color are more likely to live closer to methane super-emitters, suggesting that reducing emissions from oil and gas wells is also an issue of environmental justice.

While commenters generally support the intent of the rule, nearly all believe that the November 2021 Proposal does not go far enough and urge the Agency to strengthen proposed requirements. Commenters propose one or more specific recommendations aimed at toughening EPA's final rule and maximizing net benefits. Recommendations offered are similar to suggestions made by other commenters, including private citizens – such as, end routine flaring, establish a meaningful and effective process that allows communities to report super-emitter events directly to the EPA, require regular monitoring at all smaller, leak-prone wells, require electric pumps at compressor stations and processing plants. At least one commenter maintains, as it relates to maximizing net social welfare, that the EPA should propose standards for additional sources (including abandoned and unplugged wells, flares, pipeline pigging operations, and tank truck loading operations) in the oil and gas sector.

#### ***1.4.3 Industry/Trade Association***

Industry support (including industry associations) for EPA's proposed actions is nearly split, with roughly 47 percent of the industry comments supporting one or more components of the proposed rule and nearly 45 percent opposing them.

##### **Support**

Overall, commenters in favor of the proposed amendments support EPA's efforts to protect public health and address climate change through reductions in methane emissions – which they echo is a major GHG – and are in support of reasonable methane regulations. Several industry commenters reiterate their commitment to measuring and mitigating methane emissions from their own operations and briefly discuss current efforts underway; adding that methane detection technologies have improved dramatically over the years.

A few industry commenters (many of which are vendors) provide product-specific equipment/material(s) and services offered (or sold) which they believe could be used to achieve EPA's methane emissions reduction goals.

There are also industry commenters, that, although they generally support the rule, request that EPA consider and avoid duplication or unnecessary administrative burdens in complying with state and federal standards. These commenters also request that the EPA consider some of the comprehensive regulatory and proactive operational approaches already underway in states, including New Mexico, and voluntary efforts/initiatives related to methane emissions that are currently underway throughout the natural gas supply chain.

### Oppose

Conversely, several industry commenters express opposition to one or more proposed requirements (approximately 44 percent) and maintain that the November 2021 Proposal is unnecessary; largely expressing that they believe that the industry sector is already overregulated. These commenters warn that additional regulations would significantly impact the economy.

Several industry commenters specifically object to what they say is the proposal's one-size-fits all approach, which the commenters contend fails to adequately account for impacts to small businesses – e.g., the cost of monitoring and implementation/compliance requirements, which they believe will burden many small business owners with unjustified costs leading to early plugging and abandonment of marginal wells that still have recoverable reserves. These commenters recommend, in general, that the EPA approve a longer implementation period of the rule for small businesses. At least one commenter warns that this early plugging and abandonment could cause a decline in U.S. domestic production nationwide resulting in increased dependency on foreign crude and natural gas, price increases to consumers for their energy and significant job losses across the oil and gas.

### Other

Approximately 8 percent of the industry comments requested an extension of the public comment period (anywhere from 30- to 60- to 90-days) for EPA's proposed rule (87 FR 74702, December 6, 2022); citing, in general, insufficient time to respond adequately and appropriately. Commenters unanimously agree that the complexity of the proposed rule, and its potential impact on operational requirements of numerous aspects of the natural gas and oil industry (not previously subject to regulation under the Clean Air Act (CAA), section 111(d)), suggests that sufficient (additional) time is needed to fully analyze the impact of the proposed regulations. Commenters further justify the need for additional time by noting the level and number of staff/members needed to fully analyze the proposed rule.

#### ***1.4.4 State/Local/Tribal/Federal Governments***

Roughly half (approximately 50 percent) of the comments submitted by government agencies and representatives (mostly comprised of states) generally support EPA's efforts to update, expand and strengthen the new source performance standards, or NSPS (proposed in November 2021 under CAA section 111(b)), for methane and other harmful pollutants (e.g., VOC

emissions) from new, modified, and reconstructed oil and natural gas operations, and to establish the EGs requiring regulation of methane from existing sources.

### Support

Overall, commenters that support the proposal agree that significantly reducing methane – a potent GHG – from the oil and natural gas industry will generate significant climate benefits as well as direct health benefits to communities harmed by local and regional emissions, including low-wealth, communities of color (including tribal communities). While commenters prepared and submitted individual, separate remarks on the proposed rule based on factors that are unique to their state or tribal community, a number of commenters offer technical comments and/or one or more recommendations aimed at further strengthening the rule that are identical to or resemble recommendations proposed by non-governmental representatives (including private citizens, environmental groups, etc.) – such as, limiting flaring to emergencies situations only, revising the proposed requirements for fugitive emissions monitoring and repair (increases in frequency), transitioning to zero-emitting technologies for controllers, eliminating venting of associated gas from oil wells, strengthening requirement for storage tanks, etc.

One commenter (representing 153 state and local air pollution control agencies) appreciates that the proposed rule would help state and local agencies in their efforts to achieve and maintain compliance with national ambient air quality standards (NAAQS) and is also supportive of the development of an example state plan and model rule language for each segment of the oil and gas industry that can be incorporated directly or by reference to meet EPA’s emission guidelines.

### Oppose

Over a quarter of the comments (approximately 27 percent, comprised mostly of states) submitted by state, local, federal and tribal governments claim that the proposed rule, as written, poses several problematic and concerning issues, and has the potential to substantially impact states and tribal communities. Specific concerns vary by commenter and commenter type. However, most commenters (including state and federal representatives and at least one commenter representing an association of local governments) express concerns that the amount of resources (cumulative costs) required to account for the anticipated increase in workload, in order to comply with and implement the proposed rule – e.g., in approving permits, reviewing monitoring data and reports, and ensuring compliance with the proposed emission guidelines for existing sources – will come at a significant cost to industry and states. Several state government commenters, particularly those home to oil and natural gas facilities, also express concern that the proposed actions would negatively impact production in their states, resulting in an increase in loss of jobs, as well as a reduction in state and federal revenues.

Several commenters also suggest that the November 2021 Proposal is redundant; highlighting that several states, including Colorado already have oil and gas regulations in-place that are comparable and, in some cases, more stringent than the proposed rule. These commenters

underscore the point that companies are currently making efforts to reduce methane emissions – e.g., via installing methane capturing systems, and warn against potentially getting in the way of innovation and investment in methane emissions reducing activities – by indirectly penalizing voluntary efforts and innovative solutions, through the addition of new regulatory burdens, which states and companies would not have been subject to had they not installed these innovative systems.

A few commenters objected to one or more specific actions pertaining to state plan development and implementation under the EG, and due to the complexity of the proposed EG, feel that they could benefit from further guidance.

In similar opposition, tribal commenters overwhelmingly express concerns that, if finalized as written, the proposed rule would unreasonably burden development of tribal energy resources. The commenters explain that the production of oil and gas on tribal lands has played a significant, historic role in tribal economic development – e.g., royalties/revenues used to fund, for example, critical resources, including housing, healthcare, and while they appreciate the intent of EPA’s effort, they ask that the Agency consider – and disclose – the full breadth of impacts it will have on tribal communities that rely (economically) on oil and gas production. Commenters remind, that as tribal communities, they face a set of unique challenges – e.g., resulting from the shared governance, and applaud the Agency for including options for tribes to exercise their inherent sovereignty by achieving Treatment as a State (TAS) and developing and implementing Tribal Implementation Plans (TIPs). Commenters ask that the EPA offer an expedited TAS and TIP development and approval process, and an expanded grant funding to assist with initial compliance costs and maximize limited tribal resources and staff capacity. Moreover, commenters also request that the Agency clarify, for example, whether a single federal plan would apply to all Indian reservations without TIPs or whether individual federal plans will be developed for each such Indian reservation.

#### Other

Remaining comments (approximately 22 percent, comprised predominately of state and federal representatives, and state and local air agencies and associations) ask that the EPA extend the public comment period (anywhere from 30- to 60- to 90-days); citing, in general, insufficient time to respond adequately and appropriately. Nearly all commenters reference the complexity of EPA’s November 2021 Proposal as the primary reason for requesting an extension.

### ***1.4.5 Environmental and Public Advocacy Groups***

#### Support

Comments (roughly 96 percent) from environmental and public advocacy groups overwhelmingly support the November 2021 Proposal and appreciate the Agency’s efforts to reduce methane emissions from oil and gas operations and urge the Agency to promptly finalize the proposal. Many of these commenters support and reiterate one or more proposed regulatory

changes also supported by non-environmental and public advocacy groups (including private citizens, industry, academia, etc.), including regulating oil and gas based on emissions – not on the amount of production from a particular well, requiring a zero-percent leak rate from controllers, prohibiting venting of methane, addressing leaks from storage tanks, providing an advanced screening approach for leak detection and remediation, and reducing emissions from maintenance activities, like liquids unloading.

Most commenters discuss climate change impacts, including its effect on public health (e.g., exposure to toxicity that cause asthma and other health problems) – particularly the health of minority and frontline communities/tribes, but while supportive of the Agency’s efforts to reduce emissions, many of the commenters echo feelings noted by other commenter types (including private citizens, academia, industry, etc.) that the proposed rule does not go far enough. These commenters collectively urge the EPA to pass the strongest possible regulations governing methane emissions in the oil and gas industry, and identify a number of regulatory areas (many of which have been discussed already), which they believe need tightening of the requirements to further limit emissions – i.e., regular monitoring should be conducted at all facilities, including those where site-level baseline methane emissions are below 3 tpy, address emissions from smaller storage tanks, prohibit routine flaring at oil and gas sites, incorporate emission monitoring by community groups, and require monitoring and plugging at abandoned and improperly plugged wells.

### Oppose

Remaining comments (roughly 2 percent) generally opposed the November 2021 Proposal. While specific concerns vary by commenter, at least one advocacy group questions how the Agency gauges the rule’s effectiveness; stating the proposed rule’s Regulatory Impacts Analysis (RIA) does not properly account for the standards’ impact on climate change.

### ***1.4.6 Other/Other Advocacy Groups***

#### Support

Comments (approximately 80 percent) received from other advocacy groups (mostly private equity/investment firms, but also includes union organizations) support the November 2021 Proposal and believe, in general, it is an important step in identifying sound investments needed to tackle climate change – to both reduce emissions and improve public health/air quality (would result in significant emission reductions from ozone precursors, air toxics etc.), as well as maintain economic stability.

Moreover, commenters in support of the November 2021 Proposal agree that companies need to increase investments in clean energy; many asserting that to ensure economic stability and achieve necessary financial returns, the world needs to transition to a more sustainable global economy. Nearly all these commenters echo one or more previously made concerns – e.g., methane is a potent GHG, and identify the changing climate as an extraordinary environmental

challenge with far-reaching economic, environmental, and societal implications that create risks (and opportunities) for companies and investors alike. These commenters agree, in general, that the need for stronger regulation of methane emissions from the oil and gas industry is necessary to help address this challenge and recommend that the EPA:

- Maintain strong requirements for the deployment of zero-emitting controllers;
- Maintain or expand strong leak monitoring and repair standards, including expanded use of advanced leak detection technologies;
- Expand upon the November 2021 Proposal to include all potentially significant sources of methane emissions, including smaller leak-prone wells, subject to emission standards;
- Sets a near-term end date for operators to cease routine flaring of natural gas at oil and gas facilities, as states like Alaska, Colorado and New Mexico have already done;
- Establish a transparent, credible and empirically based methane emissions reporting framework to improve the accuracy of reported methane emissions data, enabling investors to clearly differentiate between leaders and laggards;
- Regulate against orphan and abandoned wells, which are a significant source of methane emissions and a risk to public health and safety; and
- Incorporate community-based monitoring which is critical for those living closest to development.

One commenter (representing farmers union members) believes that the adoption of strong methane rules is critical to protecting rural communities and agricultural heritage. The commenter describes the impacts of climate change – e.g., severe droughts and floods, increases in range of pests, more disease overall and lower crop and livestock yields, etc., on agriculture, food, and related industries. At least one commenter states that the agriculture sector and related industries contributed to more than \$1.1 trillion to the U.S. economy in 2019 and provided 19.7 million full- and part time jobs in 2020.

### Oppose

Approximately 20 percent of commenters (comprised of financial firms) oppose the November 2021 Proposal as written; arguing that the EPA has not fully considered the impact of this proposed rule on small businesses. Commenters request that EPA consider a broader range of regulatory flexibilities to reduce the cost to small businesses in the supplemental proposal.

## Chapter 2. Summary of Proposed Action for NSPS OOOOa

### 2.1 General Support

Comment: Several commenters (0437-New York Office of the State Comptroller, 0598-Countrymark Energy Resources, LLC (CER), 0756-Baker Hughes, 0820-Pioneer Natural Resources USA, Inc. (Pioneer), 0836-Domestic Energy Producers Alliance (DEPA); 0458-Maryland Department of the Environment (MDE), 0802-Kraken Oil and Gas LLC (Kraken), 1294-Ohio Clinicians for Climate Action (OCCA), 0817-GPA Midstream Association (GPA), 0938-Texas Oil & Gas Association (TXOGA), 0814-Independent Petroleum Association of America (IPAA) *et al.*, 1391-Interstate Natural Gas Association of America (INGAA)) provided general support for the proposed retention of certain aspects of the 2020 Technical Rule.<sup>1</sup> Commenter (0817-GPA) states that the changes made in the 2020 Technical Rule were sound, practical revisions designed to streamline the regulatory process while continuing to ensure that emissions were controlled appropriately. Commenter (0756-Baker Hughes) believes that the EPA's proposed revisions to NSPS OOOOa are necessary to ensure that important amendments made in the 2020 Technical Rule apply to NSPS OOOOa to address the technical and implementation issues that result from the CRA disapproval of the 2020 Policy Rule.<sup>2</sup>

Commenter (0802-Kraken) specifically supports EPA's action to reinstate the 2020 Technical Rule amendments to include:

- Fugitive emissions monitoring (initial monitoring requirements, monitoring frequency – compressor stations, monitoring frequency – well sites, low production well sites, schedule for repairing leaks).
- Fugitive emissions monitoring requirements and modifications (modifications of a well site that is a separate tank battery surface site).
- AMEL (incorporating state requirements, streamlining application requirements for using emerging technologies).
- Pneumatic pumps.
- Engineer certifications for CVS.
- Storage vessels (tanks).
- Other amendments (onshore natural gas processing plants, recordkeeping and reporting, well completions).

Similarly, commenter (0814-IPAA *et al.*) specifically supports the following 2020 Technical Rule amendment revisions to NSPS OOOOa:

- Allow the use of a separator at a nearby centralized facility or well pad that services the well affected facility during flowback, as long as the separator can be utilized as soon as it is technically feasible for the separator to function.

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<sup>1</sup> “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration,” 85 FR 57398 (Sept. 15, 2020) (“2020 Technical Rule”).

<sup>2</sup> “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,” 85 FR 57018 (Sept. 14, 2020) (“2020 Policy Rule”).



- The separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback.
- Clarification to definition of “flowback” and what is not included in the definition of “flowback.”
- Changes and/or streamlining recordkeeping and reporting requirements.
- Expanding the technical infeasibility provision to apply to pneumatic pumps at greenfield sites.
- Clarification that boilers and process heaters are not considered control devices for purposes of the pneumatic pump standards. Nothing has changed within the industry to warrant EPA changing their initial determination.
- Allowing for the certification of technical infeasibility to be provided by a professional engineer (PE) or in-house engineer.
- The various changes and clarifications related to CVS. The commenter (0814-IPAA *et al.*) points out that the proposal inaccurately cites previous EPA conclusions with regard to optical gas imaging (OGI) monitoring of CVS at “no extra cost.” The cited reference makes no mention of cost and that consultants conducting emissions surveys add equipment to monitor at no extra cost.
- Exclusion of “wellhead only well site” or a well site that later becomes a wellhead only well site from fugitive emissions monitoring. The EPA should clarify if the wellhead is disconnected from the associated tank that the well is removed from the monitoring program.
- Extension of the initial monitoring of methane from well sites and compressor stations from 60 to 90 days.
- Clarification of requirements associated with the delay of repair requirements for fugitive methane emissions at well sites and gathering and boosting compressor stations and fugitive VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.
- Revisions to the definition for startup of production as they relate to fugitive emissions at well sites.
- Exclusion of Class I and II Underground Injection Control (UIC) wells as a “well site” for NSPS OOOOa. EPA should also exclude Class II enhanced recovery wells from the monitoring requirements as well.
- Changes to the AMEL provisions.
- Alternative fugitive emissions standards based on equivalent state programs.
- Changes related to onshore natural gas processing plants.
- The “technical corrections and clarifications” present at 86 FR 63168-69.

Commenter (0820-Pioneer) is supportive of keeping the efficiencies in NSPS OOOOa that EPA included in the November 2021 Proposal. This applies to the streamlined leak detection and repair (LDAR) recordkeeping and reporting, PE certification flexibility, and especially the very helpful improvement to the Clean Air Act (CAA) 111(h) AMEL process. These efficiencies reduce unnecessary burden without negative environmental impacts, thus increasing the cost effectiveness of the NSPS OOOOa rulemaking. The commenter strongly urges EPA to provide these changes in the regulatory language of NSPS OOOOb and EG OOOOc as these technical changes are important for compliance with the rule. The commenter believes it is EPA’s intent to

retain these changes for these regulations and respectfully request that the language is included in the forthcoming regulatory language.

Commenter (0836-Domestic Energy Producers Alliance (DEPA)) specifically supported comments provided by 0814-IPAA *et al.*

Commenter (1391-INGAA) generally supports the following amendments to NSPS OOOOa:

- Extending the deadline for conducting initial monitoring from 60 to 90 days for both VOC and methane emissions at all well sites and compressor stations.
- Amending the NSPS OOOOa provisions associated with applications for use of an AMEL for methane work practice standards at well sites and gathering and boosting compressor stations and VOC and methane work practice standards at compressor stations in the transmission and storage segment.
- Finding that state fugitive emission standards for methane and VOCs in California, Ohio, Pennsylvania, and Texas for compressor stations in the transmission and storage segment are “equivalent with, if not better than, the Federal requirements.”
- Aligning the methane standards of NSPS OOOOa with the 2020 Technical Rule to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump.

The commenter (1391-INGAA) notes that all of these amendments made sense when they were done as part of the 2020 Technical Rule for the reasons expressed there, and they support extending these provisions to the transmission and storage segment and to methane emissions.

Commenter (0938-TXOGA) supports the EPA’s reinstatement of the 2020 Technical Rule provisions and states that although they believe that the effort may have been able to be accomplished via direct final rulemaking or under an exception to the Administrative Procedures Act (APA) notice and comment procedures, they state that it is helpful for the Agency to explain why it believes that the amendments are also appropriate for methane. The commenter notes that the emissions points and nature of the emissions are the same as for VOC, which means these provisions should be applied also to methane.<sup>3</sup> The commenter adds that the rulemaking record for the 2020 Technical Rule supports this conclusion.

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<sup>3</sup> According to the commenter: “For example, EPA proposes in its standards for pneumatic pumps to align the requirement of certification of technical infeasibility by a qualified third-party Professional Engineer (PE) with the 2020 Technical Rule. TXOGA had supported this provision in the proposal for the 2020 Technical Rule, which allows this certification by either a PE or an in-house engineer, recognizing that in-house engineers have strong and direct knowledge about site design and control than a third-party PE. See 86 Fed. Reg. at 63,192. TXOGA supports this change and maintains that it should be interpreted to apply for all aspects of the Proposal. This flexibility should be equally applicable for all requirements associated with PE certifications under Quad Oa, Quad Ob, and Quad Oc, consistent with the original Quad Oa 2016 rulemaking, such as closed vent system design. See 81 Fed. Reg. 35,824, 35,883 (June 3, 2016) (“The Agency is convinced that an employee of a facility, who is a qualified professional engineer and who has been licensed by a state licensing board, would be no more likely to be biased than a qualified professional engineer who is not an employee of the owner or operator. The EPA has concluded that the programs established by state licensing boards provide sufficient guarantees that a professional engineer, regardless of whether he/she is ‘independent’ of the facility, will give a fair technical review.”).

Response I-2-1: EPA acknowledges the commenter's support for the proposed standards.

With regards to commenter's suggestions that EPA provide these changes in the regulatory language of NSPS OOOOb and EG OOOOc as these technical changes are important for compliance with the rule, EPA generally agrees and has retained the majority of the elements discussed in the 2021 proposal, which keeps certain aspects of the 2020 Technical Rule, including the corresponding regulatory amendments to NSPS OOOOa. These requirements are being finalized as proposed. For the few areas where EPA is finalizing provisions based on comments received, EPA has discussed these topics in section XI. Significant Comments and Changes to NSPS OOOOa and NSPS OOOO of the preamble to the final rule.

With regards to a commenter's point that EPA inaccurately cites previous EPA conclusions related to OGI monitoring of CVS at "no extra cost," EPA disagrees. In the 2021 proposal EPA stated that:

"We further incorporated the option for OGI monitoring because OGI is already being used for those sites that are subject to fugitive emissions monitoring and the CVS can readily be monitored during the fugitive emissions survey at no extra cost. 85 FR 57405.<sup>4</sup>".

This statement was based on information gathered for the 2020 Technical Rule, where EPA specifically indicated that it did not expect any additional costs associated with OGI monitoring of CVS, where the site was already subject to regular fugitive emissions monitoring requirements. Specifically, EPA stated the following in the 2020 Technical Rule:

"The EPA received comments recommending (1) retaining annual Method 21 as an option and (2) including OGI monitoring as an additional option because OGI is already being used to monitor fugitive emissions components at the well site and the CVS can readily be monitored at the same time.<sup>5</sup>"

With regards to a commenter's suggestions that EPA should clarify if the wellhead is disconnected from the associated tank that the well is removed from the monitoring program, EPA believes the regulatory text is clear on this point. 40 CFR §60.5397a(g)(5) specifies that:

"You are no longer required to comply with the requirements of paragraph (g)(1) of this section when the owner or operator removes all major production and processing equipment, as defined in § 60.5430a, such that the well site becomes a wellhead only well site. If any major production and processing equipment is subsequently added to the well site, then the owner or operator must comply with the requirements in paragraphs (f)(1) and (g)(1) of this section."

As specified in the existing regulatory provisions for NSPS OOOOa, if the well site becomes a wellhead only well site, the fugitive emissions monitoring requirements of 40 CFR §60.5397a(g) do not apply. The wellhead only well site would not be subject to fugitive emissions monitoring

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<sup>4</sup> 86 FR 63162 (November 15, 2021).

<sup>5</sup> 85 FR 57405 (September 15, 2020).

but would have to report the change in status in the annual report as specified in §60.5420a(b)(7)(i)(D):

“For each collection of fugitive emissions components at a well site where during the reporting period you complete the removal of all major production and processing equipment such that the well site contains only one or more wellheads, you must include the date of the change to status as a wellhead only well site. Report the change in status in the annual report as specified in §60.5420a(b)(7)(i)(D).”

## 2.2 Applicability/Scope

Comment: Commenter (0928-American Public Gas Association (APGA)) states that because their members are small systems without access to significant resources to fully analyze complex rulemakings such as this, it is important that the scope of the rule be made as clear as possible. The commenter requests that EPA include the following underlined text in NSPS OOOOa at 40 CFR 60.5365a and in appropriate, corresponding sections of NSPS OOOOb and EG OOOOc (new text indicated by underlined text):

### **§60.5365a Am I subject to this subpart?**

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas Production source category, as defined in § 60.5430, for which you commence construction, modification, or reconstruction.

Another commenter (0815-American Gas Association (AGA)) states that the wording at 40 CFR 60.5365a does not clearly describe the scope of the subpart or answer the question, “Am I subject to this subpart?” Similar to commenter (0928-APGA), this commenter (0815-AGA) states that a small gas utility or cooperative that does not have an environmental lawyer on staff may not understand that the rule applies only to facilities that are located within the Crude Oil and Natural Gas Production source category as defined in 40 CFR 60.5430a, and that they should turn to the definitions section toward the end of the rule to discover that the source category does not include operations inside and including the Local Distribution Company (LDC) custody transfer station, and then understand that the subpart only applies to facilities in the defined source category. The commenters state that clarifying language was added to 40 CFR 60.5365a in the 2020 Policy Rule. At a minimum, the commenter suggests that clarifying language be restored in NSPS OOOOa and included in the new scope provisions of NSPS OOOOb and EG OOOOc so that it is clear to anyone asking, “Am I subject to this subpart?” that facilities inside and including the LDC custody transfer station are not subject to the subpart.

Commenter (0815-AGA) urges EPA to include the following text in 40 CFR 60.5365a and the analogous scope sections of NSPS OOOOb and EG OOOOc: “You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil

and Natural Gas Production source category, as defined in §60.5430a. Facilities located inside and including the LDC custody transfer station are not subject to this subpart.”

Response I-2-2: EPA agrees that, while the definitions section clearly defines the boundaries of the source category, additional clarification in the applicability section of the subpart, in particular with respect to LDC custody transfer, would further help sources to identify if they might be subject to any of the requirements in NSPS OOOOa. Therefore, the final rule includes the following introductory language at 40 CFR 60.5365a:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in §60.5430a, for which you commence construction, modification, or reconstruction after September 18, 2015, and on or before December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

Comment: Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and the Railroad Commission (RRC)) states that the EPA should allow sites that were never subject to or no longer subject to NSPS OOOOa because of the 2020 Policy Rule sufficient time to comply with the NSPS OOOOa reinstated requirements. The commenter explains that the 2020 Policy Rule removed applicability of NSPS OOOOa requirements for transmission and storage facilities and for methane. They add that the congressional overturn of the 2020 Policy Rule and automatic reinstatement of the 2016 rules means that NSPS OOOOa again applies to these sources. The commenter suggests that additional time for compliance should be provided for sources that are not currently in compliance with the proposed requirements but are immediately subject to NSPS OOOOa upon reinstatement.

Response I-2-3: On June 30, 2021, President Joseph R. Biden, Jr. signed into law a joint resolution of Congress adopted under the CRA, disapproving the final EPA rule titled, “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,” 85 FR 57018 (September 14, 2020) (2020 Policy Rule). On that same date, EPA provided initial guidance to stakeholders, in the form of questions and answers, about the effect of the CRA resolution. Within that questions and answers (Q&A) document, EPA stated that “any new, modified, or reconstructed facility that would have been subject to the 2012 or 2016 NSPS (“affected facility”) but for the 2020 Policy Rule will immediately become subject to those NSPS.” Further, EPA stated that “the CRA resolution of disapproval does not explicitly address the deadline by which you must comply with the standards” and “EPA expects owners and operators of regulated sources to take immediate steps to comply with the applicable 2012 and 2016 standards.” See full Q&A document located at [https://www.epa.gov/system/files/documents/2021-07/qa\\_cra\\_for\\_2020\\_oil\\_and\\_gas\\_policy\\_rule.6.30.2021.pdf](https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf).

## 2.3 Well Completions - Hydraulic Fracturing

Comment: Commenter (0577-Kansas Independent Oil & Gas Association (KIOGA)) believes well completions performed in Kansas, and other similar areas, do not meet EPA's definition of hydraulic fracturing for the geologic and engineering reasons provided below. The commenter recommends that the definition in NSPS OOOOa be amended to explicitly exclude conventional wells from the regulation because the work performed does not meet the definition provided in the regulation. The commenter notes that operations in Kansas do utilize pressurized fluids that contain water, proppant, and/or chemicals. However, they explain that the majority of the operations use a process that neither penetrates tight formations like shale or coal, nor require high rate, extended flowback. According to the commenter, most Kansas operations result in little to no flowback from formations with higher quality reservoir properties than shale or coal. The commenter states that ignoring those two facts discounts two thirds of the definition as outlined by 40 CFR 60.5430a. The commenter provides that enforcing this regulation based on "the process of directing pressurized fluids" alone; but not based on the type of formation or subsequent flowback directly ignores the criteria outlined by this regulation. They infer that these two criteria were included in the definition of hydraulic fracturing, as pertaining to this regulation, to distinguish the varying completion styles of small, vertical, conventional drilling targets from large, horizontal, tight, unconventional drilling targets (such as shale and coal).

The commenter (0577-KIOGA) assumes that this distinction was developed due to the difference in potential greenhouse gas emissions from the dissimilar formation types and completion styles. They explain that, while the amount of greenhouse gases emitted from each reservoir type has yet to be quantified, the commenter assumes the greenhouse gas emissions will be proportional to the amount of hydrocarbons produced (*i.e.*, the more oil and gas a well produces has the potential to produce greater amounts of greenhouse gases that well may emit). The commenter reports that the average estimated ultimate recovery (EUR) for vertical wells in Kansas is 20,000-30,000 barrels of crude oil (bbl)/well, where shale wells yield much higher EURs. Per Energy Information Administration (EIA) data, the average EUR is 168,000 bbl/well for an Eagleford shale well and 243,000 bbl/well for an Eastern Bakken well. Based on these numbers, the commenter states that a typical Kansas well will yield about 10 percent of the oil, and theoretically 10 percent of the greenhouse gas, of a typical oil shale well. The commenter provides a table [Table 7 of their comment letter (page 13)] that presents a comparison of typical reservoir and completion parameters for tight shale formations and for conventional formations targeted in Kansas. The commenter notes that many of the terms mentioned in the definition provided in 40 CFR 60.5430a are also included as a comparison between wells drilled in Kansas and by operators targeting tight, unconventional, shale formations.

Commenter (0598-CER) expresses that they continue to advocate that the conventional wells that utilize low pressure, small volumes of water and proppant, and have a short flowback period (*i.e.*, hours or minutes) were not originally intended to be covered in the 2016 NSPS. The commenter recommends that the original definition of "hydraulic fracturing" be maintained from the 2016 NSPS and that the wells that do not meet this definition be exempt from NSPS OOOOa (and NSPS OOOOb, and EG OOOOc). The commenter states that their recommendation is based on the much lower potential to emit (PTE) from wells that do not experience the high-volume, high-pressure fracture stimulation events that are utilized for the unconventional wells.

Response I-2-4: The definition of “hydraulic fracturing” in 40 CFR 60.5430a of NSPS OOOOa is not being reconsidered or amended under this action. NSPS OOOOa defines hydraulic fracturing as follows:

*Hydraulic fracturing* means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

For comments and responses on well completions and associated definitions (including the hydraulic fracturing definition) leading to the inclusion of this definition in the final 2016 NSPS subpart OOOOa rule, see Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 3. Well Completions.

## **2.4 Fugitive Emissions**

### ***2.4.1 Low Production Wells***

Comment: Commenter (0458-MDE) supports enhanced monitoring for low-production well sites. The commenter suggests the smaller wells could have as much, or more, fugitive and vented emissions as they are less monitored and maintained.

Conversely, commenters (0577-KIOGA, 0803-Ohio Oil & Gas Association (OOGA), 0824-Wyoming Department of Environmental Quality (WDEQ), 0464-Muskegon Operating Company LLC (MOPC)) object to the proposal to repeal the amendments in the 2020 Technical Rule that exempted low production well sites from monitoring fugitive emissions under the NSPS (86 FR 63118).

Commenter (0803-OOGA) urges the EPA to retain the exemption for low-production wells. The commenter states that a significant portion of the more than 61,000 wells in Ohio meet the definition of a low production well (*i.e.*, produce at or below 15 barrels of oil equivalent (boe)/day) and, in fact, produce on average far less than 15 boe/day. Notwithstanding the commenter’s objection to removing the exemption for low production wells, the commenter contends that the EPA’s proposed site-level baseline methane estimate methodology to determine whether a well site is subject to the fugitive emissions monitoring requirement is flawed for several reasons.

Commenter (0810-Petroleum Alliance of Oklahoma (PAO)) recommends that the EPA first determine if marginal well emissions warrant regulation. The commenter explains that when EPA developed its NSPS OOOOa regulation for oil and gas, it had no emissions profile for marginal/low production wells; however, EPA proceeded to regulate them with a limited data set. Currently, the commenter notes that the EPA still has a limited data set that does not fully characterizes these types of wells. The commenter notes that the Department of Energy (DOE) is conducting a study to better characterize emissions from these types of wells (expected to be publicly available in early 2022). The commenter states that Executive Order 13990 requires the Federal Government, “...be guided by the best science and be protected by processes that ensure

the integrity of Federal decision-making.” As such, the commenter recommends that the EPA defer regulating marginal/low production wells until this report is available for review or collect additional data to fully determine the emissions profile of these types of wells, determine if requirements are needed, and if needed, develop an appropriate regulatory program.

Commenter (0763-TCEQ/RRC) suggests that removing the exemption for low producing wells from quarterly fugitive emission monitoring in NSPS OOOOa could result in tens of thousands of additional affected facilities and/or projects establishing PTE below affected source emission levels. The commenter adds that changing this requirement may also result in some facilities becoming an affected facility retroactively.

Commenter (0824-WDEQ) states that the proposed rule repeals amendments to the 2016 NSPS OOOOa in the 2020 Technical Rule that exempted low production well sites from monitoring fugitive emissions. The commenter adds that it also requires low production well sites to undertake semiannual monitoring of VOC and methane emissions. Furthermore, under EPA's proposed NSPS OOOOb and EG OOOOc requirements, the commenter notes that well sites with total site-level baseline methane emissions of 3 tons per year (tpy) or greater would trigger requirements for quarterly OGI or EPA Method 21 monitoring. They add that these requirements would affect many stripper wells in Wyoming (defined by the Wyoming Oil and Gas Conservation Commission (WOGCC) as wells that produce an average of 15 bbl or less per day) and some very small-scale, independent well site operations that strictly operate on a single owner's private property. According to the WOGCC, Wyoming has approximately 6,524 stripper wells. The commenter is concerned about the potential adverse economic impacts of these proposed regulations upon individual operators and the greater economy of the State of Wyoming and states that the economic impacts outweigh the indeterminate and potentially marginal environmental benefits of the proposal. They add that the cost of compliance with these requirements is simply unworkable for many smaller operators in Wyoming and some have already expressed concerns to WDEQ that they will go out of business due to the proposed requirements. The commenter (0824-WDEQ) suggests that the EPA prematurely proposed these requirements for marginal well sites without having thoroughly evaluated the emissions or the costs to control those emissions from those marginal sites. The commenter notes that they are aware that at least one study is underway to evaluate methane emissions from marginal wells,<sup>6</sup> and there may be others. If the study's findings demonstrate that these methane emission contributions from low production well sites do not contribute in any significant manner, it is imperative that EPA consider these findings and provide appropriate exemptions.

Another commenter (0464-MOPC) opposes the proposed regulations modifying NSPS OOOOa. The commenter states that the changes to the rules will have significant detrimental impacts on their operations, costs, overhead, reserve recovery, plugging costs, and employment. The commenter notes that every increase in cost directly jeopardizes their ability to produce marginal wells. They state that marginal wells are not a significant source of methane. Emissions from a well are proportionate to the volume of oil and/or gas produced. The commenter explains that marginal wells produce significantly less emissions due to the fact that they are marginal producers of oil and gas. According to the commenter, emissions from their wells are much

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<sup>6</sup> "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" (under review), U.S. Department of Energy, National Energy Technology Laboratory: <https://netl.doe.gov/node/9373>.



lower than those emitted from high volume wells produced by larger companies. As a responsible operator, the commenter states that they have acted to voluntarily minimize their emissions in a prudent manner that meets standards they can afford. The commenter adds that it is unfair and unwise to treat small operators with marginal wells in the same manner as larger producers. The commenter suggests that marginally producing wells (15 BOEPD/90 MCFPD or less) be exempt from EPA rules because the emissions are insignificant and the rules would be uneconomic. They further suggest that there needs to be a regulatory "off ramp" for wells such as theirs that are low producers. The commenter supports exempting marginal, low production wells from the proposed regulations.

Commenter (0464-MOPC) states that, if the EPA continues on its course to regulate emissions from marginal wells it will:

- unnecessarily increase cost of operations, cause the premature plugging of marginal wells, and significantly add to the number of orphan wells in the State of Michigan;
- bankrupt small businesses and cause irreversible economic harm to the oil and gas community;
- cause the waste of our natural resources by forever foreclosing the production of marginal wells, which is in contravention of our state laws which require the prevention of waste; and
- increase our country's reliance on foreign oil and gas.

Commenters (1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*) recommend that the EPA consider the small, low-emitting nature of Pennsylvania and New York conventional oil and gas production before imposing any additional requirements in the NSPS OOOOa (and NSPS OOOOb and EG OOOOc) revisions. In summary, the commenter indicates that EPA takes a one-size-fits-all, industry-wide approach to determining whether additional, and potentially far more restrictive requirements, should be imposed on oil and gas producers. The commenter explains that their members are primarily small, family-owned businesses and individuals operating low-producing oil and gas wells. According to the commenter, profound differences exist in the scale, production, design, and layout of their members conventional operations, as compared to the large, high-volume unconventional gas wells being drilled for several miles into deep geologic formations.

Response I-2-5: In response to comments that are concerned about the requirements for small well sites, EPA points out that it believes most of these well sites would be existing sources, and therefore not subject to NSPS OOOOa standards. However, these sources would be subject to the EG OOOOc requirements, where quarterly AVO monitoring was proposed in the 2022 supplemental proposal. If the sources in question are modified, they would also be subject to quarterly AVO under the proposed NSPS OOOOb.<sup>7</sup>

EPA acknowledges comments supporting monitoring for low-production well sites, as these sites can have large leaks that could go unnoticed without regular monitoring. The DOE Study

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<sup>7</sup> 87 FR 74718.

specifically indicated that two of the top 10 largest leaks found were located at the wellhead.<sup>8</sup> In 2021, EPA proposed to rescind the 2020 Technical Rule that exempted low-production well sites from fugitive emissions monitoring, as this exemption was not supported by the record for that rule, or by additional information reviewed since then. EPA discussed in the 2021 proposal the uncertainty around the connection between fugitive emissions and production levels, and concluded at that time that information does not show a link between production and emissions, and therefore no production level would support any exemption from fugitive monitoring.<sup>9</sup>

Therefore, in the 2021 proposal, EPA moved away from a production-based threshold and proposed instead monitoring based on site-level methane baseline emissions estimated through equipment/component count emission factors. As stated in the November 2021 proposal, EPA does remain mindful about how the fugitive emissions monitoring requirements will affect small businesses. EPA specifically sought comment on the 2021 proposed approach to determine if there were other regulatory alternatives and additional information that would warrant considering a subset of sites differently based on a potentially different emissions profile, production levels, equipment onsite, or other factors.

The EPA examined data provided through an information collection request (ICR) distributed in 2016, data provided on equipment/component counts in relation to the October 15, 2018, proposed reconsideration of NSPS OOOOa from independent producers (many of whom are small businesses), data provided through comments on the November 2021 proposal from independent producers, and data contained in the U.S. DOE marginal well study to determine if a subset of well sites with major production and processing equipment should be considered differently. Consistent with comments received on previous rulemakings, the EPA received comments on the November 2021 proposal expressing that emissions from a well are proportionate to the volume of oil and/or gas produced.<sup>10</sup> Commenters also referenced the DOE Study. However, that marginal well study (now available) concludes that the frequency and magnitude of emissions from well sites are more strongly correlated with equipment counts, not production rates.<sup>11</sup> Further, this study broke down emissions by site size and production levels and found that the smallest emissions rates were from the second production level bin (2 barrels of oil equivalent per day (boe/day) to 6 boe/day) and not the sites with production less than 2 boe/day. Another study issued in April 2022 by Omara, et al. concludes that approximately half of the methane emissions emitted from well sites in the U.S. comes from low production well

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<sup>8</sup> Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. <https://doi.org/10.2172/1865859>. See Table 2 of the study for details on the top 10 emissions sources identified.

<sup>9</sup> 86 FR 63159.

<sup>10</sup> See Document ID No. EPA-HQ-OAR-2021-0317-0464.

<sup>11</sup> Section 5.2.1 of the study concludes, “The correlation between major equipment counts and site emission frequency (expressed as the number of detected emissions per piece of major equipment, i.e., not absolute count of emissions), was strong with the categorical site ‘size’ variable and moderate (positive) with the numeric equipment count. Among evaluated numeric variables, site equipment counts also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.” See Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. <https://doi.org/10.2172/1865859>. page 19.

sites (15 boe/day or less production rates).<sup>12,13</sup> However, the EPA notes that this study is not limited to fugitive emissions, and the overall impacts on emissions reductions achieved under NSPS OOOOa (and NSPS OOOOb and EG OOOOc), if these rules are finalized as proposed, would target the emissions reported in that study as a whole. Therefore, the EPA does not have compelling information that suggests production levels should provide the basis for consideration of different fugitive emissions requirements for well sites.

The EPA is therefore finalizing the proposed (86 FR 63158-63159) removal of the exemption of low production well sites from fugitive VOC emissions monitoring, thereby restoring the semiannual monitoring requirement established in the 2016 NSPS OOOOa.

#### ***2.4.2 Gathering and Boosting Station/Compressor Station Monitoring***

Comment: Commenter (0755-Texas Pipeline Association (TPA)) recommends that fugitive emissions monitoring at compressor stations only be required on a semi-annual basis. The commenter does not support or concur with EPA's proposal to increase the frequency of required fugitive emissions monitoring in this proposal to quarterly at compressor stations, including gathering and boosting compressor stations.<sup>14</sup> They contend that a requirement for more frequent monitoring would be unduly burdensome, given that one pipeline system could have numerous compressor stations that are often located in remote areas. In addition, they state that the resources (both personnel and equipment) to comply with survey requirements may be limited, a concern that they say that the EPA itself acknowledged in the preamble for the initial NSPS OOOOa proposal.<sup>15</sup> Moreover, the commenter states that the leak rate in the gathering and boosting industry segment is particularly low.<sup>16</sup> The commenter adds that, as recently as September 2020, EPA concluded that semiannual monitoring was sufficient. According to the commenter, they do not believe that, little more than a year later, EPA has uncovered a sufficient basis to reject that conclusion and to cut in half the required monitoring interval. The commenter urges EPA to retain the current requirement of semiannual monitoring for fugitive emissions at compressor stations, including gathering and boosting compressor stations.

Similarly, commenter (0923-Lambda Energy Resources LLC (Lambda)) believes it is overly burdensome to require quarterly compressor monitoring in respect to surveys and record keeping. The commenter notes that the value of increased monitoring to reduce small amounts of methane and VOCs does not offset the associated expense and manpower required to fulfill the proposed regulations. The commenter suggests that perhaps a baseline for compressor stations could be undertaken as a similar proposal for less than 3 tpy well sites to determine future requirements of a particular site.

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<sup>12</sup> Omara, M., Zavala-Araiza, D., Lyon, D.R. et al. Methane emissions from US low production oil and natural gas well sites. Nat Commun 13, 2085 (2022). <https://doi.org/10.1038/s41467-022-29709-3>.

<sup>13</sup> The EPA notes that Omara et al. analyzed data from offsite measurements of methane emissions from well sites. These measurements would include methane from any leak, venting, flaring, or other source onsite and, therefore, conclusions from this study cannot be directly applied to the specific fugitive sources covered by this action.

<sup>14</sup> See 86 FR 63158-59, 63169, 63174 (Nov. 15, 2021).

<sup>15</sup> See 80 FR 56643 (Sept. 18, 2015) (noting possible logistical challenges in securing the services of qualified monitoring personnel and possible shortages of monitoring equipment).

<sup>16</sup> See data collected at Docket ID No. EPA-HQ-OAR-2017-0483-0027.

Commenter (0763-TCEQ and RRC) suggests that changing monitoring frequency for the transmission and storage segments from semiannual to quarterly creates confusion with the other actions taken in 2021 regarding NSPS OOOOa as these facilities have transferred back and forth between affected facility status due to policy changes within the existing NSPS OOOOa. Proposed subclassification of compressor stations within the NSPS will create the same confusion.

Response I-2-6: As stated in the December 2022 supplemental proposal, the analyses EPA conducted for NSPS OOOOb and EG OOOOc confirms that quarterly monitoring remains both achievable and cost-effective for compressor stations, and several state agencies have rules that require quarterly monitoring at compressor stations.

The cost analysis conducted for the 2021 proposal was a comprehensive evaluation of emissions, reductions, and costs associated with various leak detection and repair programs, which firmly established that the cost effectiveness of quarterly monitoring for compressor stations is reasonable.<sup>17</sup> The 2021 proposal established that BSER for reducing methane and VOC emissions from all compressor stations, including gathering and boosting stations, transmission stations, and storage stations was quarterly monitoring. In the 2022 supplemental proposal, EPA retained the proposed quarterly OGI (or EPA Method 21) monitoring requirement for fugitive emissions components affected facilities located at compressor stations, based on finding no reasons to change this frequency.

Therefore, based on the reasoning provided in the November 2021 proposal that the EPA lacked justification and erred in revising the VOC monitoring frequency for gathering and boosting compressor stations from quarterly to semiannual and the cost-effectiveness of control for quarterly monitoring, the EPA is finalizing the restoration of the quarterly monitoring requirement for gathering and boosting compressor stations, as established in the 2016 NSPS OOOOa.

### ***2.4.3 Well Site Definition***

Comment: Commenter (0817-GPA) strongly supports EPA's proposal to maintain the definition of "well site" that EPA adopted in the 2020 Technical Rule, which excludes third-party equipment from the flange immediately upstream of the custody meter assembly and equipment.<sup>18</sup> The commenter states that they outlined previously for EPA that including ancillary midstream equipment, such as meters, within the definition of a "well site," is not feasible and creates significant problems for midstream operators.<sup>19</sup>

The commenter (0817-GPA) explains that the principal reason is simple: most wellhead gathering metering systems are located near or on the producer's well pad but are owned and

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<sup>17</sup> 86 FR 63196 (Nov. 15, 2021).

<sup>18</sup> See 86 FR 63165 (Nov. 15, 2021).

<sup>19</sup> See, e.g., GPA Comments, Docket No. EPA-HQ-OAR-2010-0505-6881 (Dec. 4, 2015) at 8-12; GPA Supplemental Comments, Docket No. EPA-HQ-OAR-2010-0505-7552 at 1-3 (Apr. 15, 2016); GPA Comments, Docket No. EPA-HQ-OAR-2010-0505-6881 (Dec. 4, 2015) at 8-12; GPA Comments, Docket No. EPA-HQ-OAR-2017-0346-0406 (Dec. 8, 2017) at 4-9.

operated separately by a midstream company, not the producer. The commenter adds that a single midstream company could have hundreds of meters on the property of third-party producers. Each company lacks operational control over the other's equipment for purposes of monitoring, repair, and replacement. According to the commenter, midstream operators cannot allow producers to access or repair a gas gathering meter due to its crucial role in calculating the gas accepted by the gathering company and the related revenue accounting.

Commenter (0539-Alaska Oil and Gas Conservation Commission (AOGCC)) notes that EPA states in the proposal that an operator's responsibility ends at the flange upstream of the custody transfer meter.<sup>20</sup> In Alaska, production must be metered prior to leaving the lease/unit and that the operator is responsible for the custody transfer metering system.

The commenter (0817-GPA) further states that before the changes made in the 2020 Technical Rule, the "well site" definition included co-located midstream equipment with the upstream producer's equipment. With respect to midstream operators, the commenter notes that their co-located equipment would have been subject to new NSPS OOOOa LDAR requirements whenever a third-party producer constructed a new well, re-fractured an existing well, or took any other action that increased emissions at the well site. The commenter adds that the EPA recognized these practicalities in redefining "well site" in the 2020 Technical Rule—and the commenter supports the proposal to use the 2020 Technical Rule's definition of "well site" for methane regulations.

Response I-2-7: EPA acknowledges the commenter's support and has finalized the definition of well site as proposed. Specifically, well site is defined at 40 CFR 60.5430a:

*Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located the well site (e.g. centralized tank batteries). Also, for the purposes of the fugitive emissions standards at §60.5397a, a well site does not include:

- (1) UIC Class II oilfield disposal wells and disposal facilities;
- (2) UIC Class I oilfield disposal wells; and
- (3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Comment: Commenter (0539-AOGCC) states that it is unclear if a well test separator at a well site would qualify as major production and processing equipment. The definition of major production and processing equipment does include separators, but the commenter asked whether the intent is to cover all separators, including well test separators that only accommodate a well or two at a time and the streams are recombined before production leaves the well site to head to

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<sup>20</sup> See 86 FR 63165 (Nov. 15, 2021).

a central processing facility, or whether it is supposed to only apply to larger process related separators.

Commenter (0539-AOGCC) states drilling a new well or fracking or refracking a well on a well site appears to trigger the entire well site, and any and all processing facilities located downstream of the well site, instead of just the impacted well(s), becoming subjected to the new regulations. This could lead to operators not conducting such work on a marginal well due to the fact that doing so would appear to dramatically increase their regulatory burden for the entire field. Also, it is not clear if the new well trigger only applies if it is a new grassroots well or if it applies if an existing well is sidetracked or a lateral is added.

Response I-2-8: The definition of major production and processing equipment in NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc is not limited to a particular type of separator. The definition of major production and processing equipment covers all types of separators. An existing well site would become subject to NSPS OOOOb if it meets the modification criteria in 40 CFR §60.14, or an existing well is hydraulically fractured, or when an existing well is hydraulically refractured.

Comment: Commenter (0425-Darrah Oil, 0539-AOGCC) believes that Class II enhanced oil recovery (EOR) wells should have the same exemption considerations as Class II disposal wells.

Commenter (0539-AOGCC) refers to the proposal where EPA states that UIC Class I wells and UIC Class II disposal wells are excluded due to negligible fugitive VOC and methane emissions. (86 FR 62125). By the same logic, the commenter believes that UIC Class II EOR water injection wells should also be excluded.

Commenter (0425-Darrah Oil Company, LLC (Darrah)) adds that, as a company that is studying Class VI wells for carbon dioxide sequestration, the commenter would encourage all disposal wells to be exempt to further the EPA's goal that disposal wells help achieve.

Response I-2-9: As described in the 2021 proposal<sup>21</sup> (and consistent with the 2020 Technical Rule for NSPS OOOOa where EPA amended the definition of a well site), EPA made it clear that for purposes of the fugitive emissions standards, a well site does not include: (1) UIC Class II oilfield disposal wells and disposal facilities; (2) UIC Class I oilfield disposal wells; and (3) the flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange. These proposed exclusions were not changed in the 2022 Supplemental Proposal, as EPA continues to believe that fugitive emissions from UIC Class I oilfield disposal wells and UIC Class II oilfield wastewater disposal wells are negligible, as previously stated.<sup>22</sup>

As far as the concerns regarding UIC Class II EOR water injection wells, EPA agrees with the commenter that fugitive emissions are low. As currently defined in 40 CFR §144.6, EOR water injection wells are already included, specifically named under 40 CFR §144.6(b)(2):

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<sup>21</sup> 86 FR 63165 (November 15, 2021).

<sup>22</sup> 85 FR 57407 (September 15, 2020).

(b) Class II. Wells which inject fluids:

(1) Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.

(2) For enhanced recovery of oil or natural gas; and

(3) For storage of hydrocarbons which are liquid at standard temperature and pressure.

#### ***2.4.4 Wellhead Only Well Sites***

Comment: Commenter (0810-PAO) states that the EPA is proposing to exclude from fugitive emissions monitoring a well site that is or later becomes a “wellhead only well site,” which the 2020 Technical Rule defines as “a well site that contains one or more wellheads and no major production and processing equipment.” The 2020 Technical Rule defined “major production and processing equipment” as including reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. The commenter supports the EPA’s November 2021 Proposal that follows the 2020 Technical Rule.

Similarly, commenter (0797-North Dakota Department of Environmental Quality (NDDEQ) and North Dakota Industrial Commission (NDIC)) agrees with EPA’s proposal that “wellhead only” well sites be excluded from fugitive emissions monitoring based on considerable research and rationale already established in the 2016 NSPS OOOOa rulemaking as well as the 2020 Technical Rule. The commenter also agrees with the November 2021 Proposal to exclude well sites from fugitive emissions monitoring upon those sites becoming wellhead only well sites as provided in the 2020 Technical Rule. According to the commenter, their own experience supports EPA’s conclusion that emissions from these sources are “extremely low.”<sup>23</sup> The commenter notes that North Dakota (which they have knowledge of) has only observed a handful of wellhead only well sites with fugitive emissions, and it appears that in those rare cases that the emissions were more a result of operator error. They add that they believe that the safety risk alone precludes any widespread issue of fugitive emissions from these sites.

Response I-2-10: EPA acknowledges the commenter’s support and has finalized this provision as proposed.

#### ***2.4.5 Initial Monitoring for Well Sites***

Comment: Commenter (0810-PAO) states that the EPA is proposing to further amend the 2016 NSPS OOOOa to extend the deadline for conducting initial monitoring from 60 to 90 days for monitoring both VOC and methane fugitive emissions at all well sites and compressor stations

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<sup>23</sup> See 80 FR 56611 (Sept. 18, 2015).

(except those on the Alaska North Slope provided elsewhere in the November 2021 Proposal). The commenter supports the November 2021 Proposal that follows the 2020 Technical Rule.

Response I-2-11: EPA acknowledges the commenter's support and has finalized this requirement as proposed.

#### **2.4.6 Repair Provisions**

Comment: One commenter (0782-Berkshire Hathaway Energy Company (BHE)) supports reconciling NSPS OOOOa delay of repair regulatory text consistent with the 2020 Technical Rule. The commenter recommends delay of repair text be amended to address the delay necessary when parts are unavailable, an issue that will be especially important for existing sources. Commenter (0782-BHE) supports updates to delay of repair provisions in the 2020 Technical Rule to NSPS OOOOa and reconciling that regulatory text for transmission and storage and upstream operations.

For NSPS OOOOa (and NSPS OOOOb and EG OOOOc), the commenter (0782-BHE) notes that the EPA requested feedback on whether to allow delay of repair due to parts availability. The commenter recommends that EPA include delay of repair provisions for infrequent circumstances when parts availability extends the timeline for repair. The commenter explains that, although such delays will still be infrequent, allowing delay of repair for parts availability is even more imperative for existing sources, because longer lead times, special fabrication, *etc.* are more likely for legacy parts from existing equipment than new sources. Without this delay of repair provision, if part delivery exceeds current delay of repair allowances, the commenter states that operators may be placed in an untenable conflict with federal requirements – *i.e.*, shutting down compressors or entire compressor stations (and compromising reliable natural gas delivery and thus conflicting with the operator's Federal Energy Regulatory Commission (FERC) Certificate), or meeting the FERC obligation (*i.e.*, equipment not shut down to await the part and repair) and thus not meeting EPA compliance requirements.

Commenter (0782-BHE) provides that previous comments submitted to EPA by INGAA<sup>24</sup> and others provide examples of parts availability issues. The commenter notes that, in their experience, the likely parts are large, unique valves used for compressor isolation or isolating sections of a facility or pipeline. These valves are not standard items and come in many configurations. The commenter explains that, given the size and unique specifications of each valve, they contend that it is not practical or economical to maintain a significant inventory of such items. They add that such items may require special fabrication with lead times of many months, and thus may not conform to the current delay of repair provisions. According to the commenter, recent supply chain issues provide another example of an unforeseen circumstance that may arise that affects parts availability and the need for a related delay of repair provision.

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<sup>24</sup> EPA Docket ID No. EPA-HQ-OAR-2010-0505-4104 (Nov. 22, 2011) (INGAA's comments on proposed Subpart OOOO).



The commenter reports that there are EPA<sup>25</sup> and state examples<sup>26</sup> where such provisions have been included in LDAR programs. The commenter expresses support for a similar provision in the EPA methane regulations. As an example, the commenter describes a recently identified a leak on a 16-inch valve. Upon investigation, they determined that repair (*e.g.*, replacing sub-components of the large valve) was not possible and an exact replacement valve could not be ordered because the valve was obsolete. Investigation into a new replacement indicated a lead time on the order of at least 18 weeks. Without delay of repair provisions, the commenter states that a maintenance shutdown would occur in the interim. To maintain safety and reliability, delay due to “parts availability” is needed for this situation. Upon receipt of the part, if the process is operating, the repair will need to be completed when the process is next blown down for maintenance.

Commenter (0782-BHE) states that the EPA requested feedback on documentation required for a parts-based delay of repair. The commenter recommends that the required recordkeeping follow current NSPS OOOOa criteria, where the operator documents the delay basis and repair schedule. For example, purchase orders and other documentation (as needed) on order and delivery dates would support delay due to parts availability. These records would be maintained by the operator and made available to the applicable regulatory agency upon request.

Commenter (0782-BHE) adds that the EPA also requested feedback on the repair schedule when parts are received. The commenter suggests that no special regulatory text is needed because the repair schedule could follow the current NSPS OOOOa criteria. Under such criteria, a repair is completed within 30 days of receiving the part if feasible, but may be delayed if warranted by circumstances, *e.g.*, repair can be delayed until the next scheduled blowdown for maintenance if a blowdown is required to complete the repair.

Similarly, commenter (0815-AGA) states that the EPA must allow for the lead times needed to obtain certain types of parts (supports INGAA comments on this issue). They add that operators should not be penalized for circumstances they do not control, and state that imposing penalties will not reduce emissions where a repair simply cannot be performed until a part is received.<sup>27</sup> The commenter requests that EPA provide in the regulatory text for revised NSPS OOOOa and new NSPS OOOOb that where no shutdown or blowdown is needed, the operator should repair the leak within 30 days after receiving the parts. The commenter supports that where a repair requires a shut down or blowdown, the regulatory text should allow the repair to be performed during the next scheduled shutdown for maintenance after receipt of the requisite parts, not to exceed two years. Again, the commenter states that this will avoid unnecessary blowdown emissions.

**Response I-2-12:** Consistent with the delay of repair provisions related to fugitive emissions from equipment located at well sites and compressor stations, EPA is amending 40 CFR

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<sup>25</sup> 40 CFR, §60.482-9a(e)

<sup>26</sup> CCR 1001-9, Colorado Department of Public Health and Environment, Regulation Number 7, Part D, Section I.L.5 (Repair and Monitoring) (which allows a repair to be delayed if parts are unavailable or for other good cause); Md. Code Regs. 26.11.41.03.A(9)(c)(i) (allowing delay of repair if parts or equipment need to be ordered and delivered).

<sup>27</sup> INGAA Comments, section IV.C.

60.5397a(h)(3) to allow the delay of repairs due to the lack of availability of parts in some circumstances. NSPS OOOOa has been revised to allow for delay of repair due to unavailability of parts if replacement parts are necessary and cannot be acquired within the repair timeline if either replacement part supplies have been depleted and replacement part supplies had been sufficiently stocked before the supplies were depleted or a replacement part requires custom fabrication. Replacement parts must be ordered within 10 calendar days after the first attempt at repair. The repair must be completed within 30 calendar days of receipt of the replacement parts or during the next scheduled shutdown for maintenance after the parts are received (if the repair requires a shutdown). As the EPA was considering provisions allowing for delay of repair due to parts unavailability for sources regulated under NSPS OOOOb and EG OOOOc, the EPA found that the supplemental information submitted and reasoning for allowing delay of repair due to parts unavailability under NSPS OOOOb and EG OOOOc is equally applicable to sources regulated under NSPS OOOOa and, for that reason, is also including the provision in 40 CFR 60.5397a(h)(3).

Comment: Commenters (0817-GPA, 0815-AGA, 1391-INGAA, 0810-PAO, 0755-TPA) specifically support the November 2021 Proposal to allow delays of repair until the next scheduled maintenance shutdown.

Commenter (1391-INGAA) states that, as EPA notes, these maintenance shutdowns occur on a regular schedule, and it makes sense to do the repairs during these shutdowns to avoid unnecessary methane venting and disrupting the reliability of gas transmission.

Comment (0817-GPA) supports EPA's November 2021 Proposal to extend the 2020 Technical Rule "delay of repair" provision, which provides that where repairs are technically infeasible, they should be made during the next scheduled compressor station shut down for maintenance.<sup>28</sup> Previously, the commenter explained that NSPS OOOOa had required repairs to be made during the next scheduled compressor shutdown or after a planned vent blowdown.<sup>29</sup> As the commenter notes that they previously explained in comments and a March 2017 white paper, requiring the repair or replacement of components during a planned vent blowdown can prolong natural gas supply disruptions, jeopardize safety, and potentially release more methane emissions than would be avoided by repairing or replacing a leaking component.<sup>30</sup>

Commenter (0755-TPA) supports EPA's proposal to make clear that completion of delayed repairs at compressor stations under NSPS OOOOa need only be completed during a scheduled maintenance shutdown, not the next shutdown of any kind. The commenter explains that shutdowns can occur for many different reasons, and a shutdown that is not scheduled for maintenance purposes can be a highly inappropriate occasion for conducting or completing repairs. They add that some planned shutdowns do not occur for maintenance reasons, last for a very short time, and are made on short notice. The commenter states that it would be unreasonable, and unworkable in practice, to require that repair personnel be mustered, and

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<sup>28</sup> See 86 FR 63164 (Nov. 15, 2021).

<sup>29</sup> See 83 FR 10628, 10638 (Mar. 12, 2018).

<sup>30</sup> See, e.g., GPA Comments, Docket No. EPA-HQ-OAR-2017-0346-0406 (Dec. 8, 2017) at 9-11; GPA & INGAA, The Delay of Repair Obligations in 40 C.F.R. § 60.5397a(h)(2) Create Compliance Issues that Need to be Addressed Through Regulatory Revisions (Mar. 2017).

repairs be made during these events. In addition, they note that requiring complicated repairs to be made in these circumstances would disrupt normal operations more than would otherwise be the case and thus would disrupt production and transmission activities by delaying the unit's return to normal service. Similarly, they contend that it would be unreasonable to require repairs to be made where a leak was detected shortly before a scheduled shutdown, as it might not always be possible or feasible to locate appropriate repair personnel and/or parts in a timely manner given the short notice that would be involved. Again, the commenter states that requiring repairs to be completed during such a shutdown could greatly lengthen the shutdown, causing unnecessary disruption to natural gas supply. Accordingly, the commenter concludes that it is appropriate for EPA to clarify that completion of delayed repairs at a compressor station is required only during a scheduled compressor station shutdown where maintenance activities have been scheduled. According to the commenter, this represents a reasonable accommodation of the issues expressed above and would align the oil and natural gas NSPS more closely to the delay-of-repair provisions in other NSPS (*e.g.*, Subpart VVa).<sup>31</sup>

Response I-2-13: EPA acknowledges the commenters' support for the provisions to allow delay of repair (where applicable) until the next compressor station shutdown for maintenance. The final rule includes this provision as proposed.

## **2.5 Alternative Means of Emissions Limitation (AMEL)**

Comment: Commenter (0938-TXOGA) states that the AMEL process is critical to promoting innovation in the sector and should be further improved and streamlined. The commenter notes that the EPA highlights that a key theme from the roundtables that it held in preparation for this rulemaking was “improving and streamlining the EPA’s AMEL [alternate means of emissions limitation] process, such as by structuring it so it could apply broadly rather than on a site-by-site basis.”<sup>32</sup> The commenter adds that they agree with EPA’s statements that the AMEL provisions were and continue to be available for the aspects of the rule that were affected by the CRA resolution. In addition to other legal bases that apply to all of the CRA-affected provisions, the commenter states that the AMEL provisions are akin to a “general provision” and apply without regard to any particular pollutant or segment of the source category, and thus, there should be no question that they continue to be available for companies to utilize and for EPA to approve through the established process. Thus, the commenter agrees with EPA’s decision to clarify the continued applicability and availability of the AMEL provisions for methane emissions, including the amendments made in the 2020 Technical Rule.

On a forward-looking basis and given that: (1) EPA recognizes that it is the “technical innovations [that] have produced a range of technologies and best practices to monitor, eliminate[,], or minimize these emissions, which in many cases have the benefit of reducing multiple pollutants at once and recovering saleable products;”<sup>33</sup> and (2) such “technologies and best practices have been deployed by individual oil and natural gas companies,”<sup>34</sup> the commenter (0938-TXOGA) states that the AMEL process provides one of the most promising opportunities

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<sup>31</sup> 40 CFR § 60.482-9.

<sup>32</sup> 86 FR 63146.

<sup>33</sup> *Id.* at 63114.

<sup>34</sup> *Id.*

to create step changes in emissions reduction and improvement. The commenter states that they appreciate EPA's efforts to standardize the process and encourages EPA to ensure that the process is streamlined enough that the burden on both the regulators and those who seek to deploy innovative technologies is not overly burdensome—as that will ultimately be counterproductive to the goal of achieving technological advancements.<sup>35</sup> Specifically, the commenter suggests the following as examples of improvements to EPA's AMEL standards:

1. EPA could publish a list of available technologies for all operators, not just for specific operators seeking AMEL. In addition, EPA can enhance transparency and further drive innovation throughout the sector by making available information on how it evaluates alternate technologies, including the flexibility available.
2. EPA should allow companies to replace OGI surveys with an alternate technology with equivalent effectiveness (subject to (3), below).
3. EPA should avoid a point-by-point "equivalency" requirement for alternate technologies. We do not consider that to be required by the regulations, and such a requirement would be counterproductive to fostering innovation and step-changes in technology. For example, some alternative technologies may provide benefits in identifying large leak events sooner than an OGI schedule would dictate, and this could and should be allowed. The equivalence evaluation in such a case would be based on the emissions reduction capability rather than a leak-by-leak evaluation.
4. When a method is approved for a specific technology, all companies should be allowed to use the same method without the need to pursue a formal process for a new AMEL. In other words, if an AMEL is approved for a particular affected facility, streamlining of process should be available for other companies. This is consistent with the original AMEL approach, which allowed technology companies to apply for nationwide AMEL.

Commenter (0740-Utah Petroleum Association (UPA)) states the November 2021 Proposal discusses state fugitive emission standards that EPA previously approved including standards for Utah, "EPA is now proposing that all well sites and compressor stations located in and subject to the specified State regulations in 40 CFR 60.5399a may utilize these alternative fugitive emissions standards for both methane and VOC fugitive emissions."<sup>36</sup> The commenter supports retaining this approval.

Commenter (0755-TPA) supports the proposal to extend the rules regarding AMEL applications to all applicants seeking an AMEL for methane and VOC work practice standards in NSPS OOOOa. The commenter notes that in the 2020 Technical Rule, EPA recognized the benefits of streamlining the requirements pertaining to applications to use AMEL for VOC emissions from, inter alia, reciprocating compressors and gathering and boosting compressor stations. The commenter notes that the EPA now proposes to apply those provisions to work practice

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<sup>35</sup> According to the commenter: "We highlight as an example of success in this area EPA's Plantwide Applicability Limit (PAL) regulations under 40 CFR § 52.21(aa). EPA undertook an innovative permit initiative in the 1990s and ultimately issued regulations intended to standardize and streamline the process in 2002. Since that time, numerous PAL permits have been issued and significant emissions reductions have occurred that would not otherwise have happened. The key to the success of that program was that the regulations standardized the process but also provided EPA and states the flexibility to adapt as long as core criteria were met."

<sup>36</sup> See Proposal p. 63167 and 40 CFR §60.5399a(n).

standards for methane emissions as well. The commenter states that they support this proposal because it is appropriate not to unduly limit the category of those who can submit AMEL use applications, whether the pollutant at issue is VOC or methane. If applicable information requirements and reduction demonstrations are met, as provided by the rules, then it is beneficial to increase flexibility by allowing submission of applications by “any person,” including but not limited to states and political subdivisions (included in the definition of “person” by the CAA at 42 USC §7602(e)), owners and operators of covered sites, manufacturers, vendors, and trade associations.

Commenter (0756-Baker Hughes) specifically supports the EPA proposal to retain 2020 Technical Rule amendments to the AMEL application requirements aimed at streamlining the process for evaluation and possible approval of advanced measurement technologies. The commenter notes that the amendments expand the pool of applicants for AMEL to include manufacturers and vendors, that allow applicants to supplement field data with modeling analyses, test data and other documentation, and that allow the application of approved AMEL to multiple sites will speed the development and deployment of innovative methane detection and control technology. The commenter adds that the speed and clarity of the AMEL process is critical to meeting the methane emission objectives shared by this Administration and the oil and gas industry.

Commenter (0820-Pioneer) supports the multiple reforms that EPA included to enhance the AMEL process to allow for emerging technologies in NSPS OOOOa. The commenter states they also support the application of approved emerging technologies by EPA to other sources within the oil and natural gas industry. Specifically, the commenter states that the EPA should allow for basin-wide equivalency determinations or basin-wide approvals, once equivalency has been demonstrated, and incorporation by reference of emerging technologies to other sites.

Commenter (0820-Pioneer) expresses additional support for the allowance for modeling and testing at a controlled test environment to demonstrate performance of a new technologies. They add that they also appreciate the EPA allowing for vendors and manufacturers as applicants for approval of emerging technology and not limiting the submissions to oil and natural gas companies with sites. The commenter explains that artificially limiting submissions to oil and natural gas companies prohibits the experts that are developing these new and emerging technologies from working with EPA and other stakeholders to implement the technologies as broadly as possible to reduce emissions at a lower cost.

Commenters (0820-Pioneer Natural Resources USA, Inc. (Pioneer), 0831-AXPC) support EPA’s recognition of approved state programs that are equivalent to EPA’s LDAR requirements and recommends that EPA continue with that allowance. It prevents redundancy of recordkeeping and reporting and allows for those state programs that are more stringent than EPA’s to continue. The commenters believe that state equivalency becomes even more important with EPA proposing emission guidelines that will require state plans. Without allowing for state equivalency, it will make developing and approving state plans more difficult in the future.

Response I-2-14: EPA acknowledges the various commenters support for the application of the AMEL provisions to work practices that apply to methane and VOC emissions. Many of the

points raised by commenters related to AMEL in the context of NSPS OOOOa and the associated AMEL process were discussed in the Response to Public Comments Document for the 2020 Technical Rule.<sup>37</sup> Since this rulemaking did not propose to alter that AMEL process for NSPS OOOOa, EPA directs commenters to that 2020 response to comment document and incorporates those comment responses here.

More specifically, in response to comments on the AMEL provisions in NSPS OOOOa related to permitting a broader application of AMEL technology alternatives, “point by point” equivalency, and basin-wide equivalency see EPA’s discussion in Sections V.C.1 and VI.C.1 of the preamble to the 2020 Technical Rule.<sup>38</sup> That discussion within those sections responds to all of these commenter’s suggestions regarding AMELs in the context of OOOOa.

Furthermore, in the context of NSPS OOOOb, EPA has taken a different approach that addresses many, if not all, aspects of these comments. While the AMEL provisions finalized in NSPS OOOOb are the same as in NSPS OOOOa, the final rule for OOOOb also includes separate provisions concerning alternative methane detection technologies. Please see section XI.A.1 of the November 2021 Proposal preamble for specific solicitations for comment regarding advanced measurement technologies. See also section IV.B (Advanced Methane Detection Technologies) of the December 2022 Supplemental Proposal on this topic, and section X.B (Advanced Methane Detection Technology Work Practices) of the final rule preamble. See also Volume II Chapter 5 (Advanced Methane Detection Technologies of the RTC for EPA’s responses to comments on alternative methane detection technology.

The comments summarized above regarding AMEL were provided prior to EPA having fully articulated an alternative methane detection and quantification program. EPA believes that many, if not all, concerns expressed by commenters above can be addressed via this new program that exists outside of the AMEL context. EPA believes the new alternative technology component of the rule should limit the number of AMEL applications and streamline alternative methane detection technologies that can be used under the rules. Once an alternative test method for an alternative technology has been approved, if it is broadly applicable, the EPA will post it to the Emission Measurement Center website.<sup>39</sup> Any owner or operator who meets the specific applicability for the alternative test method, as outlined in the alternative test method, may use the alternative test method to comply with the alternative periodic screening approach or alternative continuous monitoring approach.

Comment: Commenter (0938-TXOGA) notes that the EPA states that it is continuing approval of the Texas regulations that have been previously approved as alternatives for fugitive emissions components located at well sites and compressor stations in Texas. The commenter states that this will avoid the need for duplicative activities by companies.

Commenter (0755-TPA) also supports rule provisions that allow owners and operators of

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<sup>37</sup> Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration 40 CFR Part 60, subpart OOOOa Response to Public Comments on Proposed Rule [83 FR 52056, October 15, 2018] Comments. EPA-HQ-OAR-2017-0483-2291.

<sup>38</sup> 85 FR 57398 (September 15, 2020).

<sup>39</sup> <https://www.epa.gov/emc/oil-and-gas-approved-alternative-test-methods>.

compressor stations in Texas to comply with fugitive emissions standards promulgated by TCEQ in lieu of complying with equivalent standards in the federal NSPS, and the current proposal to extend those provisions to methane emissions for gathering and boosting stations as well as methane and VOC emissions for compressor stations in the transmission and storage industry segment. The commenter states that this increases flexibility for regulated companies, eliminates duplication at the state level, and eases compliance burdens, while still maintaining environmental protections.

Commenter (0820-Pioneer) supports EPA's recognition of approved state programs, specifically the Texas Standard Permit program, that are equivalent to EPA's leak detection and repair requirements and recommends that EPA continue with that allowance. The commenter states that it prevents redundancy of recordkeeping and reporting and allows for those state programs that are more stringent than the NSPS to continue.

Response I-2-15: EPA acknowledges the support of the specified alternative fugitive emissions standards that facilities may opt to utilize to demonstrate compliance with the fugitive emissions standards in §60.5397a. These alternative fugitive emissions standards have been finalized as proposed.

## **2.6 Pneumatic Pumps**

Comment: Commenter (0755-TPA) states that owners and operators of pneumatic pump facilities should have additional options to demonstrate no detectable methane emissions from CVS. The commenter notes that the EPA is proposing to amend current NSPS OOOOa requirements to allow pneumatic pump affected facilities to demonstrate no detectable methane emissions from CVS either by using annual Method 21 monitoring, as currently required, or by using one of two additional options: monthly audio, visual, olfactory (AVO) monitoring or OGI monitoring at the fugitive monitoring frequency. The commenter agrees that operators should have the ability to choose from all of these options with respect to demonstrations for methane emissions, just as they are currently allowed to choose from these options for VOC emissions demonstrations pursuant to amendments finalized in the 2020 Technical Rule.

The commenter (0755-TPA) suggests that the current proposal has the benefit of giving operators additional options beyond the use of Method 21. Method 21 is acceptable as an option but should never be required as the only acceptable monitoring method. In the experience of some of the commenters' members, Method 21 can be slow and cumbersome, while OGI can often be performed much more quickly and efficiently, as can AVO monitoring. Method 21 can also be relatively labor intensive and, as EPA itself has noted, "is not as cost-effective as OGI."<sup>40</sup> The proposal would also create efficiencies by allowing for the same monitoring method (OGI) to be used for pneumatic pumps located at the same site as controlled storage vessels. Moreover, as EPA points out, the commenter notes that OGI is already being used for sites that are subject to fugitive emissions monitoring and the CVS can readily be monitored during the fugitive emissions survey at little or no additional cost.<sup>41</sup> According to the commenter, providing an

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<sup>40</sup> See EPA-452/R-15-002, August 2015, "Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Gas Sector," at 7-29.

<sup>41</sup> See 86 FR 63 L62 (Nov. 15, 2021).

AVO option is a beneficial option, inter alia, because requiring either Method 21 or OGI for the sole purpose of monitoring CVS associated with a pneumatic pump would be unduly burdensome and would create substantial additional expense with little countervailing environmental benefit.

Response I-2-16: EPA acknowledges the support from the commenter and has finalized this provision as proposed.

## **2.7 Professional Engineer (PE) Certification**

Comment: Commenter (0755-TPA) states that in-house engineers should be allowed to make required certifications and determinations, as should non-PE outside personnel with appropriate expertise. The commenter notes that the EPA is proposing changes in NSPS OOOOa to the certification requirements regarding a determination that it is technically infeasible to route emissions from a pneumatic pump to a control device or process and regarding certification that design and operation of CVS will meet applicable requirements. The commenter adds that, specifically, the EPA is proposing to allow certification of technical infeasibility by either a PE or an in-house engineer with expertise on the design and operation of the pneumatic pump, and further to allow either a PE or an in-house engineer with expertise on the design and operation of the CVS to certify the design and operation will meet the requirement to route all vapors to the control device or back to the process.

The commenter (0755-TPA) supports the proposal to allow in-house engineers to make such certifications. The commenter adds that, as they have stated in prior comments, it is inappropriate to eliminate the ability of otherwise-qualified personnel to review and assess operations at regulated sources. The commenter explains that the fact is that in-house engineers are often the most experienced and knowledgeable personnel with respect to site design and control as well as specific design and feasibility questions, and as such they are often the most qualified personnel to make the assessments for which certifications are required.

Commenter (0755-TPA) also expresses that they believe that EPA should expand the universe of persons who could make required certifications and determinations to include non-PE outside personnel. According to the commenter, companies on occasion can experience shortages or temporary unavailability of personnel and in those instances rely on outside personnel. The commenter notes that such outside personnel can be as knowledgeable of and familiar with design and operations as in-house employees. They believe that company-hired contractors or consultants should also be allowed to sign off on certifications if they have appropriate expertise, *e.g.*, if they have designed the system in question. The commenter contends that this would provide additional flexibility without sacrificing any environmental protections because such third parties would have to have appropriate expertise on design and operation of the system in order to complete a certification or to make a required technical determination.

Similarly, commenter (0787-Atmos Energy Corporation (Atmos)) supports aligning NSPS OOOOa certification requirements for natural gas pneumatic pumps so that an in-house engineer can determine whether it is technically infeasible to route emissions from a natural gas



pneumatic pump to a control device or process. According to the commenter, in-house engineers are likely to have more knowledge about the site and can therefore apply a higher level of scrutiny to such determinations. Additionally, the commenter notes that in-house engineers have training comparable to PEs.

Commenter (0831-American Exploration and Production Council (AXPC)) supports EPA allowing for in-house engineers to be used for certification as the commenter agrees with EPA assessment that in-house engineers may be more knowledgeable about site design and control than a third-party PE.<sup>42</sup>

Commenter (0831-AXPC) adds that not only are in-house engineers likely to be more knowledgeable about site design but requiring PE certification can unnecessarily raise costs and delays, as there are not enough PEs certified in the required oil and natural gas requirements to support the rulemaking. Thus, if EPA wanted to require PE certification, it would need to provide significantly longer compliance timeframes to support the need to hire and train PEs.

Commenter (0585-Kentucky Oil and Gas Association (KOGA)) also supports EPA's proposal to maintain the change from the 2020 Technical Rule to permit a PE or an in-house engineer with experience in the design and operation of a CVS to perform certification. This will provide relief to the companies that have an engineering staff that is capable of performing this determination.

Response I-2-17: EPA acknowledges the support of the commenters regarding the allowance of certifications by either a PE or an in-house engineer with expertise related to the technical infeasibility to route pneumatic pumps to control and the certification of the design and operation of CVS that route vapors to control. The final rule allows certifications for these purposes by either a PE or an in-house engineer with expertise. EPA is not expanding this certification to include outside engineers that are not licensed PEs because the commenter did not provide information that demonstrates these outside engineers would have the same level of expertise required to make such evaluations for certification.

## **2.8 Natural Gas Processing Plant Initial Compliance Timeline for Leak Detection and Repair**

Comment: Commenter (0755-TPA) supports the extension of the 180-day initial compliance deadline regarding methane standards for leaks at processing plants. The commenter explains that, in rule amendments made in the 2020 Technical Rule, EPA clarified that the initial compliance deadline for VOC equipment leak standards at natural gas processing plants was 180 days. They state that this was a beneficial clarification for two reasons: first, it brought NSPS OOOOa in line with existing requirements in NSPS KKK, and second, it gave owners and operators a reasonable and workable period within which to bring affected equipment into proper operation and to conduct a thorough and accurate check on whether the equipment is in conformance with applicable leak standards.

Response I-2-18: EPA acknowledges the commenter's support for the proposed initial

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<sup>42</sup> 86 FR 63162 (Nov. 15, 2021).

compliance deadline for the leak detection and repair requirements at onshore natural gas processing plants. The final amendments to NSPS OOOOa include this initial compliance deadline as proposed.

## **Chapter 3. Significant Contribution Finding and the Congressional Review Act**

### **3.1 Regulation of Transmission and Storage Sources and Regulation of Methane**

#### ***3.1.1 Regulation of Transmission and Storage Sources***

Comment: Several commenters (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC), 0790-West Virginia Office of the Attorney General *et al.* (WV AG *et al.*), 0793-Permian Basin Petroleum Association (PBPA), 0921-U.S. Chamber of Commerce, 0819-State of West Virginia *et al.* (WV *et al.*)) assert that the November 2021 Proposal’s regulation of transmission and storage sources and regulation of methane violate Clean Air Act (CAA) section 111 because EPA has failed to make the threshold findings such regulation and, instead, reintroduced the 2016 NSPS OOOOa’s mistakes.

Commenter (0819-WV *et al.*) contends that the November 2021 Proposal reintroduced many of the 2016 rule’s mistakes. According to the commenter, the November 2021 Proposal once again tries to regulate the transportation and storage segments of oil and natural gas production sources without making the endangerment findings Congress required.

According to commenters (0790-WV AG *et al.*, 0819-WV *et al.*), to establish new source emission limits, EPA must list the category of stationary sources that “cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” CAA section 111(b)(1)(A). The commenters state that the EPA failed to make the requisite finding for transmission and storage sources. According to commenters, the agency neglects to acknowledge that it is creating a new source category for transmission and storage of oil and natural gas. This new category incorporates many types of stationary sources of oil and natural gas that were never included in the 1979 endangerment finding’s oil and natural gas production category—at least before the short-lived 2016 rule. Rather than make a SCF for this new category, EPA impermissibly relies on prior findings about different source categories emitting different pollutants. *Id.* at 63,134-35.

According to commenters (0790-WV AG *et al.*), the Proposed Rule tries to expand EPA’s authority to regulate sources of methane relating to oil and gas transmission and storage that EPA had never regulated before. But the Proposed Rule goes even further than the 2016 Rule. *Id.* at 63,116 (specifying that the Proposed Rule addresses “emissions sources previously not regulated under the 2016 NSPS”). Newly regulated sources include well liquid unloading operations and oil wells with associated natural-gas emissions. See *id.* at 63,117. EPA was wrong to add transmission and storage sources in 2016, and it appropriately reversed that decision in 2020. In the Proposed Rule, EPA misreads its own 1979 source category designation of oil and natural gas production sources to say that the category also reaches transportation and storage.

Commenters (0790-WV AG *et al.*) continue:

The circumstances surrounding EPA's 1979 rulemaking for production sources casts significant doubt on the Proposed Rule's reinterpretation of that category. EPA issued the 1979 Rule in response to Congress's directive to publish a list of "major stationary sources of air pollution." Priority List and Additions to the List of Categories of Stationary Sources, 44 Fed. Reg. 49,222 (Aug. 21, 1979). Congress knew that this rulemaking was a momentous change in environmental regulation. Thus, it required EPA not only to institute ordinary notice-and-comment proceedings when fashioning the rule, but also to consult "Governors and State air pollution control agencies" before issuing the list of new major sources categories. *Id.*

EPA did just that. The Agency collaborated with the Governors of all 50 States in a series of working group meetings and revised its initial proposal as a result of significant public input. 44 Fed. Reg. 49,222. The final list of major source categories came out of much deliberation and compromise, and accordingly, the source categories in the 1979 rule were worded carefully. For example, the initial set of major sources states that "petroleum transportation and marketing" could be a major source of pollution, but it did not reach the same conclusion for natural gas transportation. *Id.* at 49,226. Instead, the 1979 rule consciously decided to exclude both transportation sources, and found instead that "crude oil and natural gas production" met the statutory parameters. *Id.* (emphasis added).

The public debate that went into the 1979 rule makes it particularly difficult to reinterpret the major source categories EPA initially listed. After all, "regulatory drafting is often an exercise in political compromise," one that involves "the President, Congress, interest groups, and the courts." Jennifer Nou, *Regulatory Textualism*, 65 DUKE L. J. 81, 83 (2015). The parties involved carefully bargained over the meaning and scope of the 1979 rule, and it was the focus of intense public scrutiny. In reviewing the initial list of the major source categories, all parties studied the "provision-by-provision analyses in preambles" to interpret the public meaning of the regulation. *Id.* at 119. The "provision-by-provision" analysis for the 1979 rule reveals no intent to regulate natural gas storage or transportation, despite showing such intent for other categories like petroleum. 44 Fed. Reg. at 49,222. Under the rule, no then-regulated party, and no part of the group responsible for the drafting, would have believed that EPA had any authority to regulate oil and natural gas sources outside the production context.

The Proposed Rule's attempt to expand the 1979 rule is an impermissible shortcut around a regulatory compromise. The rule improperly shoehorns the transportation and storage segments into the existing category of oil and natural gas. Perhaps the Proposed Rule could make oil and natural gas transportation and storage a regulated source category—assuming EPA first makes a proper endangerment finding. But these areas are not currently within a listed category. Because of this conscious omission, EPA lacks authority to regulate here unless it does the legwork and finds that the transmission and storage segments of the industry contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare.

Commenter (0921-U.S. Chamber of Commerce) states that, gradually expanding the universe of sources within the transmission and storage segment as EPA proposes to do without making the requisite findings exacerbates the legal concerns they have with the rulemaking. The commenter contends that this approach could have the net effect of expanding an existing source category incrementally in an end run around the CAA's requirements to undertake an endangerment finding and a SCF. The commenter adds that, to the extent that additional emission sources are included in the supplemental proposal or any proposal thereafter within the oil and gas NSPS, EPA must comply with the process requirements of the statute for a source category expansion. The commenter concludes that the EPA should, therefore, take this opportunity to help ensure the legal durability of these important regulations by making all requisite findings for the transmission and storage segment.

Response I-3-1: The EPA disagrees with the adverse commenters' statements that the 1979 listing did not include the transmission and storage segment. The 2016 NSPS OOOOa stated that the Crude Oil and Natural Gas Production source category, as the EPA listed it for regulation under CAA section 111(b)(1)(A) in 1979, included the transmission and storage segment. The 2016 rule was correct – the EPA's 1979 listing of the source category should be considered to have included the transmission and storage segment. This is evident because the EPA's 1979 listing of the source category was part of a broader process in which the EPA comprehensively identified all of the nation's industrial source categories. The EPA did not specifically identify the transmission and storage segment as part of that process, and therefore it is logical that the EPA considered that segment to be part of the oil and gas source category.

In the 1977 CAA Amendments, Congress added CAA section 111(f)(1)-(2), which required the EPA to list additional source categories and promulgate standards of performance within certain periods of time, and established criteria for the EPA to determine priorities for promulgating those standards. 42 U.S.C. § 7411(f)(1)-(2) (1977). To implement these requirements, the EPA conducted a study that identified all the source categories it had not yet listed for regulation under CAA section 111(b)(1)(A) and that prioritized them for listing and regulation: *Priorities for New Source Performance Standards Under the Clean Air Act Amendments of 1977*, EPA-450/3-78-019 (April 1978) ("1978 Priority List"). Subsequently, the EPA revised the prioritization for some of the source categories, "Revised Prioritized List of Source Categories for New Source Performance Standards," EPA-450/3-79-023 ("1979 Priorities List"). The EPA then promulgated a final rule that, as required by CAA section 111(f), listed additional source categories for regulation under CAA section 111(b)(1)(A), consistent with the 1979 Priorities List. *See* 44 FR 49222 (Aug. 21, 1979) (1979 Listing Rule).

The 1978 Priorities List identified 203 source categories. This included 47 that it characterized as "minor" and therefore did not prioritize for regulation. Of the remaining 156, the report stated that a number could not be evaluated at that time due to lack of information, and therefore would not be prioritized for regulation. The report characterized the remaining source categories as "major," and prioritized them for regulation. *Id.* at 9. Thus, the report comprehensively identified all the nation's source categories. *Id.* at A-2, Table A-1 (listing "Source Categories Not Evaluated"); A-3 to A-6, Table A-2 (list of "Minor Sources"). The EPA confirmed the comprehensiveness of the 1978 Priorities List when it promulgated the 1979 Listing Rule. *See* 44

FR 49223 (noting that the 1978 Priorities List identified the source categories being listed for regulation, other source categories not evaluated, and minor source categories).

The 1978 Priorities List included, as one of the major source categories, “Crude Oil and Natural Gas Production Plants.” *See, e.g.*, 1978 Priorities List at 115, Table 3-12. The 1979 Priorities list included the same source category, 1979 Priorities List at 9, Table 3-2, and this source category was listed for regulation under CAA section 111(b)(1)(A) in the 1979 Listing Rule, under the name, Crude Oil and Natural Gas Production. 44 FR 49226. The EPA initially proposed NSPS for this source category in 1984. *See, e.g.*, 49 FR 2636, 2637 (Jan. 20, 1984). The EPA promulgated the initial NSPS for this source category in two 1985 rules. 50 FR 26122 (June 24, 1985) (VOC emissions from equipment leaks), 50 FR 40158 (Oct. 1, 1985) (SO<sub>2</sub> emissions). Both rules concerned onshore natural gas processing plants.

Although the 1979 listing identified the oil and gas industry as “Crude Oil and Natural Gas Production,” the above-described history of the 1979 listing and initial regulation of the oil and gas source category makes evident that from its inception the source category included the transmission and storage segment. The 1978 Priorities List, which, as noted above, was the report that formed the foundation for the EPA’s 1979 listing of the oil and gas source category, along with numerous other source categories, did not specifically identify the transmission and storage segment of the gas industry. However, the report was designed to comprehensively identify the nation’s industrial source categories. It included “major” source categories, which it indicated should be prioritized for regulation; “minor” source categories, which it indicated should not be prioritized for regulation; and ones that could not be evaluated because of a lack of information. 44 FR 49223. It is not plausible that this comprehensive listing would have overlooked the transmission and storage segment of the oil and gas industry, particularly when it included numerous “minor” source categories that did not merit regulation.

Commenters (0790-WV AG *et al.*) assert that the 1979 list was drafted by a team of stakeholders who negotiated its content, imply that the stakeholders negotiated over the scope of the oil and gas source category, and conclude that the result of that negotiation was that they gave the source category a narrow scope, as reflected in its title, “Crude Oil and Natural Gas Production.” Their assertion is not persuasive, for many reasons. That the 1979 listing would have been drafted by a team of stakeholders is not consonant with the EPA’s obligation to promulgate the listing through a notice-and-comment rulemaking process that must meet the requirements of CAA section 111 and withstand judicial review under CAA section 307(d)(9). Moreover, aside from the fact that CAA section 111(f) generally required EPA to consult with states before making listing decisions and promulgating standards, commenters do not cite any evidence of such negotiation in the record over the scope of any of the source categories and, in particular, they do not cite anything concerning the scope of the oil and gas source category. In any event, any consultation by the states would not have affected the fact that the background documents that formed the basis of the listing sought to comprehensively identify the source categories across the nation, as described above.

The initial regulation of the source category in 1985 concerned natural gas processing plants, which made clear that the scope of the source category was not limited to the production segment of the oil and gas industry, and instead was broader. This fact further undermines commenters

(0790-WV AG *et al.*) argument. They state, referring to their allegations that the 1979 listing was drafted by a negotiating team of stakeholders, “Under the rule, no then-regulated party, and no part of the group responsible for the drafting, would have believed that EPA had any authority to regulate oil and natural gas sources *outside the production context*” (emphasis added). However, in fact, the first standards promulgated for the source category were outside the production context – they were for the processing segment. Thus, it was clear from the outset that the source category was broader than just production sources.<sup>1</sup>

The EPA explicitly recognized that the source category included the transmission and storage segment in the 2012 NSPS OOOO, 77 FR 49496, when it first promulgated NSPS for sources in that segment; and again in the 2016 NSPS OOOOa, when it promulgated NSPS for additional sources in that segment.

In any event, the 2016 NSPS OOOOa further addressed the concerns commenters raised by re-listing the oil and gas source category to include the transmission and storage segment. That is, the 2016 rule went on to assume that the oil and gas source category as listed in 1979 did not include the transmission and storage segment, and then the rule revised the source category to include that segment and determined that the revised source category causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare, in accordance with CAA section 111(b)(1)(A).

The 2016 rule explained that it was appropriate to include the transmission and storage segment in the revised source category because that segment was interrelated with the production and processing segments. The 2016 rule’s basis for this determination is described in the preamble for this action.

The preamble also describes the major reasons why the transmission and storage segment is interrelated with the production and processing segments. In addition, across all the segments, the gas predominantly consists of methane. The natural gas enters the production and processing segments as field gas, and the processing changes its composition by removing most of the contaminants, those contaminants are a relatively small part of the gas. Moreover, some amounts of VOCs and HAPs remain in the gas; thus, the physical change in the composition of the gas simply means changes in the ratio of the methane, VOCs, and HAPs. For example, according to the 2020 Policy Rule, the average methane content of (i) produced gas ranges from 69-83%, (ii) gas in the processing segment is 78%; and (iii) gas in the transmission and storage segment ranges from 94-95%. 85 FR at 57029. This change in composition of the gas confirms that the segments are reasonably understood as comprising a sequence of functions leading to a single outcome, which is to convey methane, in as pure a form as possible, for distribution: the function of the production segment is to recover the gas, which is primarily methane, but with

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<sup>1</sup> The 2020 Policy Rule argued that in proposing the first standards of performance in 1984, 49 FR 2637 (1984), and promulgating them in 1985, 50 FR 26124 (June 23, 1985), the EPA’s description of the source category was limited to the production and processing segments. 85 FR 57025-26 (discussing the 1984 proposal). However, the 2016 NSPS OOOOa interpreted the 1984 proposal to be consistent with the scope of the source category including the transmission and storage segment, 81 FR 35832, but in any event, the 1985 rule’s standards were limited to the processing segment, and so the rule had no occasion to consider whether the source category extended to the transmission and storage segment. When the EPA turned to the transmission and storage segment in the 2012 rule, it recognized that the source category included that segment. 77 FR 49496.

contaminants; the purpose of the processing segment is to remove contaminants and thereby purify the methane; and the purpose of the transmission and storage segment is to convey the methane for distribution.<sup>2</sup>

Moreover, the same control requirements apply to all the segments. As described in the preamble, methods of monitoring for fugitive emissions using OGI to find leaks to prompt equipment repair or replacement and capturing emissions and routing to a control device such as a flare or routing to a process through a CVS and the requirements for process controllers, pumps, storage vessels, centrifugal and reciprocating compressors in production and processing are the same as for that same equipment in transmission and storage. The 2016 NSPS OOOOa pointed this similarity out as well. 2016 RTC at 1-16.

Further indication that the segments are interrelated is found in the effects that the segments have on each other. As the EPA stated in the 2016 NSPS OOOOa:

Because they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.*, feeding) them. For example, the relatively recent substantial increases in natural gas production brought about by hydraulic fracturing and horizontal drilling result in increases in the amount of natural gas needing to be processed and moved to market or stored. These increases in production and throughput can cause increases in emissions across the entire natural gas industry.

81 FR 35832. Similarly, regulatory requirements for the production and processing segments that reduce fugitive emissions or other forms of waste have the effect of increasing throughput for the transmission and storage segment.

While it is true that the production and processing segments use some different equipment than the transmission and storage segment, that is simply a result of the fact that the two sets of segments have different functions, and does not provide evidence that they are not interrelated. The production segment has some different equipment (such as equipment for a well completion) than the processing segment but those segments are well-recognized as interrelated. What is more relevant is that, as the EPA also explained in the 2016 NSPS OOOOa, “some equipment (*e.g.*, storage vessels, pumps, compressors) are used across the oil and natural gas industry, which further supports considering the industry as one source category.” 81 FR 35832. In fact, virtually all of the equipment used in the transmission and storage segment is also used in the production and processing segments. This includes methods of monitoring for fugitive emissions and storage vessels, pumps, process controllers, and compressors. While some equipment, such as dehydrators are used differently in the production and processing segments than in the transmission and storage segment, the key functions of the equipment, such as removal of water

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<sup>2</sup> It should also be noted that field gas produced in different basins in the U.S. varies widely in its amounts of VOCs and HAPs. Field gas produced in the Appalachian region has, on average, a higher percentage of methane (95.6%) and fewer contaminants than gas in the transmission and storage segment, on average, in the U.S. (94-95%, as noted above). See Memorandum to U.S. EPA from Eastern Research Group, “Natural Gas Composition,” Dkt. No. EPA-HQ-OAR-2017-0757 (November 13, 2018) (Table 2). The 2020 Policy Rule acknowledged that “[t]he composition of field gas varies across basins,” and notes that “the Appalachian region is predominantly dry gas and northern mid-continent (North Dakota) is primarily wet gas.” 84 FR 50248.



and impurities in the case for dehydrators and compressing fluids in the case of a compressor, remains the same regardless of segment.

In any event, the fact that there are differences among the sources in a source category does not indicate that the source category should be divided into smaller and more uniform source categories. In general, Congress recognized that a source category may include different sources, under CAA section 111(b)(2), which provides that “[t]he Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.” In the extreme case, if source categories were limited to sources that were identical, there would be no need for this authorization to subcategorize.

The scope of the source category as defined in 2016, and affirmed in this rule, is well within the reasonable bounds of the EPA’s past practice in defining source categories, which sometimes even contain sources that are located in multiple distinct industries. *See* 40 CFR part 60, subpart Db (industrial-commercial-institutional steam generating units), 40 CFR part 60, subpart IIII (stationary compression ignition internal combustion engines). In this regard, the House Report that accompanied the 2021 CRA joint resolution correctly noted that “even the presence of large distinctions in equipment type and emissions profile across two segments would not necessarily preclude EPA from regulating those segments as a single source category, so long as the EPA could identify some meaningful relationship between them,” House Report at 7, as the EPA did in the 2016 Rule. The EPA has included production, processing, transfer and storage sources in the same source category for the coal industry. Specifically, the coal preparation and processing plants source category includes thermal dryers, pneumatic coal-cleaning equipment, coal processing and conveying equipment (including breakers and crushers), coal storage systems, transfer and loading systems, and open storage piles. 40 CFR 60.250(d).

With respect to the Crude Oil and Natural Gas source category, the oil production segment differs from the natural gas production segment, and each of those segments differs from the natural gas processing segment, but those segments were placed in the source category in the 1979 listing. The natural gas transmission and storage segment does not differ more from the natural gas processing segment than oil production does.

That EPA has discretion in determining the scope of a source category, based, in some cases, on unique factors of the source category, is further illustrated by its treatment of petroleum refineries as a separate source category. The EPA appropriately identified petroleum refining as a separate source category in light of the enormous complexity of the petroleum industry. A refinery converts crude oil into a large number of different products and feedstocks for still more products, ranging from gasoline and fuel oils to asphalt and naphtha. It has extensive infrastructure for raw material intake and complex large-scale operations. Moreover, refineries tend to adapt their operations frequently to optimize production based on product specification (for example, type of gasoline) and market conditions. By contrast, produced natural gas is primarily intended to become a single product, sales gas, and requires much more simplified processing than petroleum does refining. The production, processing, transmission and storage segments provide a sequence of operations designed to produce this single product, and those operations seldom change. These differences between petroleum refining and the natural gas industry highlight the interrelatedness of the production, processing, transportation, and storage

functions for the natural gas industry. As the EPA stated in the 2016 NSPS OOOOa, “The process of producing natural gas for distribution involves operations in the various segments of the natural gas industry.... In contrast, oil production involves drilling/extracting oil, which is immediately followed by distribution offsite to be made into different products.” 81 FR 35832 n.26.

The EPA’s 1986 expansion of the source category of industrial fossil fuel-fired steam generators to include non-fossil fuel-fired steam generators as well as commercial and institutional steam generators, 51 FR 42794 (Nov. 25, 1986), provides a precedent for the EPA’s actions in the 2016 NSPS OOOOa. In 1979, the EPA added “Industrial Fossil Fuel-Fired Steam Generators: Industrial Boilers” to the list of source categories under CAA section 111(b)(1)(B). 44 FR 49222. After it began to develop new source performance standards for this source category, the EPA became aware of substantial similarities between the affected sources and other types of sources. 49 FR 25156 (June 19, 1984) (proposed expansion of the source category). Accordingly, in 1986, the EPA “amend[ed] the ... list for regulation under [CAA] section 111 ... by expanding the source category of industrial fossil fuel-fired steam generators to cover all steam generators, including both fossil and nonfossil fuel-fired steam generators, as well as steam generators used in industrial, commercial, and institutional applications.” 51 FR 42794. The EPA justified this expansion on the grounds that “[a]ll of these types of steam generators exhibit emission characteristics which are similar in quantity and type. Furthermore, the emission control devices which have been found to be effective on steam generating units are also effective in reducing emissions from other types of steam generators.” *Id.* at 42794-95. That is, “the emission control techniques which are applicable to fossil fuel-fired boilers are generally applicable to nonfossil fuel-fired boilers as well.” 49 FR 25156. The EPA went on to determine that this expanded source category of “industrial-commercial-institutional steam generating units contribute[s] significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.” 51 FR 42794.<sup>3</sup> Thus, in the 1986 steam generator rule, as in the 2016 NSPS OOOOa, the EPA revised the CAA section 111(b)(1)(A) list by expanding a source category to include more sources that had commonalities with the initially listed sources, including the same equipment, control technology, and types of emissions, and by making a new significant contribution and endangerment finding for the expanded source category.

The above discussion is sufficient to support the EPA’s view that in the 2016 NSPS OOOOa, the agency reasonably exercised its discretion to expand the source category to include the transmission and storage segment. While not essential to support that view, it should also be noted that some new sources in the transmission and storage segment have been subject to NSPS since the 2012 rule, and others since the 2016 rule. Numerous sources have complied with the NSPS, including making capital investments to install the requisite controls. See 2016 TSD. Commenters who argue that that the transmission and storage segment should be removed from the source category, and therefore that the NSPS for the affected sources should be rescinded, do not argue that the NSPS are unduly burdensome, and the EPA is aware of no evidence that the NSPS are unduly burdensome. The fact that the NSPS for the transmission and storage segment have been on the books and complied with by the affected sources, provides another reason to maintain them.

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<sup>3</sup> The EPA did not alter the treatment of utility steam generators as a separate source category. 51 FR 42794.

The legislative history of the joint resolution disapproving the 2020 Policy Rule makes clear that part of Congress' reason for that action was its intention that the EPA should include the transmission and storage segment as part of the oil and gas source category and promulgate GHG requirements for the sources in that segment.<sup>4</sup>

The objection of commenters (0921-U.S. Chamber of Commerce) to including the transmission and storage segment because, in its view, doing so incrementally expands the source category without making the requisite endangerment finding, is not valid. As noted, on the assumption that the source category as determined in the 1979 listing did not include the transmission and storage segment, in the 2016 NSPS OOOOa, the EPA revised the source category to include that segment and made an endangerment finding for the revised source category. Just as the EPA could have determined the source category to include the transmission and storage segment in 1979 (again, assuming that in 1979, the EPA did not determine the source category to include that segment), it could do so in the 2016 rule. The fact that it did not determine the source category to include the segment in 1979 (again, assuming that the EPA did not do so then) does not preclude it from revising the source category to include the segment later, as long as the EPA makes an endangerment finding for the revised source category. The EPA's discretion to determine the scope of a source category, subject to the constraints of CAA section 307(d)(9), extends to defining a source category to include the interrelated components of an industry. There is no basis under CAA section 111 to preclude the EPA from revising a source category to expand it simply because the EPA defined the source category more narrowly at an earlier point in time, as long as, again, the EPA makes an endangerment finding for the revised source category.

### ***3.1.2 Redundancy of Methane Regulation***

Comment: Commenter (0819-WV *et al.*) adds that the EPA also expands methane regulations through redundant and costly requirements.

In contrast, Commenter (0807-BP) notes that the regulation of methane emissions is not redundant with the regulation of VOC emissions because, among other reasons, regulation of methane established the predicate to regulate existing sources which emit the vast majority of methane.

Response I-3-2: The EPA responded in the preamble to the argument that under the 2016 NSPS OOOOa, the NSPS for GHG were redundant to the NSPS for VOC, and therefore unnecessary.

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<sup>4</sup> A commenter, -0921 (Chamber of Commerce), stated that pigging operations and related blowdown activities are not integrated with any of the segments. We explain in RTC vol. 1, chapter 18, that in the November 2021 Proposal, EPA solicited comment and data to assist the Agency in evaluating the potential for developing emissions standards for additional emission sources, including pigging operations and related blowdown activities. EPA did not propose emissions standards for pigging operations and related blowdown activities in the December 2022 Supplemental Proposal; therefore, this final action does not include emissions standards for these emission sources. We may consider regulation through a future action, including in the next 8-year review of the NSPS. Accordingly, it is not necessary to address this comment further at present.

## 3.2 Rational Basis Finding or Pollutant-Specific Significant Contribution Finding

### 3.2.1 General

Commenter (0763-TCEQ/RRC) questions EPA's authority to promulgate a NSPS for methane without first conducting a methane or greenhouse gas (GHG)-specific significant contribution finding (SCF) under CAA §111(b)(1)(A). The commenter stated that because the challenge to the 2020 Technical Rule remains pending, the petitions on the 2016 Rule continue to be stayed. As a result, the commenter asserts that the legal basis for the NSPS OOOO and NSPS OOOOa rules and EPA's interpretation of its authority under section 111 remain in question. The commenter adds that they believe a SCF is necessary prior to EPA regulating under CAA §111 and states that the EPA has not made a SCF here.

According to commenters (0790-WV AG *et al.*, 0819-WV *et al.*), to establish new source emission limits, EPA must list the category of stationary sources that "cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." CAA section 111(b)(1)(A). The commenters state that the EPA must make two separate findings: (1) that a given form of air pollution "may reasonably be anticipated to endanger the public health or welfare," and (2) that a given category of stationary sources "causes, or contributes significantly to" that air pollution. The commenters argue that the EPA refused to make either finding before issuing the November 2021 Proposal. Arguments include:

- From the outset, the agency has not even tried to make a timely endangerment finding. Instead, it impermissibly relies on prior endangerment findings, including its 2009 Finding that GHG emissions from automobile exhausts may, taken together, "reasonably be anticipated to endanger public health or welfare." 86 Fed. Reg. at 63,124. Beyond offering generalities about harms from methane emissions, EPA does not credibly attempt to make a similar finding for the specific pollutant at issue here. Unsurprisingly, EPA also fails to explain how emissions from mobile sources like cars can justify regulation at stationary facilities.

Commenter (0793-PBPA) states that, roughly a year before EPA's November 2021 Proposal, EPA acknowledged that two statutorily-mandated threshold questions must be answered before issuance of CAA section 111 standards. One of the questions involves the question related to making a methane-specific endangerment finding. As a predicate to promulgating new source performance standards, the commenter states that the EPA must determine that methane emissions from the oil and gas sector contribute significantly to endangerment. That is, determining a pollutant-specific endangerment finding for the source category requires EPA to determine that methane emissions from the oil and gas sector have a significant effect on global surface temperatures. After all, the commenter notes that Congress unambiguously applied the SCF requirement not only to the source category (here, the oil and gas sector), but also to the "air pollution" (here, methane) that actually causes the endangerment. According to the commenter, as EPA previously (and rightly) reasoned, "because Congress limited EPA to regulating only stationary sources in a category that the Administrator must first determine to cause or contribute

significantly to dangerous pollution, it is not reasonable to read ‘air pollutants’ to refer to any of the source category’s air pollutants for which EPA has not made a [SCF].”

Commenter (0763-TCEQ/RRC) questions EPA’s authority to promulgate a NSPS for methane without first conducting a methane or GHG-specific SCF under CAA section 111(b)(1)(A). The commenter asserts that a SCF is necessary prior to EPA regulating under CAA §111 and that EPA’s proposal has not yet made a SCF.

Commenters (0819- WV *et al.*, 0790-WV AG *et al.*) assert that the proposed rule cannot justify its failure to make pollutant- and source-specific finding by creating a new “rational basis” test. The commenters state that, in the November 2021 Proposal preamble, EPA claims authority to promulgate regulations for particular pollutants “as long as it has a rational basis for doing so.” 86 Fed. Reg. at 63,150. The commenters add that the agency explains that it need only satisfy the requirement to determine a source category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger the public health or welfare” when it first lists a category. Afterward, the commenters note that the EPA claims power to regulate any other pollutants “emitted from the source category” if it has “a rational basis to do so.” *Id.* The commenter contends that this interpretation cannot be squared with the plain text of the CAA. The commenters state that the EPA must make the SCF each time it regulates a pollutant from the source category. The commenters provide the following arguments:

...[t]he pollutant-specific reading flows naturally from the statutory text and structure. As a textual matter, the endangerment finding modifies and relates back to “air pollution,” not “sources.” 42 U.S.C §7411(b)(1)(A). The provision requires EPA to determine whether a source causes or contributes significantly to “air pollution which may reasonably be anticipated to endanger public health or welfare.” *Id.*... Only after the endangerment determination of a particular air pollutant may EPA look at whether the particular category of sources “contributes significantly” to that pollution. *Id.*

This text does not support EPA’s novel idea that a single endangerment finding at the source level can justify regulating any pollution the source may produce. Section 111(b)(1)(B) says EPA may issue performance standards after it lists a source category under Section 111(b)(1)(A). 42 U.S.C. §7411(b)(1)(B). Yet the definition of “standard of performance” is tied to the specific pollutants EPA concludes endanger health and welfare, not a generic cap on all potential pollutants the source might emit. *Id.* §7411(a)(1) (defining a “standard of performance” as “a standard for emissions of air pollutants”). Similarly, [s]ection 111(b)(3) commands the Administrator to “issue information on pollution control techniques for categories of new sources and air pollutants subject to the provisions of this section.” *Id.* §7411(b)(3) (emphasis added)

So the statute contemplates that the processes for adding new source categories and new air pollutants are the same: EPA must make the required findings to tie specific sources to specific pollutants. Yet EPA’s “rational-basis” approach creates inconsistency between how new source categories and new pollutants are added to the stationary source program. While new source categories must be added the traditional (and statutorily required) way, EPA can bootstrap jurisdiction over any new pollutants it chooses,

provided they come from existing source categories. The text does not support treating source categories and pollutants differently at all, let alone so dramatically.

Second, the CAA's text does not support EPA's rational-basis standard. The Proposed Rule cites no language from the statute saying the agency needs only a rational basis to regulate a new pollutant from an existing source category. Instead, the agency cites only a nonbinding House Report, a source that does not describe the actual legal standard nor have any power to change it. 86 Fed. Reg. at 63,150. This test is foreign to the CAA, and EPA's insistence on crafting a standard out of whole cloth is troubling.

Of course, it is easy to guess why EPA prefers the rational-basis standard. This low bar would allow EPA to bypass the endangerment finding altogether and ignore the reason Congress required it—confirming that a particular pollutant causes significant harm to health or welfare before greenlighting costly regulation. See *Coal. For Responsible Regul., Inc. v. EPA*, 684 F.3d 102, 117-18 (D.C. Cir. 2012) (per curiam), rev'd in part on other grounds sub. nom., *UARG*, 573 U.S. 302. The statute allows setting standards of performance only where the air pollutant “may reasonably be anticipated to endanger public health or welfare” and where emission of the pollutant from a particular source “causes, or contributes significantly” to that pollution. 42 U.S.C. § 7411(b)(1)(A).

These statutory terms matter. For one thing, they ensure that EPA cannot evade the requirement to consider costs when regulating new pollutants. The “upshot of inserting the adjective ‘significant’ was a consideration of which risks are worth the cost of elimination.” *Michigan v. EPA*, 213 F.3d 663, 677 (D.C. Cir. 2000) (per curiam). Congress also designed the pollutant-specific endangerment finding to make sure affected parties could hold EPA accountable for its decisions. By contrast, a rational-basis classification is almost impossible to challenge successfully in court. In the constitutional realm, for instance, a rational-basis classification will be upheld if there “is any reasonably conceivable state of facts that could provide a rational basis for the classification.” *FCC v. Beach Commc'ns, Inc.*, 508 U.S. 307, 313 (1993). Congress has deliberately chosen language that does not fit a standard where the actual costs of regulation are such weak backstops to new-claimed agency powers.

Perhaps EPA believes that there is room for a rational basis-approach because the statute is ambiguous. After all, the Supreme Court has held that “if the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute.” *Chevron, USA, Inc. v. Nat. Res. Def. Council, Inc.*, 467 U.S. 837, 843 (1984). But to find that ambiguity, an agency must use the “traditional tools of statutory construction.” *Epic Sys. Corp. v. Lewis*, 138 S. Ct. 1612, 1630 (2018) (quotation omitted). Nothing here suggests EPA has undertaken that effort. In fact, for the reasons explained, the traditional tools point toward an unambiguous, more rigorous standard—one that requires an endangerment finding for specific air pollutants before justifying nationwide regulation. Imagined ambiguity provides only superficial shelter.

Third, the rational-basis approach undermines the values of cooperative federalism embedded in the CAA. Congress intended the Act to address air pollution while also maintaining the traditional division of authority between federal and state regulators. When Congress delegated authority to EPA to enact clean air rules, it also emphasized that “air pollution prevention . . . is the primary responsibility of States and local governments.” 42 U.S.C. § 7401(a)(3). This respect for state sovereignty is reflected in other parts of the statute, too. Congress assigned the critical ability to develop implementation plans for existing sources to the States—plans “which, after EPA approval, are published as regulations in the Federal Register.” *People of State of Cal. ex rel. State Air Res. Bd. v. Dep’t of Navy*, 431 F. Supp. 1271, 1274 (N.D. Cal. 1977), *aff’d*, 624 F.2d 885 (9th Cir. 1980). The CAA repeatedly calls out the supremacy of States and local communities in controlling pollution. See, e.g., 42 U.S.C. § 7416 (“[N]othing in this chapter shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution.”); *id.* § 7431 (“[N]othing in this chapter constitutes an infringement on the existing authority of counties and cities to plan or control land use, and nothing in this chapter provides or transfers authority over such land use.”).

Grafting rational basis onto the statute defies these principles of federalism. Of course, the CAA imbues EPA with significant authority to set national performance standards, but it is not boundless. The demand to make and justify an endangerment finding for pollutants from a source category gives EPA meaningful guidelines—and preserves the States’ roles while keeping the agency within its own. In short, a rational-basis standard gives EPA a blank check that Congress never wrote.

Conversely, commenters (0458-Maryland Department of the Environment (MDE), 0807-BP America, Inc. (BP), 0926-Austin Energy (Austin) *et al.*) support EPA’s November 2021 Proposal to regulate methane in the oil and natural gas industry as a measure to meet its obligation under section 111(b) of the CAA.

Commenter (0926-Austin *et al.*) states that Congress’ disapproval of the 2020 Policy Rule under the CRA has reaffirmed EPA’s historical interpretation of CAA section 111 (which they support). The commenter adds that they agree that Congress has made clear that EPA does not have the authority to pursue actions that deregulate methane emissions from the source category or deregulate the transmission and storage segment. According to the commenter, in this case, it would be arbitrary and capricious for EPA to decline to regulate GHG emissions from the Crude Oil and Natural Gas source category given it is the largest source of anthropogenic methane emissions in the U.S., methane emissions are the second most significant GHG emissions in the U.S., and the impacts of greenhouse gas emissions from both new and existing sources. Thus, the commenter concludes that the EPA has a rational basis to regulate GHG emissions from the oil and natural gas source category.

Commenter (0807-BP) notes that the 2016 NSPS Rule established an appropriate basis for promulgating regulations to control methane emissions, in addition to volatile organic compound (VOC) emissions, from all of these segments. The commenter contends that, because EPA

previously determined the crude oil and natural gas source category causes or contributes significantly to air pollution, EPA is authorized to promulgate a NSPS for methane without requiring a new, pollutant-specific “endangerment” finding. Furthermore, the commenter states that the large amount of methane emissions from oil and gas sources and impact of methane emissions on climate change, plus the availability of cost-effective control options, provides EPA with a rational basis to regulate those emissions under CAA section 111.

Commenter (0844-Environmental Defense Fund *et al.* (EDF *et al.*)) asserts that there is no question that EPA is authorized to regulate GHG emissions under section 111 of the CAA. In *Massachusetts v. EPA*,<sup>5</sup> the Supreme Court held that the statute’s general definition of “air pollutant” appearing at 42 U.S.C § 7602(g) includes greenhouse gases, a finding it reaffirmed in *Utility Air Regulatory Group v. EPA* (UARG).<sup>6</sup> The commenter provides that the Court further ruled unanimously in *American Electric Power Company v. Connecticut* that section 111 of the CAA in particular “speaks directly” to GHG regulation, and that in enacting this provision, “Congress designated . . . EPA . . . as best suited to serve as primary regulator of greenhouse gas emissions.”<sup>7</sup>

In fact, in *Massachusetts*, the commenter (0844-EDF *et al.*) notes that the Court made clear that EPA must regulate sources’ GHG emissions—new motor vehicles, in that case—unless “it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do.”<sup>8</sup> Following the Court’s instructions, in 2009, the commenter states that the EPA concluded that emissions of six well-mixed GHG emissions from mobile sources—including methane—do, indeed, “cause or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare.”<sup>9</sup> The commenter contends that the Endangerment Finding was made after an extraordinarily thorough scientific review and careful consideration of public comments. It was reaffirmed after full consideration of petitions for reconsideration and was upheld in its entirety by the D.C. Circuit in the face of a vigorous industry challenge.<sup>10</sup> The commenter added that the Court found that the Endangerment Finding was procedurally sound, consistent with Supreme Court case law, and amply supported by the administrative record, observing that “[t]he body of scientific evidence marshaled by EPA in support of the Endangerment Finding is substantial.”<sup>11</sup> And while it granted certiorari on one component of the D.C. Circuit’s holding in *CRR I*, the Supreme Court declined to review any aspect of the lower court’s holding on the Endangerment Finding.<sup>12</sup>

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<sup>5</sup> 549 U.S. 497, 529 (2007).

<sup>6</sup> 573 U.S. 302, 316 (2014).

<sup>7</sup> 564 U.S. 410, 424, 428 (2011).

<sup>8</sup> *Massachusetts*, 549 U.S. at 533.

<sup>9</sup> Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) (“the Endangerment Finding”).

<sup>10</sup> *Coal. for Responsible Regulation, Inc. v. EPA* (*CRR I*), 684 F.3d 102, 116-27 (D.C. Cir. 2012), *aff’d in part, rev’d in part sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014) and amended sub nom. *Coal. for Responsible Regulation, Inc. v. EPA* (*CRR II*), 606 F. App’x 6 (D.C. Cir. 2015).

<sup>11</sup> *Id.* at 120.

<sup>12</sup> See *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 418, 2013 U.S. LEXIS 7380 (Oct. 15, 2013).



The commenter (0844-EDF *et al.*) contends that the 2009 Finding fully satisfies any requirement for an endangerment determination under CAA section 111, not only for the NSPS OOOOa rule and the NSPS OOOOb and EG OOOOc proposals, but for any other listed source category for which EPA may set GHG standards going forward. The commenter states that the EPA made very clear in 2009 that the endangerment component of its finding rule applied generally to the sum total of all anthropogenic GHG “air pollution,” irrespective of the sources from which the individual “air pollutants” were emitted.<sup>13</sup> This distinction originates in the CAA itself. Section 202(a)(1) provides that

[t]he Administrator shall by regulation prescribe (and from time to time revise) in accordance with the provisions of this section, standards applicable to the emission of any *air pollutant* from any class or classes of new motor vehicles or new motor vehicle engines, which in [her] judgment cause, or contribute to, *air pollution* which may reasonably be anticipated to endanger public health or welfare.<sup>14</sup>

Thus, the commenter (0844-EDF *et al.*) concludes that the statutory provision applied in the 2009 Endangerment Finding required EPA to consider whether “air pollution” may reasonably be anticipated to endanger, not the “pollutant” itself.

Furthermore, the commenter (0844-EDF *et al.*) adds that the scientific research conducted in the 12 years since the Endangerment Finding was issued has not merely reaffirmed the Finding’s fundamental conclusion but has made clear that climate change is much more dire—and that deep and immediate cuts to anthropogenic GHG emissions are much more urgently needed—than was understood even a decade ago. The commenter provides that the research conducted after EPA issued the NSPS OOOOa rule in 2016 demonstrates that methane emissions, in particular from the oil and gas sector, are not only enormous, but are markedly higher than previous estimates (including EPA’s) suggested. According to the commenter, while EPA need only articulate a rational basis for issuing methane regulations from this source category under CAA section 111, it would be justified in issuing such regulations even if it *were* required (which it is not) to formally determine that an individual pollutant emitted by a source category significantly contributes to dangerous pollution.<sup>15</sup> The commenter concludes that there can thus be no legitimate dispute that, consistent with *Massachusetts*, *UARG*, and *American Electric Power*, EPA not only *may* regulate oil and gas methane emissions under section 111, but *must* do so.

Furthermore, the commenter (0844-EDF *et al.*) asserts that the EPA correctly determined in the NSPS OOOOa rulemaking that the quantity of methane emitted by the oil and gas source category easily qualifies as “significant” under any reasonable definition. The commenter reports that, although the agency asserted in NSPS OOOOa that it need not make such a pollutant-specific significant finding in order to issue CAA section 111 standards, and the House Report

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<sup>13</sup>See, e.g., 74 Fed. Reg. 66,496, 66,506 (Dec. 15, 2009) (“[T]he Administrator is to consider the cumulative impact of sources of a pollutant in assessing the risks from air pollution, and is not to look only at the risks attributable to a single source or class of sources.”).

<sup>14</sup> 42 U.S.C. § 7521(a)(1) (emphasis added).

<sup>15</sup> For more discussion of this question, see Part III.D.2 of the commenter’s letter (NSPS OOOOa’s “Significance” Finding for Oil and Gas Methane Emissions Is Neither Flawed Nor Required To Justify the Rule’s Methane Standards.”).

accompanying the 2021 CRA resolution affirmed that position, the record leaves no doubt that oil and gas sector methane emissions are “significant” in any event. Thus, the commenter states that under any feasible interpretation of CAA section 111, EPA may thus issue GHG regulations for the oil and gas sector in the form of methane standards.

Commenter (0914-Class of ’85 Regulatory Response Group (Class of ’85)) states that, for decades, EPA has interpreted section 111(b)(1) of the CAA as requiring an SCF only for the initial listing of the source category and then authorizing the Agency to regulate any pollutant emitted by that source category—provided that EPA has a rational basis for doing so. However, the commenter notes that the EPA reinterpreted CAA section 111(b)(1) in its 2020 Policy Rule, finding that the statute “requires the Administrator to make—or, at least, authorizes the Administrator to require—a pollutant-specific SCF” each time EPA proposes to regulate a pollutant emitted by a listed source category.<sup>16</sup> In its comments on the proposed 2020 Policy Rule, the commenter states that they urged EPA to refrain from adopting the new interpretation of CAA section 111(b)(1) because it would interfere with the regulatory certainty and consistency on which electric generators and other regulated industries depend when making business decisions. The commenter reaffirms those comments here in support of EPA’s November 2021 Proposal to reaffirm the longstanding interpretation of CAA section 111(b)(1). The commenter provides that CAA section 111(b)(1) does not compel EPA to make a pollutant-specific SCF.

Commenter (0914-Class of ’85) notes that, while the statute sets out criteria for listing source categories (*i.e.*, whether a source category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare”), it does not expressly establish criteria for the regulation of specific pollutants. CAA section 111(b)(1)(B) instructs EPA to promulgate standards of performance and revise them as the Administrator deems appropriate, signaling that the decision of which pollutants should be regulated under CAA section 111(b) is left to the discretion of the Agency. In exercising this discretion, the commenter states that the EPA must demonstrate that it has a rational basis for setting standards for listed source categories (*i.e.*, that the Agency is not acting arbitrarily or capriciously in promulgating such regulations).<sup>17</sup> The commenter states that, as the Agency explained in its response to comments on the 2016 NSPS for the oil and natural gas sector—which preceded the 2020 Policy Rule—“the EPA’s use of the phrase ‘rational basis’ . . . explains how the agency’s actions are supported by the record and is a reasonable exercise of the EPA’s broad authority

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<sup>16</sup> See, e.g., 80 Fed. Reg. 64,510 (Oct. 23, 2015) (NSPS for fossil fuel-fired EGUs); 77 Fed. Reg. 9304 (Feb. 16, 2012) (NSPS for fossil-fuel-fired electric utility, industrial-commercial-institutional, and small industrial-commercial institutional steam generating units); 75 Fed. Reg. 54,970 (Sept. 9, 2010) (NSPS for Portland cement plants); 74 Fed. Reg. 51,950 (Oct. 8, 2009) (NSPS for coal preparation and processing plants); 73 Fed. Reg. 35,838 (June 24, 2008) (NSPS for petroleum refineries); 70 Fed. Reg. 28,606 (May 18, 2005) (NSPS for coal-fired electric utility steam generating units); 54 Fed. Reg. 34,008 (Aug. 17, 1989) (NSPS for fluid catalytic cracking unit regenerators); 52 Fed. Reg. 47,826 (Dec. 16, 1987) (NSPS for industrial-commercial-institutional steam generating units); 50 Fed. Reg. 36,956 (Sept. 10, 1985) (NSPS for Portland cement plants); 41 Fed. Reg. 3826 (Jan. 26, 1976) (NSPS for primary aluminum reduction plants).

<sup>17</sup> The commenter states that, when the CAA does not provide specific criteria for EPA’s actions under a particular provision, as under section 111(b)(1)(B), the Agency is held to the “arbitrary or capricious” standard under Section 307(d)(9) of the Clean Air Act, 42 U.S.C. § 7607(d)(9) (providing that a court may reverse an EPA action that is “arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law”), and section 706(2) of the Administrative Procedure Act, 5 U.S.C. § 706(2) (same).

under section 111.” The commenter adds that, except for the nine-and-a-half months during which EPA required a pollutant-specific SCF, throughout the life of the NSPS program EPA has reasonably interpreted CAA section 111(b)(1) to require an SCF as a prerequisite only for the initial listing of a source category. The commenter concludes that the EPA should not revert to the short-lived requirement to establish a pollutant-specific SCF.

Response I-3-3: The EPA disagrees with the commenters who assert that CAA section 111 requires, or authorizes the EPA to require, a pollutant-specific SCF as a predicate to regulation of air pollutants under CAA section 111. We agree with the commenters who say that CAA section 111 imposes a rational basis test as the predicate. We explain our interpretation of CAA section 111 and respond to the main adverse comments in the preamble.

In addition, we note the following:

Interpreting these provisions of CAA section 111 to entail a rational basis standard for standards of performance is consistent with the purpose of CAA section 111, which Congress explained when it adopted the section in the 1970 CAA Amendments.

According to the report of the Senate Committee on Public Works: “The provisions for new source performance standards are designed to ensure that new stationary sources are designed, built, equipped, operated, and maintained so as to reduce emissions to minimum. ... The overriding purpose of this section would be to prevent new air pollution problems....” S. Rep. 91-1196 at 15-16 (Sept. 17, 1970). The report explained that to achieve this purpose, the standards would (i) apply to “[m]ajor new facilities such as electric generating plants ... petroleum refineries ... and various other commercial and industrial operations;” and (ii) be based on “application of the latest available emission control technology or through other means of preventing or controlling air pollution.” *Id.*

This purpose is reflected in the requirements of CAA section 111 that the EPA identify categories of stationary sources that contribute significantly to dangerous air pollution, and then, on a specified timetable, promulgate standards, based on the “best system of emission reduction ... adequately demonstrated,” for emissions of the air pollutants.

This purpose can be achieved by applying a standard of rationality to the EPA’s promulgation of standards for the air pollutants emitted from the source category, consistent with CAA section 307(d)(9)(A). There is no need for an additional requirement that the EPA also determine that an individual air pollutant contributes significantly to dangerous air pollution, as a predicate to promulgating a standard for that air pollutant. In fact, such a requirement would undermine the purposes of CAA section 111. To see this, assume that the EPA lists a source category under CAA section 111 because it emits numerous air pollutants that, taken together, contribute significantly to dangerous air pollution. Consistent with the “overriding purpose of [CAA section 111] ... to prevent new air pollution problems,” S. Rep. 91-1196 at 15-16 (Sept. 17, 1970), the EPA must address each air pollutant that could lead to a “new air pollution problem[]” by promulgating standards of performance that “reduce emissions to a minimum.” These standards should apply to all of the air pollutants that the source category emits, except for any emitted in minor amounts or any that do not have adverse impacts on health or welfare. Interposing an

additional limitation, that the EPA may promulgate standards only for particular air pollutants that it determines contribute significantly to dangerous air pollution, may prevent the EPA from addressing some of the source category's emissions, in this example, and thus may undermine the purpose of CAA section 111.

The commenters asserting that CAA section 111 requires, or authorized the EPA to require, a pollutant-specific SCF, do not offer an interpretation of CAA section 111 that supports their assertions. They point to the reference in CAA section 111(a)(1) to “air pollutants” as part of the definition of “standard of performance” and the requirement in CAA section 111(b)(3) that the EPA issue information on pollution control techniques for “air pollutants,” but those provisions are consistent with the CAA section 111 requirements that the EPA promulgate standards for emissions of air pollutants and offer no support for the commenters' assertions that a pollutant-specific SCF is necessary as a predicate for such standards. More specifically, CAA section 111(b)(1)(B) requires the EPA, once it has listed a source category, to promulgate “standards of performance,” and CAA section 111(a)(1) defines a “standard of performance” as a “standard for emissions of air pollutants” that must be based on systems of emission reduction for those pollutants. The requirement in CAA section 111(b)(3) for the EPA to issue information on pollution control techniques is consistent with those requirements because such information could inform those standards. But the reference in CAA section 111(a)(1) and (b)(3) to “air pollutants” does not somehow point towards a requirement for a significant contribution finding determination for a particular air pollutant as a predicate for promulgating the standards. Most importantly, as discussed in the preamble, CAA section 111(b)(1)(A), by its terms, requires the EPA to determine the effect of a “category of sources” on “air pollution,” and contains no such requirement for “air pollutants.”

The 2020 Policy rule offered an interpretation of CAA section 111 to support its view that the provision requires, or at least authorizes the EPA to require, a pollutant-specific significant contribution finding as a predicate to promulgating an NSPS for a new pollutant, but commenters did not endorse this interpretation and the EPA considers it strained and rejects it.<sup>18</sup> The 2020 rule stated that the source categories that the EPA is required to list under CAA section 111(b)(1)(A) typically emit multiple air pollutants, and that although CAA section 111(b)(1)(B), read together with CAA section 111(a)(1), requires that the EPA promulgate standards for “emissions of air pollutants,” it does not specify which air pollutants. The 2020 rule drew a comparison to the provisions for the new source review prevention of significant deterioration (PSD) program under CAA section 165(a)(1) and 169(1), as interpreted by the Supreme Court in *Utility Air Regulatory Group v. EPA*, 573 U.S. 302 (2014) (*UARG*).<sup>19</sup> Those provisions apply the PSD requirements to stationary sources that emit specified amounts of “any air pollutant.” The Court held that the phrase “any air pollutant” in CAA section 169(1) does not include GHG, even though they are air pollutants. The Court explained that the statutory context made clear

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<sup>18</sup> Note that the 2019 proposal for the 2020 Policy rule offered a somewhat different legal interpretation than in the 2020 rule. Because the 2020 rule did not finalize that proposed interpretation, we do not think it merits further discussion here. 84 Fed. Reg. 50260.

<sup>19</sup> In *UARG*, the Court interpreted the similar provisions of the Title V permit program, CAA sections 501(2)(B) and 302(j), the same way. 573 U.S. at 323-24.

that the PSD program could not reasonably be applied to sources on account of their GHG emissions.

This is because the program’s applicability limits, which are based on specified tons of pollutants emitted, and its substantive and procedural requirements, which the Court found created “heavy ... burdens,” were intended by Congress to apply to “a relative handful of large sources.” However, according to the Court, because GHG are emitted in much higher quantities than other air pollutants, applying the PSD requirements to sources on account of their GHG emissions would create anomalous results by expanding the program to large numbers of small sources that were not equipped to carry those burdens. 573 U.S. at 322-23.

The 2020 Policy Rule sought to apply the reasoning of *UARG* to argue that CAA section 111(b)(1)(B)’s requirement that the EPA promulgate standards for “emissions of air pollutants” should not apply to all air pollutants, but only those for which the EPA made a pollutant-specific significant contribution finding. The 2020 Policy Rule reasoned that this limitation is necessary to avoid “the risk that the EPA may regulate air pollutants emitted in small quantities or otherwise having little adverse effect.” 85 FR 57037.

The 2020 Policy Rule’s on *UARG* is misplaced. In *UARG*, the Court’s holding that the term “any air pollutant” in CAA section 169(1) does not include GHG, and therefore that the PSD program does not cover sources on account of their GHG emissions, was informed by other of the CAA provisions for the PSD program, including applicability limits and substantive and procedural requirements, that the Court found would create anomalous results if the PSD program applied to those sources. CAA section 111 includes no comparable provisions. That is, there are no other provisions in CAA section 111 that would create anomalous results unless the EPA is limited to promulgating standards for “emissions of air pollutants” only for air pollutants that the EPA makes a significant contribution finding for. On the contrary, the 2020 Policy Rule’s concern that limits are necessary to ensure that the EPA does not attempt to promulgate standards for air pollutants emitted in minor amounts or that are innocuous can be addressed through the rational basis test. In fact, as discussed above, other relevant provisions support the rational basis test; in particular, CAA section 307(d)(9)(A) applies the arbitrary or capricious standard for judicial review, which is consistent with the rational basis test.

Other CAA provisions that do explicitly require a pollutant-specific finding – for the most part, a cause-or-contribute finding – highlight that CAA section 111 does not do so. When Congress adopted CAA section 111(b)(1)(A)-(B) and 111(a)(1) in the 1970 CAA Amendments, and revised them in the 1977 CAA Amendments, Congress also adopted or revised several other provisions that by their terms required the EPA to make a pollutant-specific finding, although Congress used somewhat different phrasing in some of those provisions. These provisions include CAA sections 108, 112, 115, 202, 211, and 231.<sup>20</sup> The inclusion of clear requirements

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<sup>20</sup> See CAA section 108(a)(1)(A)-(B), 42 U.S.C. 1857c-3(a)(1)(A)-(B) (1970) (Administrator is required to publish a list “which includes each air pollutant which in his judgment has an adverse effect on public health or welfare” and “the presence of which in the ambient air results from numerous or diverse mobile or stationary sources”); CAA section 112 (added in 1970 CAA Amendments and revised in 1977 CAA Amendments; “hazardous air pollutant” is defined as, in relevant part, “an air pollutant . . . which in the judgment of the Administrator causes, or contributes

for pollutant-specific findings in other CAA provisions confirms that the absence of such a requirement in section 111 indicates Congress' intention not to include such a requirement there. *See United States v. Gonzales*, 520 U.S. 1, 5 (1997) ("Where Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (internal quotations omitted).<sup>21</sup>

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to, air pollution which may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness;" this definition was substantially revised in the 1990 CAA Amendments); CAA section 115(a), 42 U.S.C. 1857d(a) (1970) (Administrator is authorized to take action to address "pollution of the air in any State or States which endangers the health or welfare of any persons"); CAA section 202(a)(1), 42 U.S.C. 1857f-1(a)(1) (1970) (Administrator is required to regulate "the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in his judgment causes or contributes to, or is likely to cause or to contribute to, air pollution which endangers the public health or welfare"); CAA section 202(a)(1), as revised by the 1977 CAA Amendments, 42 U.S.C. 7521(a)(1) (1977), ("The Administrator shall by regulation prescribe . . . standards applicable to the emission of any air pollutant from any class or classes of new motor vehicles or new motor vehicle engines, which in his judgment cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare"); CAA section 211(c)(1), 42 U.S.C. 1857f-6(c)(1) (1970) (Administrator is authorized to regulate "any fuel or fuel additive for use in a motor vehicle or motor vehicle engine if any emission products of such fuel or fuel additive will endanger the public health or welfare"); CAA section 211(c)(1)(A) (as revised in 1977 CAA Amendments; the Administrator is authorized to regulate any fuel or fuel additive "if in the judgment of the Administrator any emission product of such fuel or fuel additive causes, or contributes, to air pollution which may reasonably be anticipated to endanger the public health or welfare"); CAA section 231(a)(2), 42 U.S.C. 1857f-9(a)(2) (1970) (Administrator is required to regulate "emissions of any air pollutant from any class or classes of aircraft or aircraft engines which in his judgment cause or contribute to or are likely to cause or contribute to air pollution which endangers the public health or welfare"). In addition, in the 1990 CAA Amendments, Congress adopted several additional provisions that require findings that bear some similarity to the findings discussed above. These include (1) CAA section 129(e) (Administrator or state is required to require the owner or operator of any unit to comply with emission limitations or implement any other measures, if the Administrator or the state determines that emissions in the absence of such limitations or measures may reasonably be anticipated to endanger public health or the environment"); (2) CAA section 183(f)(1)(A) (Administrator is required to promulgate standards for VOC and any other air pollutant from loading and unloading of tank vessels "which the Administrator finds causes, or contributes to, air pollution that may be reasonably anticipated to endanger public health or welfare"); (3) CAA section 213(a)(1)–(3) (Administrator is required to (i) conduct a study to determine if emissions from nonroad engines and nonroad vehicles "cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare;" (ii) determine whether emissions of certain pollutants from new and existing nonroad engines and vehicles "are significant contributors to ozone or carbon monoxide concentrations in more than 1 area which has failed to attain the national ambient air quality standards (NAAQS) for ozone or carbon monoxide;" and if so, (iii) promulgate regulations containing standards applicable to such emissions from those classes or categories of new nonroad engines and new nonroad vehicles "which in the Administrator's judgment cause, or contribute to, such air pollution") (CAA section 213(a)(4), which concerns different pollutants than under CAA section 213(a)(2)–(3), has requirements similar to the requirements of those provisions); (4) CAA section 615 (Administrator is required to regulate "[i]f, in the Administrator's judgment, any substance, practice, process, or activity may reasonably be anticipated to affect the stratosphere, especially ozone in the stratosphere, and such effect may reasonably be anticipated to endanger public health or welfare").

<sup>21</sup> The 2019 proposal for the 2020 Policy rule stated that although Congress included a significant contribution finding for the source category, and not for individual pollutants, it may have conflated the two, and the proposal pointed to these other provisions to support that view. 84 FR 50264. The 2020 rule did not pursue this argument, and the EPA rejects it. CAA section 111(b)(1)(A)–(B) and 111(a)(1) are clear by their terms in requiring a source category finding and not a pollutant-specific one, in contrast to several other CAA provisions; the proper interpretation is that Congress meant what it said in CAA section 111, and that is highlighted by the contrast with

A closer look at the provisions adopted or revised in the 1970 and 1977 CAA Amendments shows differences between them and CAA section 111, which further highlight that CAA section 111 does not include a requirement for a pollutant-specific finding. As discussed above, in CAA section 111, Congress directed the EPA to identify the source category for regulation, including making a significant contribution and endangerment finding for it, and then promulgate standards for the air pollutants emitted from it on the basis of technological or other systems of emission reduction. In contrast, in several of the other 1970 or 1977 provisions, Congress identified the source category for the EPA to regulate, and then directed the EPA to regulate air pollutants from it that cause or contribute to dangerous air pollution. *See* CAA section 202(a) (classes of new motor vehicles or new motor vehicle engines); section 231(a)(2) (classes of aircraft or aircraft engines).<sup>22</sup> In several other provisions, Congress directed the EPA to regulate air pollutants that the EPA determines cause or contribute to dangerous air pollution, without reference to source categories. *See* CAA sections 108(a)(1)(A)-(B) (pollutants that adversely affect public health or welfare and result from numerous or diverse sources), 112 (hazardous air pollutants), 115(a) (pollutants that originate in the U.S. and cross into, and endanger public health or welfare in, a foreign country).<sup>23</sup> In other provisions, Congress directed the EPA to regulate products if emissions from them cause or contribute to dangerous air pollution. *See* CAA 211(c)(1) (fuels).

In all of these provisions, Congress directed the EPA to identify air pollutants that contribute to an air pollution problem, as a predicate for regulation. In contrast, under CAA section 111, Congress directed the EPA to identify source categories that significantly contribute to dangerous air pollution, as a predicate for regulation, and then to control air pollutants from the listed source categories through application of control technology or other system of emission reduction, without any requirement to further identify particular air pollutants.

In the preamble, the EPA explains that the rational basis test is consistent with the EPA's lengthy regulatory history under CAA section. On the other hand, in several previous rules, the EPA rejected comments that it was required to make a pollutant-specific significant contribution finding. In the 2009 rule for the coal preparation and processing plant source category, the EPA rejected comments that it was required to make pollutant-specific significant contribution findings for the pollutants it was regulating for the first time from that source category as a predicate for regulation. 74 FR 51957. In the 2015 rule for electric utility generating plants, the EPA rejected similar comments for GHG, and explained that the sole predicate was that the EPA have a rational basis for regulating GHG. 80 Fed. Reg. 64510, 64530 (Oct. 23, 2015).<sup>24</sup>

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what Congress said in the other CAA provisions, not that Congress meant something it did not say in CAA section 111. Furthermore, CAA section 213(a)(4) explicitly requires the EPA to make two findings -- (1) emissions from new nonroad engines or vehicles contribute significantly to an air pollution problem, and (2) emissions from classes or categories of new nonroad engines or vehicles cause or contribute to the air pollution problem -- which indicates that Congress knows how to provide such a two-finding requirement and chose not to do so in CAA section 111.

<sup>22</sup> Provisions added in the 1990 CAA Amendments follow a similar pattern. *See* CAA section 129(e) (solid waste incineration units), 183(f)(1)(A) (loading and unloading of tank vessels), 213(a) (nonroad engines).

<sup>23</sup> A provision added in the 1990 CAA Amendments follows a similar pattern. *See* CAA section 615 (regulation of any substance, practice, process, or activity that affects the stratosphere and endangers public health or welfare).

<sup>24</sup> In the technical support documents for several of the first section 111(d) emission guidelines for existing sources

In addition, interpreting CAA section 111 to require a pollutant-specific SCF is inconsistent with CAA section 111(f). Congress added CAA section 111(f) in the 1977 CAA Amendments, and revised it in the 1990 CAA Amendments, for the purpose of requiring the EPA to promulgate CAA section 111 standards on a faster pace. The 1977 CAA Amendments adopted CAA section 111(f)(1), which required the EPA to list under CAA section 111(b)(1)(A), within one year, major stationary source categories not already listed, and to promulgate standards of performance for them within three to five years. 42 U.S.C. § 7411(f)(1) (1977). The 1977 CAA Amendments also adopted CAA Section 111(f)(2), which included criteria for the EPA to determine priorities for promulgating those standards. 42 U.S.C. § 7411(f)(2) (1977). By 1990, the EPA still had not made what Congress considered to be satisfactory progress in promulgating standards of performance for the listed source categories. Accordingly, the 1990 CAA Amendments revised CAA section 111(f)(1) to update the schedule for the EPA to promulgate the remaining standards.

As noted above, by the time of the 1977 and 1990 CAA Amendments, the EPA had promulgated numerous rulemakings under CAA section 111, and had never interpreted the provision to require a pollutant-specific significant contribution finding. The Courts have held that Congress is considered to be aware of an administrative interpretation under certain circumstances. *See Lorillard v. Pons*, 434 U.S. 575, 580 (1978) (“Congress is presumed to be aware of an administrative or judicial interpretation of a statute and to adopt that interpretation when it re-enacts a statute without change”).

In the 1977 and 1990 CAA Amendments, Congress left in place the essential requirements of CAA section 111(b)(1)(A) that the EPA list source categories that contribute significantly to dangerous air pollution, of CAA section 111(b)(1)(B) that the EPA conduct rulemaking to promulgate standards of performance, and of CAA section 111(a)(1) defining standards of

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that the EPA promulgated, the EPA included statements that CAA section 111 required the EPA to determine that the pollutant subject to regulation contributed significantly to dangerous air pollution. 84 FR 50266 (citing the emission guidelines that accompanied the technical support documents); *see, e.g.*, EPA, “Final Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants,” EPA-450/2-77-005, at 2-1 (Mar. 1977)) (“Before [section 111(b)] standards may be established, the Administrator must find that the pollutant in question ‘may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare’ [see section 111(b)(1)(A)]. Because this finding is, in effect, a prerequisite to the same pollutant being identified as a designated pollutant under section 111(d), all designated pollutants will have been found to have potential adverse effects on public health, public welfare, or both.”) Contrary to assertions in the 2019 proposal, 84 FR 50266, these statements do not indicate that the EPA previously interpreted CAA section 111 to require a pollutant-specific significant contribution finding as a predicate for promulgated standards of performance for any air pollutant. The statements are in the background section of technical support documents for emission guidelines under CAA section 111(d), and are intended to make clear that the EPA has established the necessary predicate for regulating emissions from existing sources. Any such pollutant-specific significant contribution finding itself is not relevant for emission guidelines. If EPA had taken the position that such pollutant-specific significant contribution findings were necessary, it would have made them in either the rulemakings that listed the source categories or the rulemakings that promulgated standards of performance for new sources. In fact, the EPA did not make any such findings in those actions. For example, in the rulemaking that promulgated standards of performance for fluoride emissions from phosphate fertilizer plants, the EPA correctly noted that it had listed the source category by determining that “these categories of sources contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare....” 39 FR 37603 (Oc. 22, 1974). Those statements in the emission guidelines technical support documents should be viewed as erroneous, overly simplified summaries of the CAA section 111 rulemaking process intended only to provide background information.



performance as standards for emissions of air pollutants determined in a specified manner.<sup>25</sup> In addition, Congress added and then amended requirements in CAA section 111(f) to accelerate that rulemaking to promulgate standards of performance. Under these circumstances, Congress should be presumed (i) to have been aware that the EPA interpreted CAA section 111(b)(1)(B) to apply a standard of rationality in determining which pollutants to regulate, and not to require, or authorize the EPA to require, a pollutant-specific significant contribution finding; and (ii) to have adopted that interpretation.

Moreover, nothing in CAA section 111(f) or its legislative history indicates that Congress intended the EPA to promulgate a pollutant-specific significant contribution finding. CAA section 111(f)(2)(A)-(B) requires the EPA to consider “the quantity of air pollutant emissions” from each source category and “the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare” in prioritizing rulemaking. Those provisions, by their terms bear some similarity to the terms that Congress has used in other CAA provisions that require pollutant-specific cause-or-contribute findings, noted above, and thus highlight that Congress knew how to require pollutant-specific contribution findings, and did not do so in CAA section 111.

On the contrary, interpreting CAA section 111 to require a pollutant-specific SCF would unavoidably slow down EPA promulgation of standards of performance and could lead to fewer standards, which is inconsistent with Congress’ intention in adopting CAA section 111(f) to require the EPA to adopt standard for quickly. *See* House Committee on Interstate and Foreign Commerce, *Clean Air Act Amendments of 1977*, at 194–195, 95th Cong. (May 12, 1977) (H. Rept. 95–294).<sup>26</sup>

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<sup>25</sup> Congress amended some of the provisions of CAA section 111(b)(1)(A) in the 1977 CAA Amendments, and amended some of the provisions of CAA section 111(a)(1) in both the 1977 and 1990 CAA Amendments, *compare* 42 U.S.C. 7411(a)(1) (1970) *with* 42 U.S.C. 7411(a)(1) (1977) *and* 42 U.S.C. 7411(a)(1) (1990), but those amendments did not change the essential requirements noted above.

<sup>26</sup> In the 1977 CAA Amendments, Congress amended the terms of six CAA provisions, CAA sections 111(b)(1)(A), 108, 112, 202, 211, and 231, that each established cause-or-contribute, significant contribution, endangerment or similar findings, to make their provisions more uniform and more preventive or precautionary in nature. The House-Senate Conference Report described the amendments to these six provisions, as a group, with the following statement: “In all future rulemaking in these areas, the Administrator could regulate any air pollutant from those sources, the emissions of which ‘in his judgment cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare.’” H.R. Rep. No. 95–564, at 183–84 (1977). Contrary to statements in the 2019 proposed rule, 84 FR 50264–65, this statement in the Conference Report cannot be read to support interpreting CAA section 111 as requiring a pollutant-specific significant contribution finding. This statement was a paraphrase of all the six provisions, taken together. Most of them – all but CAA section 111 – do require by their terms, a pollutant-specific cause-or-contribute or similar finding, and so the statement reflects that approach. But none of the six provisions uses the precise wording set off by quotation marks in the statement: “in his judgment cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare.” That the statement is designed to be a general paraphrase is clear by the fact that it is not accurate with respect to CAA section 108. That provision does not authorize the EPA to regulate emissions directly, rather, it authorizes the EPA to list pollutants, which sets in motion a process that results in the states regulating air pollutants. In any event, even if the statement could be read to interpret CAA section 111 to require a pollutant-specific finding – and it should not be read in that way, but if it is – that finding would be only a cause-or-contribute finding, and not a significant contribution finding. Similarly, the Report of the House Committee on Interstate and Foreign Commerce also

The 2020 Policy Rule asserted that rational basis test is vague, so that under it, the EPA could promulgate standards of performance for sources that emit minimal quantities of air pollutants, or air pollutants with no adverse effects on public health or welfare. The EPA disagrees with this view. As noted above, what the EPA has termed the rational basis test is fully consistent with the arbitrary or capricious standard of review under CAA section 307(d)(9)(A), and that standard of review is well established. In the seminal case of *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42-43 (1983), the Supreme Court explained that under this standard of review, “the agency must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made,” and the court will uphold the rule if it is “rational, based on consideration of the relevant factors and within the scope of the authority delegated to the agency by the statute.” In making rational basis determinations under CAA section 111, the EPA has considered the amount of the air pollutant emitted by the source category, both in absolute terms and by drawing comparisons, as well as the availability of control technologies. See *National Lime Assoc. v. EPA*, 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (discussing the EPA’s reasons for not promulgating standards for NO<sub>x</sub>, SO<sub>2</sub> and CO from lime plants); 80 FR 64510, 64530 (October 23, 2015) (rational basis determination for GHGs from fossil fuel-fired electricity generating power plants); 73 FR 35838, 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries). Courts routinely review rules under the “arbitrary and capricious” standard, as noted in the House Report, at 11.

Beyond general assertions that the rational basis test is vague, the 2020 rule did not identify any instances in the more than 50 years of EPA rulemaking under CAA section 111 in which its use led, or could have led, to the poor outcomes they postulate – *i.e.*, EPA regulation of air pollutants that have no adverse impacts due to their small quantities or innocuous effects. On the contrary, as noted in the preamble, in a 1980 rulemaking to promulgate standards of performance for lime manufacturing sources, the EPA declined to regulate NO<sub>x</sub> emissions on grounds that the source category emitted only small amounts of that pollutant. This regulatory history is consistent with the incentives that drive EPA action, which are to devote its limited resources to complying with its statutory obligations and promulgating regulation that improves public health and welfare. In any event, if the EPA did promulgate standards of performance for air pollutants emitted in minimal amounts or innocuous air pollutants, the Courts could invalidate them as arbitrary or capricious under CAA section 307(d)(9)(A).

In any event, it is clear that the 2020 rule’s concerns have no validity in this rulemaking--the methane emissions from the Crude Oil Natural Gas source category cannot be considered few in quantity or innocuous in their effects. As discussed in the preamble, this source category is by far

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included a statement summarizing the amendments to the various provisions, which was that the amendments “provide the same standard of proof for regulation of any air pollutant.” H.R. Rep. No. 94-1175, at 33 (1976). The 2019 proposal cited this statement as well to support its interpretation that CAA section 111 requires or authorizes the EPA to require a pollutant-specific significant contribution finding. 84 Fed. Reg. at 50,265. Like the above-discussed statement from the Conference Report, the one from the House Committee was a general summary designed to apply to all the amended provisions, most of which concerned pollutant-specific findings, and cannot be read as an indication of congressional intent that CAA section 111 require a pollutant-specific finding. In any event, and again as with the Conference Report statement, if the House Committee statement is interpreted to support a pollutant-specific finding – and it should not be so interpreted, but if it is – that finding would be only a cause-or-contribute finding, and not a significant contribution finding.

the largest emitter of methane emissions in the U.S., and methane emissions are responsible for a large portion of the climate impacts of GHG.

The EPA also agrees with the comments by industry stakeholders (0914-Class of '85 Regulatory Response Group (Class of '85)) that revising the EPA's long-standing interpretation of CAA section 111 to require an SCF only for the initial listing of the source category and then to authorize the Agency to regulate any pollutant emitted by that source category—provided that EPA has a rational basis for doing so – with a requirement, or authorization for the EPA to require a pollutant-specific SCF each time the EPA proposes to regulate a pollutant emitted by a listed source category, would interfere with the regulatory certainty and consistency on which electric generators and other regulated industries depend when making business decisions.

In addition, we also note that, as explained in the preamble, the 2016 NSPS OOOOa made, in the alternative, a pollutant-specific SCF for GHG from the Crude Oil and Natural Gas source category, as well as an endangerment finding for GHG air pollution, which addresses the concerns of adverse commenters on this rule.

### ***3.2.2 Methane-specific Endangerment Finding, including Significant Contribution Finding***

Comment: Commenter (0793-PBPA) states that as a predicate to promulgating new source performance standards, the EPA must determine that methane emissions from the oil and gas sector contribute significantly to endangerment. That is, determining a pollutant-specific endangerment finding for the source category requires EPA to determine that methane emissions from the oil and gas sector have a significant effect on global surface temperatures. After all, the commenter notes that Congress unambiguously applied the SCF requirement not only to the source category (here, the oil and gas sector), but also to the “air pollution” (here, methane) that actually causes the endangerment.

In contrast, Commenter (0844-EDF *et al.*) states that, although the Endangerment Finding technically addresses a pollutant it defines as “the mix of six long-lived and directly-emitted greenhouse gases”—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluorides<sup>27</sup>—EPA is well within its authority to regulate methane in particular as the designated pollutant. In *American Electric Power*, the commenter provides that the Supreme Court left no doubt that EPA may, under CAA section 111, regulate specific GHGs (carbon dioxide, in that case) among the six well-mixed pollutants that were the subject of the 2009 Endangerment Finding.<sup>28</sup>

Response I-3-4: The EPA disagrees with the comment stating that a methane-specific significant contribution is required. If CAA section 111 requires the EPA to make a pollutant-specific endangerment finding, it is appropriate for that finding to be for GHG, not methane, for the reasons explained in the preamble.

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<sup>27</sup> See 74 Fed. Reg. at 66,497.

<sup>28</sup> See generally *Am. Elec. Power Co.*, 564 U.S. at 401.

### ***3.2.3 Whether to Base Endangerment Findings on A Predetermined Threshold***

Comment: Commenter (0793-PBPA) states that, another question is related to meeting articulated criteria for judging significance of contribution. The commenter suggests that the EPA articulate criteria for distinguishing between a “contribution” and a “significant contribution” to dangerous pollution and, before regulating under CAA section 111, must conclude that the pollutant and source category being assessed meet the test for the latter. The commenter contends that the EPA has sensibly pronounced that without articulated criteria, “it is impossible to evaluate whether [a SCF] is well reasoned.” In the absence of articulated criteria, the commenter states that any prior or present-day determination of significant contribution or “rational basis” EPA may claim is arbitrary.

Commenter (0914-Class of '85) notes that the EPA proposes to reaffirm that when the Agency makes an endangerment finding for a source category under section 111(b)(1)(A) of the CAA, “that finding should be made in consideration of the particular facts and circumstances, not a predetermined threshold.” The commenter supports the Agency’s November 2021 Proposal to maintain the long-accepted interpretation and practice for how the Administrator makes an endangerment finding. Specifically, the commenter supports EPA’s November 2021 Proposal to reaffirm that endangerment findings be made “in consideration of the particular facts and circumstances” and to reject the establishment of a predetermined threshold for what constitutes a “significant contribution” to air pollution under section 111(b)(1)(A). The commenter asserts that the concept of a predetermined SCF threshold was a departure from the longstanding approach EPA has taken in determining significant contribution and endangerment on a case-by-case basis.<sup>29</sup> As the Agency explains in the November 2021 Proposal, “[d]uring the 50 years that it has made listing decisions, the EPA has always relied on the individual facts and circumstances.” The commenter states that industrial sectors and local air agencies have come to rely on EPA’s established interpretation of CAA section 111(b)(1)(A). The commenter concludes that the EPA should continue to evaluate significant contribution and endangerment on a case-by-case basis, which will allow the Agency to consider the wide range of information available about source categories and their emissions. The commenter states that this will ensure that regulated entities are treated fairly based on all of the particular facts and circumstances that may be relevant to EPA’s listing of new source categories under CAA section 111.

Response I-3-5: The EPA disagrees with the comment stating that a significant contribution must be made on the basis of an established standard or criteria. Any significant contribution finding required under CAA section 111 may be made on the basis of the facts and circumstances, for the reasons explained in the preamble.

### ***3.2.4 Other Aspects of Endangerment Finding***

Comment: Commenter (0793-PBPA) states that, although Congress disapproved the 2020 Policy Rule under the Congressional Review Act (CRA), EPA is still obliged to follow the express

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<sup>29</sup> See *Coal. for Responsible Regulation*, 684 F.3d at 122–23 (the inquiry “necessarily entails a case-by-case, sliding-scale approach to endangerment because ‘[d]anger . . . is not set by a fixed probability of harm, but rather is composed of reciprocal elements of risk and harm, or probability and severity.’ EPA need not establish a minimum threshold of risk or harm before determining whether an air pollutant endangers.”) (internal citation omitted).

terms of the statute. In articulating its methane-specific endangerment finding and the significant contribution criteria, the commenter suggests that the EPA:

- (1) compare methane emissions from the U.S. oil and gas industry[11] to worldwide methane emissions in order to adjudge whether the former significantly contributes to global climate change; and
- (2) demonstrate how the proposal will not lead to an increase in global methane emissions if declines in domestic oil and gas production due to these standards is counteracted by increased production in countries with relatively less stringent emission control requirements.

Response I-3-6: In the 2016 NSPS OOOOa, the EPA made an alternative significant contribution finding for GHG from the Crude Oil and Natural Gas source category, in part on the basis of comparing the methane emissions from that source category to world-wide methane emissions. *See* 81 FR 35839-40 and Tables 6-7 (“As illustrated by the domestic and global GHG comparison data summarized above, the collective GHG emissions from the oil and natural gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 32 percent of United States methane and 3.4 percent of total United States emissions of all GHG), global (where this sector, while accounting for 0.5 percent of all global GHG emissions, emits more than the total national emissions of over 150 countries, and combined emissions of over 50 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination.”).

The EPA disagrees with commenters’ assertion that the EPA should demonstrate how the proposal will not lead to an increase in global methane emissions if declines in domestic oil and gas production due to these standards is counteracted by increased production in countries with relatively less stringent emission control requirements. That assertion is irrelevant to the question of whether emissions from the U.S. oil and gas source category contribute significantly to dangerous air pollution. *See Massachusetts v. EPA*, 549 U.S. 497, 533-34 (2007) (assertions that regulating GHG might impair President’s ability to negotiate with foreign nations to reduce emissions are irrelevant to the question of whether GHG from U.S. motor vehicles contribute to climate change). In any event, that assertion is also speculative with respect to the impact of standards of performance on U.S. production, the impact of U.S. production changes on foreign production, and the emission controls on foreign production.

### **3.3 2020 Policy Rule**

Comment: Commenter (0793-PBPA) states that, although Congress disapproved the 2020 Policy Rule under the CRA, EPA is still obliged to follow the express terms of the statute and, at the very least, should better explain its disregard of threshold questions as part of this process. The commenter provides that the EPA’s proposal “broaden[s] the types of sources” subject to regulation and requires, “for the first time[,] regulation of hundreds of thousands of existing sources across the country.” And EPA projects that the rule as proposed would result in an annual domestic oil production decline of 12.2 million barrels, which will inevitably cause another country—undoubtedly with relatively less stringent emission control requirements—to

seize the opportunity to increase production (and methane emissions) accordingly.<sup>30</sup> The commenter contends that, while EPA has a role to play with respect to regulating methane emissions, the commenter contends that, under these circumstances it is incumbent on EPA to comply with unambiguous statutory predicates and its prior, well-reasoned interpretations of them.

Response I-3-7: In explaining the rationale for this action in the preamble and in responding to comments in the preamble and this response-to-comments document, the EPA has explained why it rejects the statutory interpretations in the 2020 Policy Rule.

### **3.4. Oil and Gas Methane CRA Joint Resolution**

Comment: Commenter (0808-American Petroleum Institute (API)) argues that the CRA rescission of the 2020 Policy Rule does not extend to the legal rationale and policy positions used to justify the 2020 Policy Rule and does not endorse the legal and policy interpretations in the preceding 2012 and 2016 rules.

Commenter (0808-American Petroleum Institute (API)) adds that “EPA’s suggested approach would indiscriminately and inappropriately sweep away legal and policy positions stated in the record of the Policy Rule that are necessary for proper implementation of CAA § 111. For example, EPA explains in the preamble to the final Policy Rule that VOC ‘are not the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d).’ 85 Fed. Reg. at 57040. Reversal of this uncontroversial interpretation would cause CAA § 111(d) to have a far broader scope than is reasonable or warranted under the plain text of the statute. Such an outcome is not required or supported by the CRA action.”

Commenter (0808-API) states that the CRA applies to “rules.” The commenter notes that when EPA promulgates a final rule, the “rule” is the regulatory text (which imposes legal obligations or creates legal rights) and not the explanation and justification provided in the preamble to the rule. Thus, according to the commenter, a rescission under CRA section 801(b)(1) and the prohibition under CRA section 801(b)(2) on issuing a rule in substantially the same form apply only to the relevant regulatory text and do not apply to EPA’s explanation in the administrative record that accompanies the regulatory text. Contrary to EPA’s suggestion, the commenter asserts that the legislative history of this particular CRA action cannot and does not change the plain meaning of the CRA statute. See *INS v. Cardoza-Fonseca*, 480 U.S. 421, 452-3 (1987) (J. Scalia, concurring in the judgment) (“Judges interpret laws rather than reconstruct legislators’ intentions. Where the language of those laws is clear, we are not free to replace it with an unenacted legislative intent.”).

Similarly, commenter (0819-WV *et al.*) contends that the CRA resolution has no legal effect beyond undoing the 2020 Policy Rule. The commenter states that it does not authorize the 2016 Rule’s deviations from CAA section 111’s limits on EPA’s authority. The commenter adds that the resolutions of disapproval passed under the CRA cannot expand an agency’s statutory

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<sup>30</sup> As just one example, if the proposed rule is finalized PBPA projects a 9% increase in global methane emissions were Turkmenistan to incrementally replace our lost domestic oil production.

powers. The CRA provides only that a rule disapproved by joint resolution “shall not take effect or continue,” and that “a new rule that is substantially the same as such a rule may not be issued, unless the reissued or new rule is specifically authorized” by subsequent congressional act. 5 U.S.C. §801(b). In other words, the commenter states that the limits that empowering statutes place on agencies do not change after Congress enacts a CRA resolution. The commenter notes that resolutions can only further restrict agency power—they preclude regulatory actions “substantially similar” to actions taken under the disapproved rule. *Id.* According to the commenter, the CRA’s silence about the statute underlying the disapproved rule does not implicitly repeal existing statutory constraints. Indeed, “repeals by implication are not favored” and will not be “infer[red] . . . unless such a construction is absolutely necessary . . . in order that the words of the later statute shall have any meaning at all.” *Nat’l Ass’n of Home Builders v. Defs. of Wildlife*, 551 U.S. 644, 662 (2007) (quotations and alterations omitted). The commenter states that no such inference is needed here. The CRA’s meaning is plain without resorting to reading it to repeal separate limits on agency authority.

As to the 2021 CRA resolution specifically, the commenter (0819-WV *et al.*) notes that the November 2021 Proposal claims that “[i]n disapproving the 2020 Policy Rule under the CRA, Congress explicitly rejected the 2020 Policy Rule interpretations and embraced EPA’s rationales for the 2016 . . . [R]ule.” 86 Fed. Reg. at 63,147-48. The commenter states that the EPA relies for support on legislative history and statements of individual members of Congress who supported the Resolution, see *id.* at 63,149, rather than grounding its conclusion in the CRA Resolution’s purportedly “express” text.

According to the commenter (0819-WV *et al.*) a CRA resolution, like any act of Congress, operates through its enacted language. “[O]nly the words on the page constitute the law adopted by Congress and approved by the President.” *ACA Connects - Am.’s Comme’ns Assn. v. Frey*, 471 F. Supp. 3d 318, 325 (D. Me. 2020) (quoting *Bostock v. Clayton Cnty.*, 140 S. Ct. 1731, 1738 (2020)). CRA resolutions are not interpreted by reference to “[c]ongressional debates and public statements,” but by “the ordinary public meaning of its terms at the time of its enactment.” *Id.* Faced with a CRA resolution like this one, the commenter states that the court in *ACA Connects* concluded that the resolution “nullifi[ed]” the prior rule, but “create[d] no overarching federal policy, and enact[ed] no scheme” directing future regulation. *Id.*

Commenter (0819-WV *et al.*) contends that because the 2021 CRA resolution contains no language that so much as hints at CAA section 111’s limits—much less amends them—it cannot support the November 2021 Proposal’s attempts to bypass them. The commenter adds that while it is true, EPA may not choose a new rule substantially similar to the rule Congress disapproved, but the rule it does choose must satisfy CAA section 111.

Commenter (0790-WV AG *et al.*) states that, by nullifying the 2020 Policy Rule, the CRA resolution effectively re-imposed the 2016 Rule. But it did not enact that rule’s reading of the CAA into law. Many of the November 2021 Proposal’s statutory failings are outgrowths of those that underscored the 2016 Rule. The November 2021 Proposal does not shy away from this overlap but embraces it—and casts the CRA resolution as legal support for its reading. This interpretation puts more weight on the resolution than it can bear. According to the commenter,

the CRA resolution has no legal effect beyond undoing the 2020 Policy Rule. It does not authorize the 2016 Rule's deviations from CAA section 111's limits on EPA's authority.

Response I-3-8: The EPA responds to these comments in the preamble. In addition, commenters cite *ACA Connects - Am. 's Commc 'ns Assn. v. Frey*, 471 F. Supp. 3d 318 (D. Me. 2020) (*ACA Connects*) to support their argument that the legislative history of the joint resolution is not relevant, but that case is distinguishable and does not provide support. In that case, plaintiffs, which were trade associations whose members included internet service providers (ISPs) in the state of Maine, sought declaratory and injunctive relief against a Maine state statute that protected the privacy of online customer information (the Maine statute). As relevant here, the plaintiffs/ISPs argued that the Maine statute was preempted on grounds that it was in conflict with a CRA joint resolution that Congress had adopted.<sup>31</sup> That joint resolution had disapproved a 2016 Federal Communications Commission (FCC) internet service provider (ISP) privacy order (the FCC Order), which, in turn, had repealed earlier FCC action.<sup>32</sup>

The plaintiffs/ISPs argued that the legislative history of that joint resolution included statements from Congressmen that they sought to prevent the imposition of rules that affected only ISPs, and further sought to facilitate the creation of a single, uniform set of privacy rules. The plaintiffs/ISPs asserted that those statements amounted to a federal scheme that the Maine statute conflicted with, and therefore that the Maine statute was preempted.

The District Court rejected this argument. It noted that the one sentence joint resolution stated that “Congress disapproves the [FCC Order]... [which] shall have no force or effect.” *Id.* at 325 (quoting the joint resolution). The court went on to state that “only the words on the page constitute the law adopted by Congress and approved by the President,” and that those “words on the page” were simply the text of the joint resolution, not the congressional debates. *Id.* (quoting *Bostock v. Clayton Cty., Georgia*, 140 S.Ct. 1731, 1738 (2020) (emphasis omitted)). Accordingly, the District Court concluded that Congress's disapproval of the FCC Order “creates no overarching federal policy, and enacts no scheme with which the Maine ... [s]tatute can conflict.” *Id.*

Contrary to the commenters, the EPA considers the legislative history of the CRA joint resolution disapproving the 2020 Policy rule to be important because it clarifies Congress's purposes for disapproving the rule and its intentions for how the EPA should respond. We do not read *ACA Connects* to call our view into question. As discussed above, when Congress enacted the CRA, it stipulated that the legislative language of a joint resolution would be a one-sentence disapproval of the agency action, and its sponsors recognized the importance of using the legislative history to express congressional intention for how the agency could or should proceed with further rulemaking.

Congress followed this approach in disapproving the 2020 Policy Rule. The language of the joint resolution was a one-sentence disapproval, in accord with the requirements of the CRA, and both the Senate sponsors and the House Committee explained the flaws in the 2020 rule and their

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<sup>31</sup> S.J. Res. 34, Pub. L. No. 115-22, 131 Stat 88 (Apr. 3, 2017).

<sup>32</sup> “Protecting the Privacy of Customers of Broadband and Other Telecommunications Services,” 81 FR 87274 (December 2, 2016).



intention for further EPA action. In *ACA Connects*, the plaintiffs/ISPs argued that the legislative history of the joint resolution disapproving the FCC Order constituted a federal scheme of a single, uniform set of privacy rules, with respect to which the Maine statute was in actual conflict. But that argument was clearly incorrect. The legislative history could not, and did not purport to, create federal requirements in-and-of-itself. On the contrary, some of the statements in the legislative history -- consistent with the purposes of the CRA as expressed by its sponsors, noted above -- recommended further action that the FCC could take. *See* 163 Cong. Rec. H2497 (2017) (statement of Rep. Capuano) (stating that the FCC should take case-by-case action instead of comprehensive regulation); *id.* at S1928 (Sen. Thune) (same). Therefore, the legislative history of the joint resolution disapproving the FCC Order was irrelevant for the purposes asserted by plaintiffs/ISPs, as the District Court held, but that has no bearing on the importance of the legislative history of the joint resolution disapproving the 2020 Policy Rule for the present rulemaking.

Comment: Conversely, commenter (0844-EDF *et al.*) states that, as a result of the CRA resolution, the 2020 Policy Rule was “made of no force or effect” and must “be treated as though [it] had never taken effect.” The commenter adds that, moreover, EPA is now prohibited from issuing “a new rule that is substantially the same as” the 2020 Policy Rule unless Congress passes new legislation permitting it. The commenter contends that any attempt by EPA either to remove the transmission and storage sector from the oil and gas source category as regulated under CAA section 111 or to rescind methane standards for this source category would directly violate a congressional dictate and would be “arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law.”<sup>33</sup> The commenter adds that, even if Congress had not enacted (and the President had not signed) the CRA resolution, EPA would still have been compelled to reverse the 2020 Policy Rule and reinstate the NSPS OOOOa rule’s standards and source category definition. According to the commenter, this is because the 2020 Policy Rule was based on patently incorrect legal foundations and was plainly arbitrary and capricious, as the commenters stated they explained in detail in their comments submitted to EPA on the 2020 Policy Rule.<sup>34</sup> The commenter provides a brief summary of reasons in their comment letter [see pages 49 through 57 of the commenter’s letter], including:

- Removing transmission and storage equipment from the source category definition was arbitrary and capricious. The commenter asserts that the EPA properly determined in the NSPS OOOOa rulemaking that the 1979 source category listing was broad enough to encompass transmission and storage equipment in addition to production and processing equipment. plant. Even in the absence of the CRA resolution, the commenter states that the EPA would have been obligated to rectify the Policy Rule’s flaws and revert to the source category definition that appeared in the NSPS OOOOa rule. Congress clearly agreed, explaining in the House Report accompanying the CRA resolution that in NSPS OOOOa, EPA had “correctly” judged that the interrelated nature of the upstream and

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<sup>33</sup> 42 U.S.C. § 7607(9)(a).

<sup>34</sup> Env. Def. Fund, et al., Comments on Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review, Dkt. No. EPA-HQ-OAR-2017-0757-2134, at 18-43 (discussing exclusion of downstream sources from source category), 43-90 (discussing withdrawal of methane standards) (Nov. 25, 2019).

downstream segments and the general similarity of equipment across the segments justified a single source category.<sup>35</sup>

- Withdrawing methane standards for the oil and gas sector was arbitrary and capricious.
  - NSPS OOOOa's methane standards are not redundant. When confronted with the fact that, by its own logic, the oil and gas VOC standards were no less redundant than methane standards and could be rescinded without affecting EPA's obligation to issue existing source guidelines for the sector, EPA demurred that VOC standards should remain on the books because they were in place first and that "the decision of which NSPS to retain should not turn on the impact on existing sources," once again ignoring the massive environmental consequences of its decision. As described in the House report accompanying the CRA resolution, "the [Policy] Rule's misinterpretation of section 111 was glaring and enormously consequential" for ignoring the impacts on existing source emissions,<sup>36</sup> and was thus arbitrary and capricious.
  - NSPS OOOOa's "significance" finding for oil and gas methane emissions is neither flawed nor required to justify the rule's methane standards. The Policy Rule's interpretation of section 111 as additional pollutant-specific SCFs in order for EPA to regulate new pollutants from a previously-listed source category thus contravenes the basic language of the statute. The House Report accompanying the CRA resolution asserts that [t]he plain language of section 111 does not support this interpretation. The EPA's statutory interpretation prior to the [Policy Rule] is correct and would be reinstated by this resolution of disapproval. This action reaffirms that once a source category is listed, regulation of any pollutant is reasonable provided that the EPA has a rational basis for concluding that regulation is appropriate to address dangerous air pollution."<sup>37</sup>
  - No reliance interests on the deregulatory effects arose as a result of the Methane Policy Rule. Apart from the brief interlude between the time that EPA finalized the Policy Rule and the new administration took office and issued Executive Order 13,390, oil and gas operators have either had to comply with NSPS OOOOa in its entirety or have been on clear notice not only that NSPS OOOOa would likely be reinstated, but that stronger emissions standards—including requirements for existing sources—would likely be established by EPA. Any reliance interests that oil and gas operators may have had on the deregulatory effects of the Policy Rule are thus misplaced and should play no role in EPA's regulatory design of the NSPS OOOOb and c rules.

Similarly, commenter (0458-MDE) further supports the joint resolution under the CRA that disapproved the relaxations in the 2020 Policy Rule. The commenter states that they understand that much of the requirements from the 2016 Standard have been reinstated and are back into effect upon the enactment of the joint resolution. Any new, modified, or reconstructed facility

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<sup>35</sup> H. Rep. No. 117-64 at 24.

<sup>36</sup> H. Rep. No. 117-64 at 26.

<sup>37</sup> H. Rep. No. 117-64 at 28.

that would have been subject to the 2016 Standard, but for the 2020 Policy Rule, will immediately become subject to the 2016 Standard.

Commenter (1294-Ohio Clinicians for Climate Action (OCCA)) notes that it is appropriate for the EPA to heed the joint resolution of Congress adopted on June 30, 2021, under the CRA, and to disapprove the EPA's final rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review," Sept. 14, 2020 ("2020 Policy Rule"). The commenter states that this is responsive to the President's January 20, 2021, Executive Order titled "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis."

Commenter (0610-Occidental (Oxy)) supports regulation of methane emissions from new and existing oil and gas operations and notes that their President and CEO Vicki Hollub testified in April 2021 before the Senate Energy and Natural Resources Committee in support of invoking the CRA to recognize EPA's authority to regulate methane. The commenter provides that they work with external stakeholders at the state and federal level to advocate for environmentally sound methane regulations that achieve methane emission reductions, incentivize early action, and support flexibility and innovation.

Commenter (0926-Austin *et al.*) provides that their companies agree with EPA's interpretation of Congressional action under the CRA that it must regulate methane emissions across the oil and gas sector, including emissions from the transmission and storage segment, and support EPA's development of EG for states to implement existing source regulations. The commenter states that their companies see methane emission reductions as a critical component to addressing climate change and meeting the emission reduction goals established by the Biden-Harris Administration.

Commenter (1423-Congressman Donald S. Beyer (Beyer) *et al.*, 1434-Senator Martin Heinrich (Heinrich) *et al.*) states that the EPA's November 2021 Proposal strengthens and modernizes rules adopted in 2016 for new and modified oil and gas facilities and builds upon the bipartisan CRA resolution (H.J.Res.34, S.J.Res.14), enacted by Congress and signed by the President, with support from the oil and gas industry and electric utilities, to restore federal methane protections and regulation of oil and gas operations.

Response I-3-9: These comments are generally consistent with the positions the EPA has adopted in the preamble. No further response is needed.

### **3.5 Regulatory Certainty**

Comment: Commenter (0921-U.S. Chamber of Commerce) asserts that, in the development of regulations for new and existing sources, it is critical that EPA create regulatory standards that are well grounded in the authority of the statute to minimize the possibility that either a court would set aside aspects of the regulations or a future presidential administration would be inclined to revisit them. The commenter suggests that the EPA can achieve this kind of durability only by staying within the clear statutory authority conferred under the CAA and by avoiding

overreach – abstaining from attempting novel or untested legal approaches and from overreading the mandate of the CRA resolution that disapproved the prior 2020 Policy Rule.<sup>38</sup>

Commenter (0820-Pioneer Natural Resources USA, Inc. (Pioneer)) supports EPA’s November 2021 Proposal to rescind the 2020 Policy Rule and states that a clear regulatory program would provide operators with certainty and predictability in their capital spending, strategic planning and operations. The commenter adds that sensible methane regulation that balances the benefits of domestic oil and gas production with environmental protection is necessary to elevate natural gas as a clean energy solution, thereby strategically positioning this valuable resource for growth and viability in the future. The commenter suggests that the optimum result would be reasonable regulations that will incentivize early action, drive performance improvements, facilitate proper enforcement, support operational flexibility, and encourage technological innovation, particularly in the rapidly evolving area of methane leak detection, now and in the future.

Response I-3-10: The EPA believes that the legal interpretations, policy positions, and determinations made in this action achieve the goals of certainty and predictability that the commenters recommend.

### **3.6 Outdated Text in the CFR**

Comment: Commenter (0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ)) states that the EPA outlines the legislative history of the CRA joint resolution to disapprove the 2020 Policy Rule on page 63149 of the November 2021 Proposal. The CRA joint resolution was signed into law by President Biden on June 30, 2021. The CRA joint resolution disapproved the 2020 Policy Rule, and therefore the 2020 Policy Rule is treated as though it had never taken effect. 86 Fed. Reg. 63149 (citing 5 U.S.C. 801(f)). However, the commenter notes that the rule text of the 2020 Policy Rule remains in the CFR, even though its provisions are no longer in effect due to the CRA joint resolution. According to the commenter, this disparity between the rules currently in effect after passage of the CRA joint resolution and the outdated rule language that remains in the text of the CFR creates confusion for both the regulated community and regulatory agencies, and especially members of the public who may be unaware of the CRA joint resolution. The commenter asserts that regulatory clarity is needed immediately to reduce confusion and potential for error in compliance with and enforcement of the correct rule text.

Response I-3-11: The EPA is finalizing amendments to the CFR necessary to reflect the CRA joint resolution of disapproval of the 2020 Policy Rule.

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<sup>38</sup> See Joint Resolution, Pub. L. No. 117–23, 135 Stat. 295 (2021); see also H.R. Rep No. 117-64 (2021); and EPA’s “Legal Basis for Proposal Scope”, 86 Fed. Reg. at 63,147-53.

## Chapter 4. Overview of BSER, Control and Control Costs

### 4.1 Control of Methane and VOC Emissions in the Crude Oil and Natural Gas Source Category

#### 4.1.1 *Best System of Emission Reduction (BSER)*

##### 4.1.1.1 Periodic Revisions to BSER

Comment: Commenter (0746-Methane Action) requests that EPA provide a process for annually revising the list of “best systems of emission reduction” for each source to expedite the use of rapidly developing methods of removing methane from both near the source and further from sources. By way of example, the commenter provides a summary of descriptions of methods, based on recent articles coauthored by Methane Action Board Member Professor Rob Jackson of Stanford and consulting scientist Dr. Renaud de Richter, that they suggest warrant further research and development and cost effectiveness estimates for their implementation.

Response I-4-1: CAA section 111(b)(1)(B) requires the EPA to “at least every 8 years review and, if appropriate, revise” performance standards. As indicated by the “at least,” this provision does not prohibit the EPA from conducting such reviews more frequently than every 8 years. However, while the EPA recognizes that methods to reduce (or eliminate) methane emissions continue to emerge, the suggested annual reviews of BSER is impractical.

The EPA points out that there are aspects of the final rule that recognize and accommodate emerging technologies. For example, for those associated gas wells that are allowed to routinely flare emission due to a demonstration of technical infeasibility, owners and operators are required to re-evaluate the situation each year to determine if options have become available that would allow the gas to be used in a beneficial manner (i.e. not flared). Also, the rule includes provisions to allow the use of emerging technologies to identify fugitive methane leaks if owners and operators follow the prescribed approval processes.

##### 4.1.1.2 Use of Non-Combustion Devices and Innovative Technologies

Comment: Commenter (0601-Connecticut Department of Energy and Environmental Protection (CT DEEP)) suggests that EPA give priority to non-emitting controls or means for recovering emissions as an alternative to combustion controls. The commenter explains that while combustion control of natural gas, such as thermal oxidizers and flares, results in reduction of VOC and methane, they usually create emissions of nitrogen oxides and carbon dioxide, which are inconsistent with ozone attainment and climate change goals for many states, including Connecticut [their state].

Response I-4-2: In evaluating BSER for the various sources of emissions in the oil and natural gas industry, EPA included numerous types of non-combustion technologies, many of which totally eliminate methane emissions. The EPA must abide by the requirements in CAA section 111 to select BSER as systems that are adequately demonstrated, taking into account the costs

and any nonair quality health and environmental impact and energy requirements. For numerous emission sources covered by NSPS OOOOb and EG OOOOc, the BSER was determined to be systems that do not include combustion. Examples include programs to identify and repair fugitive leaks, zero-emitting process controllers and pumps, and routing associated gas to a sales line or using it for another beneficial purpose.

Comment: Commenter (0594-Huntsman Corporation) requests that EPA consider structuring the rule such that methane pyrolysis expressly qualifies for “useful purpose.” The commenter explains that doing so would achieve the agency’s goal of reducing flaring and beneficially using the gas while achieving additional benefits beyond reducing methane emissions. The commenter offered to work with EPA to craft a definition that facilitates the use of methane pyrolysis to generate an environmentally friendly material and significantly reduce methane emissions.

Response I-4-3: In the December 2022 Supplemental Proposal, methane pyrolysis was specifically included in the rule as one example of “another useful purpose” for which associated gas would be allowed to be used. While EPA still considers it to be an acceptable option, the final rule removed all specific examples. See section XI.2.g of the final rule preamble for more discussion of this topic.

Comment: Commenter (0594-Huntsman Corporation) requests that the EPA tailor the November 2021 Proposal to encourage the use of innovative technologies, such that EPA can ensure that participants not only meet the proposed standards for emission reduction but may have opportunities to generate advanced materials that leverages further greenhouse gas (GHG) emission reductions. By way of example, the commenter describes their Miralon® advanced carbon materials which are produced from methane gas using a form of methane pyrolysis to break down the carbon in methane into a carbon nanomaterial, while also creating a clean hydrogen fuel. The commenter states that to date, the process has achieved 80-90 percent single-pass efficiencies converting methane into carbon and can achieve far higher conversion (greater than 99 percent) with multiple passes. The commenter believes that their methane conversion technology is uniquely positioned to advance efforts to address the increasing rates of methane emissions and harmful resulting impacts, including CO<sub>2</sub> emissions from flaring. Regarding innovative technologies, the commenter explains that section 111(j) of the Clean Air Act (CAA) provides a direct route for use of advanced technologies by creating a pathway for persons to request an EPA waiver from the requirements of a standard of performance in order to “encourage the use of an innovative technological system or systems of continuous emission reduction” and believes their methane pyrolysis technology fits within four factors<sup>1</sup> the Administrator should consider when determining if the waiver is appropriate.

The commenter (0594-Huntsman Corporation) encourages EPA to provide an opportunity for entities to apply for such waivers. Further, the commenter explains that CAA 111(j) is not the only avenue which EPA can use to consider innovation, especially since the waiver process involves more lead-time given the requirements for a notice and comment period and occurs after the standard of performance is established. The commenter references the D.C. Circuit Court of Appeals conclusion that “[w]e do not believe that EPA is precluded from encouraging

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<sup>1</sup> 42 USC § 7411(j)(1)(A)(i) through (iv); 40 USC § 7411(j)(1)(A); *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir., 1981).

technological innovation through [new source performance standards] NSPS either because section 111(a) prohibits the agency from doing so or because section 111(j) is meant to be the exclusive statutory mechanism for promoting new methods of pollution control.” To the contrary, the commenter explains, Congress was concerned “that the NSPS should not stymie technological innovation.” The commenter provides examples of pathways which were used by EPA in the past (*e.g.*, a commercial demonstration permit in the context of coal and oil-fired electric utility steam generating units) and requests that the final rule open the door for more flexible standards for entities that seek permits for commercial demonstration of innovative technologies.

Commenter (0921-U.S. Chamber of Commerce) states that the November 2021 proposed emissions standards must allow for innovation and not limit compliance to certain technologies. Commenter (0831-American Exploration and Production Council (AXPC)) suggests that the regulation of methane should encourage innovation and flexibility, instead of command-and-control regulations that hinder the goal of reducing methane emissions; allow and incentivize the development and deployment of technologies to monitor and mitigate methane emissions for compliance purposes; appropriately quantify and assess the feasibility, costs and benefits of implementing new requirements for existing facilities; avoid creating duplicative and overlapping regulatory regimes at the federal and state levels; and properly interpret and follow the relevant provisions of the CAA.

Response I-4-4: NSPS OOOOb and EG OOOOc provide clear and enforceable requirements, while also balancing the consideration of innovation and flexibility. Many of the final standards and presumptive standards are structured in a manner that provides owners and operators numerous options for compliance. They also are structured in a manner that will allow for the use of emerging technologies and solutions that are developed in the future. For example, the process controller standards in NSPS OOOOb and EG OOOOc require “zero emissions.” Owners and operators can utilize a variety of types of currently available controllers to meet the specific needs of the site, ranging from electric controllers to controllers powered by compressed air.

## **4.2 Control Costs of Standards**

### ***4.2.1 Natural Gas Savings***

Comment: Commenters (0755-Texas Pipeline Association (TPA), 0817-GPA Midstream Association (GPA)) state that EPA’s assumptions that certain sectors will recover revenue based on natural gas saved through methane reductions is incorrect. Commenter (0755-TPA) states that in EPA’s consideration of the costs and benefits of the November 2021 Proposal, EPA takes the position that costs of increased emission controls on regulated parties will be offset by increased revenue due to reduced leakage and reduced venting - *i.e.*, less product will escape so more product can be sold, resulting in increased revenue. The commenter states that this calculus is inappropriate, however, where the company in question does not own the gas, because a company that does not own a product receives no increase in revenue when that product is sold. The commenter urges EPA to ensure that any such revenue increase projections are not attributed to operations where the company in question does not own the gas being handled or

transported. The commenter offers to work with EPA to help precisely identify the types of operations that should be excluded in EPA's projections of increased revenue. Similarly, commenter (0817-GPA) states that in several sections of the preamble, Regulatory Impacts Analysis (RIA), and Technical Support Document (TSD), EPA asserts that facilities in the gathering and boosting (G&B) and natural gas processing segments own the natural gas in their systems and that reducing gas leakage will offset emission control costs, but the commenter states that this assumption is incorrect. Instead, the commenter states that owners and operators in the G&B and processing segments are paid a transportation fee to move and prepare the natural gas for delivery into an interstate pipeline system. The commenter further explains that this transportation fee is assessed even in larger integrated companies that own the upstream production facilities and midstream G&B and processing facilities as they are typically set up as separate business units. The commenter urges EPA to correct its cost estimates to note that the regulated entities will receive no monetary benefit from any natural gas saved because of the November 2021 Proposal. Further, the commenter requests that EPA understand that the costs of new regulation may be passed through to upstream entities via increased transportation fees, depending upon contract terms and the parties' respective business interests. For these reasons, the commenter recommends that EPA reassess its cost-benefit analyses to omit cost savings from recovered gas for the G&B and processing segments.

Response I-4-5: The commenter contends that because some companies in the gathering and boosting segment do not own the gas that they are transporting, the revenues from natural gas recovery should not be included as an offset to compliance costs in this segment. EPA agrees that affected sources may not own recovered product, but disagrees regarding the treatment of product recovery for estimating national costs. From a social perspective, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and thus, should be accounted for in the national impacts analysis. From an economic perspective, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents.

In addition, while the EPA's analyses calculated the volume of natural gas savings and their impacts on the annual costs, all the final BSERs were determined to be cost effective without consideration of those natural gas savings. In other words, BSER determinations were not impacted by assumptions regarding natural gas savings.

#### ***4.2.2 Cumulative Impact of All Oil and Natural Gas Sector Regulatory and Policy Actions***

Comment: Commenter (0821-Xcel Energy, Inc. (Xcel)) cautions the EPA that the cumulative impact of all regulatory and policy actions taken to reduce emissions from the oil and natural gas sector be considered and that actions taken should be complementary and avoid unnecessary increases in cost while reducing emissions. The commenter states that it would be contrary to the objective of significantly reducing the nation's GHG emissions if overregulation inadvertently advantaged coal over natural gas for electric generation.



Response I-4-6: The standards included in the final NSPS OOOOb and the presumptive standards in EG OOOOc were developed in accordance with the statutory requirements in Section 111 of the CAA. Consistent with Executive Order 12866, RIAs accompanying the November 2021 Proposed Rule, December 2022 Supplemental Rule, and the Final Rule all appropriately evaluate the regulatory impacts of the NSPS OOOOb and EG OOOOc regulatory actions.

Comments on the impacts of the other regulatory actions mentioned by the commenter are out of scope for this response to comments document. However, the EPA notes that we are developing emissions standards for GHG emissions from coal-fired electric utilities in a separate action under Section 111 of the CAA. (see 88 FR 33240, May 23, 2023).

#### ***4.2.3 Cost Effectiveness Threshold for Methane***

Comment: Commenters (0834-Air Advocacy Coalition (A2C), 0808-American Petroleum Institute (API)) request that EPA better explain the rationale and provide factual support for the November 2021 proposed \$1,800/ton cost effectiveness threshold for methane. Commenter (0834-A2C) states that EPA is required, in proposed and final CAA rules, to prepare a statement of basis and purpose that includes, among other things, the “factual data” on which the rule is based.<sup>2</sup> The commenter states that this is consistent with EPA’s more fundamental obligation in conducting rulemaking to “examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.”<sup>3</sup>

Commenter (0808-API) states that the only justification that the EPA presents for using a methane cost effectiveness threshold of \$1,800/ton is that the Agency used a similar methane cost effectiveness threshold in the 2016 NSPS OOOOa rule; this commenter contends that a “because we did it before” justification is inadequate. Instead, the commenter argues, CAA section 111 requires that EPA develop a record to support its determination that the NSPS standards “represent[] the best balance of economic, environmental, and energy considerations.” Further, the commenter states that an agency action is arbitrary and capricious if it does not “examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made.” Instead, the commenter asserts, in the November 2021 Proposal EPA fails to meet these standards because it presents essentially no “relevant data” to support its proposed cost effectiveness threshold and, because of that, EPA cannot and does not explain how the “relevant data” inform the choice of \$1,800/ton. The commenter surmises, for example, that perhaps EPA believes that using values up to \$2,185/ton in the 2016 rule provides evidence that values in this range are acceptable in the November 2021 Proposal because the 2016 rule has been widely implemented across the affected industry. If this is what EPA believes, it should have said so, but they do not believe that EPA explained this. Moreover, the commenter states that EPA has made no effort in the current rule to show why \$2,185/ton is an appropriate touchstone, beyond simply asserting it to be true. The commenter believes that failure to present “relevant data” and to explain how those data inform the November 2021 Proposal fundamentally undermines the proposed value of \$1,800/ton. Lastly, the commenter explains that EPA’s factual determinations must be

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<sup>2</sup> CAA § 307(d)(3)(A).

<sup>3</sup> *Motor Vehicle Mfrs. Ass’n v. State Farm*, 463 U.S. 29, 43 (1983).

“supported by substantial evidence when considered on the record as a whole,” but contends that the \$1,800/ton threshold is supported by no evidence at all, much less substantial evidence.<sup>4</sup>

Response I-4-7: Section VIII.B of the Final Rule presents a detailed discussion of how EPA considered control costs in this action. It includes a description of the information that the EPA relied upon in formulating its cost effectiveness analyses, an explanation of the methodology of, and rationale behind, the analyses, and a discussion of why the final BSER for each emission source is reasonable through the lens of a cost effectiveness analysis.

EPA disagrees with the contention by Commenter (0808-API) that the record for this rulemaking does not include factual support, relevant data, and rationale. The EPA provided technical support documents for the November 2021 Proposed Rule and the December 2022 Supplemental Proposal, and they were further updated for the Final Rule. In each instance, the EPA has provided not only the technical support documents, but also Excel workbooks detailing the underlying data and analyses. In the three Federal Register preambles, EPA has also explained its analyses of control options and the selected BSER in great detail.

The EPA also notes that cost effectiveness, and the reasonableness of any particular cost effectiveness value, is only one piece of EPA’s consideration of BSER. Specifically, as explained in detail in Section VIII.B of the Final Rule, the EPA conducted additional cost analyses that each separately reinforce the reasonableness of the final standards.

#### ***4.2.4 Existing State Programs as a Basis for National Standards***

Comment: Commenters (0935-Colorado Oil and Gas Association (COGA), 0797-North Dakota Department of Environmental Quality (NDDEQ) and North Dakota Industrial Commission (NDIC)) have concerns with using existing state programs as the basis for national standards. Commenter (0935-COGA) states that EPA must provide evidence supporting the anticipated standards, specifically when citing state regulations as reasonable for national standards. The commenter states that CAA section 111 has its own criteria which the Administrator must evaluate before establishing federal NSPS or requiring states to submit plans establishing standards of performance for existing sources.<sup>5</sup> The commenter explains that a state regulation may not be constrained in the same manner as CAA section 111, and the state may be willing to impose costs that are not reasonable elsewhere. Therefore, the commenter argues, statements from EPA that assume that if a state agency found a particular regulation to be appropriate for its own state, the costs must be reasonable for nationwide application and the degree of emission limitation under consideration must be achievable through application of the BSER, are unwarranted. The commenter states that Colorado is an example of this, where the state’s extremely stringent oil and gas regulations were promulgated in response to unique local conditions and state statutes; the commenter argues that the EPA should analyze the anticipated

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<sup>4</sup> *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981); *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983); *New Jersey v. EPA*, 517 F. 3d 574, 583; *Coalition for Responsible Regulation v. EPA*, 684 F. 3d 102, 122 (D.C. Cir. 2012).

<sup>5</sup> 42 U.S.C. §§ 7411(b)(1)(B) and (d)(1).

standards' costs and benefits through a national lens and determine whether the national costs are reasonable.

Commenter (0797-NDDEQ/NDIC) contends that the conclusion that California (CA) and Colorado (CO) are good and representative models for the costs of the November 2021 Proposal and as the baseline to evaluate other state programs is arbitrary and fails to consider the actual oil and gas production sector in the United States. By way of example, the commenter notes that ND is ranked third in the U.S. among all states in the production of oil and gas, just behind Texas (TX) and New Mexico (NM). The commenter states that those three states account for over 60 percent of the oil and gas production nationwide, whereas CO and CA are ranked fifth and seventh respectively, accounting for just 8 percent of total production volumes in the U.S.<sup>6</sup> and for this reason, ND, TX, and NM are better and more representative baselines for evaluating the November 2021 Proposal. The commenter also points out that CA and CO have air quality issues which have forced these states to implement increasingly stringent air emission requirements that have still failed to achieve attainment with air quality standards. These circumstances, the commenter says, along with their much higher populations, do not make them representative of other states or relevant for determining the costs other states might incur in implementing EPA's proposal. The commenter believes that EPA cannot fairly characterize the costs in the absence of an actual proposed rule, and in any event has underestimated the compliance costs that states will incur in developing the required emissions guidelines (EG) plans for OOOOc. Further, the commenter states that the RIA does not appear to have sufficient data to accurately calculate these costs and that the baseline data is biased. The commenter contends that, overall, in both the November 2021 Proposal and related RIA, the EPA downplays the burden of developing the EG OOOOc state plans.

Response I-4-8: The EPA did review and consult a number of state regulations and programs during the development of NSPS OOOOb and EG OOOOc. These included not only Colorado and California, but also North Dakota, Texas, New Mexico, Pennsylvania, Ohio, Wyoming, and other states. While EPA looked to these state regulations and programs to identify strategies and control options that have been successfully implemented, EPA did not presume that a measure appropriate for a given state was necessarily suitable for nationwide implementation.

With regard to the argument by Commenter (0797-NDDEQ/NDIC) that the EPA should "analyze the anticipated standards' costs and benefits through a national lens and determine whether the national costs are reasonable," the EPA is not required to undertake a formal cost-benefit analysis, as explained in further detail in Section VIII.B of the Final Rule. EPA performed independent and comprehensive cost analyses in accordance with the requirements of section 111 of the CAA, as explained in detail in Section VIII.B. In a few very limited instances EPA used cost information from a state's technical support analyses, but relied upon a number of different sources, including substantial information provided by the regulated industry, in its BSER analyses of the capital and annual costs of control measures considered.

Regarding statements by Commenter (0797-NDDEQ/NDIC) that the EPA has downplayed or underestimated the burdens on states of developing EG OOOOc state plans, the EPA notes that the Information Collection Request (ICR) and supporting statement for the November 2021

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<sup>6</sup> U.S. Energy Information Administration, at <https://www.eia.gov/state/rankings/?sid=US#/series/46>.

Proposed Rule included estimates of the time and resources necessary for state agencies to develop EG OOOOc state plans, but the commenter did not provide any specific comments on that analysis. These cost impacts on state agencies are also contained in the ICR and supporting statements for the December 2022 supplemental proposal and the final rule. With regard to EPA's estimated burden for states to develop EG OOOOc state plans, see the ICR Supporting Statements located at Document ID Item Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO and NSPS OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc), for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

#### ***4.2.5 Collaboration with States***

Comment: Commenter (0797-NDDEQ/NDIC) suggests that EPA is missing opportunities to decrease burden, such as focusing on ways to collaborate with states to invest in cost-effective improvements to emissions control program implementation and enforcement to achieve performance improvements. By way of example, the commenter cited the first optical gas imaging camera used by ND, which was obtained with the assistance of an EPA grant and has dramatically changed how ND conducts its inspections of the oil and natural gas sector.

Response I-4-9: As noted in response I-4-8, the EPA considered the elements of numerous state programs during the development of NSPS OOOOb and EG OOOOc. Regarding the specific instance cited by the commenter, the use of optical gas imaging is a fundamental aspect of the final rule.

Comment: Commenter (0957-Wyoming Coalition of Local Governments (WCLG)) states that many states, including Wyoming, have made extensive efforts to regulate emission sources within their respective borders, and asserts that oil and gas companies should not be subject to duplicative state and federal regulatory requirements due to the adoption of the EPA's November 2021 Proposal. The commenter adds that there is little recognition of the state regulatory measures that link air quality standards to operational regulation, which the commenter believes to be a major omission in the November 2021 Proposal.

Response I-4-10: EPA acknowledges the efforts undertaken by states such as Wyoming to regulate emissions from the oil and natural gas industry and, as discussed in Response I-4-8, considered the advancements in these state regulations in the development of NSPS OOOOb and EG OOOOc. The EG OOOOc were developed pursuant to CAA section 111(d) and EPA's implementing regulations at 40 CFR Part 60 Subpart Ba, which includes specific requirements for emission guidelines. When states develop their state plans in accordance with EG OOOOc, they have the ability to do so in a manner that reduces regulatory duplication. For further detail, see Section V.A of the 2022 Supplemental Proposal preamble and Section VI.A of the Final Rule preamble. When developing these emission guidelines, the EPA gave specific consideration to the fact that some states already have existing regulations in place for the oil and natural gas industry. See Section XIII.C.2 within the final rule preamble. This section titled "state flexibilities" discusses issues relevant to this comment such as leveraging an existing program for state plan submittal purposes and averaging.

#### ***4.2.6 Unquantified and Ancillary Benefits***

Comment: Commenter (0761-Exelon Corporation (Exelon)) recommends that EPA consider unquantified and ancillary benefits in the rulemaking. According to the commenter, economic principles and best practices for agency rulemaking dictate that consideration of costs and benefits of any CAA section 111 rule include all quantifiable and unquantifiable, direct and indirect costs and benefits. The commenter states that Executive Order (E.O.) 12866 governing agency rulemaking provides that “agencies should assess all costs and benefits” of proposed regulatory actions, and, for “significant regulatory actions,” must assess “benefits anticipated from the regulatory action (such as, but not limited to, the promotion of the efficient functioning of the economy and private markets, the enhancement of health and safety, the protection of the natural environment, and the elimination or reduction of discrimination or bias).” Similarly, the commenter references guidance from the Office of Management and Budget (OMB) which directs agencies to “look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking...” Further, the commenter argues, EPA’s long-standing practice is to include in a cost-benefit analysis benefits that are not directly intended by the rulemaking.<sup>7</sup>

Response I-4-11: The EPA has met the requirements of CAA section 111 and EO 12866. The commenter did not provide specific examples of the unquantified and ancillary benefits that it believes are missing from the EPA’s analyses. For more information, see Section XVI of the Final Rule preamble and the RIA for the Final Rule.

#### ***4.2.7 Other Cost Benefit Analysis Methodology Comments***

Comment: Commenter (0326-Driss Lonqueux (Lonqueux)) recommends that EPA determine the kinds of controls that are technologically and economically viable for producers by providing a transparent cost-benefit analysis and setting technology-based standards. The commenter states that the first step to mitigate uncertainties is to publish a microeconomic cost-benefit analysis to provide the unit economics of flaring versus capture and sales. Commenter (0326-Lonqueux) states that the November 2021 Proposal fails to promote emerging technologies that have already met EPA screening criteria (compressed natural gas (CNG) trucking, natural gas liquid (NGL) recovery, gas-to-power). The profitability of each technology depends on identifiable factors such as production volumes, gas composition, and distance between wells, and processing plants.

Response I-4-12: The EPA developed the technology-based emission standards in NSPS OOOOb and EG OOOOc using a transparent cost analysis in accordance with the requirements of CAA section 111. The EPA established standards that represent BSER based on the currently available emission reduction techniques, but that are flexible enough to allow the use of emerging technologies. The EPA did not specifically evaluate costs for the emerging technologies mentioned by the commenter. However, these are specifically options that are allowed to be used to comply with the final standards and presumptive standards. For example,

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<sup>7</sup> U.S. White House Office of Management and Budget, Circular A-4 (Sept. 17, 2003), [https://obamawhitehouse.archives.gov/omb/circulars\\_a004\\_a-4/](https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/); U.S. Environmental Protection Agency, EPA’s Guidelines for Preparing Economic Analyses (Dec. 17, 2010)), <https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses>.

for associated gas wells, the final NSPS OOOOb requires that the associated gas be either (1) routed into a gas gathering flow line or collection system to a sales line, (2) used as an onsite fuel source, (3) used for another useful purpose that a purchased fuel or raw material would serve, or (4) injected or reinjected. Under the third option, CNG trucking, NGL recovery, and gas-to-power are all acceptable compliance methods.

Comment: Commenter (1388-Private Citizen) states that the rule does not go far enough in reducing methane and pollutant emissions and recommends more stringent controls with a goal of zero (prohibited) emissions in the future. The commenter states that these more robust restrictions are needed because the 2023–2035 time frame for comparing cost versus benefits is too short. The commenter states that the cost of mitigating climate change will be much greater in the future, well beyond 2035, when the negative impacts of climate change will be much more devastating and cost us much more in our attempts for mitigation, whereas the cost to the facility is mostly upfront and immediate with some minor costs from testing extending for the life of the facility. The commenter further states that health care costs from industry pollutant emissions and associated loss of productivity for diseases that are instigated now but don't progress to critical stage until many years later, support a longer time frame for determining the cost benefit analysis. The commenter recommends that the cost-benefit analysis be computed for at least the next 100 years.

Response I-4-13: The EPA extended the analysis horizon beyond 2035 to 2038 but declined to extend the analysis further due to the significant uncertainties in projected long-run sectoral trends. In addition, the EPA notes that the monetized climate benefits associated with the 2023–2038 CH<sub>4</sub> emission reductions reflects the discounted stream of benefits resulting from those emission reductions over a much longer time horizon (out to 2300). The commenter did not provide data to substantiate the assertion health care costs and loss of productivity support a longer time frame for the cost benefit analysis.

### **4.3 Compliance Costs**

Comment: Commenter (0600-Pacific Investment Management Company LLC (PIMCO)) states that acknowledging that the relative costs of compliance will vary given the size of the company, they overall view the costs as negligible. EPA estimates that the net cost of compliance would range from \$0.9 to \$1.5 billion on an annualized basis from 2026–2035 for the entire sector to address both new and existing sources. This accounts to 0.3 percent of annual sector capex estimates and about 0.2 percent of annual industry revenues.<sup>8</sup> For some companies, methane emissions abatement may be cost-neutral or lead to a long-term benefit as emissions which are captured can be sold.

Several commenters (0577-Kansas Independent Oil & Gas Association (KIOGA), 0824-Wyoming Department of Environmental Quality (WDEQ)) express concern that the November 2021 Proposal would impose requirements with potentially exorbitant costs for new and existing sources, but particularly for existing sources.

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<sup>8</sup> Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110, 63,157 (Proposed Nov. 15, 2021).

Commenter (0824-WDEQ) states that the new requirements in EG OOOOc (which establishes EG for existing sources) mirror many of the requirements in NSPS OOOOb. Put simply, the commenter contends that there are exorbitant and even infeasible costs associated with retrofitting certain control requirements on all existing sources considered affected facilities under the rule - and the definitions of such affected facilities have also been expanded for many different types of equipment. According to the commenter, the number of existing facilities in Wyoming that would have to undergo costly retrofitting procedures in addition to the increased monitoring and compliance burdens would be massive. At this time, it is impossible to know exactly what the economic impacts would be to operators and the feasibility of continuing their operations and retaining employees, but it is reasonable to assume that they would be significant.

Response I-4-14: As evidenced by this series of comments, the opinions of the public vary considerably regarding the impacts that the compliance costs will have on the industry. EPA maintains that the costs associated with the final NSPS OOOOb and EG OOOOc are reasonable taking into account emission reductions and any nonair quality health and environmental impact and energy requirements. See the discussions in section VII.C. of the December 2022 Supplemental Proposal and Section VIII.B of the Final Rule preamble related to how EPA considered control costs in this action.<sup>9</sup>

Comment: One commenter (0577-KIOGA) provided quotes for 95 percent combustion devices to meet compliance with this regulation. Certified combustion devices are more expensive than devices that do not carry the certification, which is contrary to the EPA's expectation that certified devices may be economically favorable. A certified combustion device that will meet gas flow rate requirements and gas quality will cost owners/operators \$12,000 – \$22,000 to purchase and an additional \$8,000 to install, for a total installed cost of \$20,000 – \$30,000 per well. A conventional oil well may cost \$300,000 to \$600,000 to drill and complete. Installation of a combustion system could add 5 percent to 10 percent to the total cost of the project. The additional compliance cost will eliminate projects from being implemented.

The commenter (0577-KIOGA) contends that compliance costs will be considerably greater than the estimates that have been provided by the EPA. The commenter states that the installation of a certified combustor will cost \$20,000 – \$30,000 and does not include the cost to purchase and install a separator, install piping, complete the required surveys, and complete the required reporting for each well that is drilled. The commenter estimates that the compliance costs could exceed 10 percent of the capital cost to drill a well. According to the commenter, these costs are significant and could drive many small operators out of business. The commenter disagrees with the EPA's assessment that the industry can bear the cost and survive.

In addition, the commenter (0577-KIOGA) adds that over the past several years, many small oil and gas companies in Kansas have been working to develop compliance programs to meet the requirements of NSPS OOOOa. The commenter provides a table [see below] of a sample of some of the compliance costs. According to the commenter, it is not a complete list of costs, but an example of some of the additional required activities and the costs associated with each

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<sup>9</sup> 87 FR 74842 (Dec. 6, 2022).

activity. According to the commenter, as the list of costs demonstrates, the cost of compliance negatively impacts small business.

| Activity                                                  | Cost                 | Frequency                     |
|-----------------------------------------------------------|----------------------|-------------------------------|
| VOC inspection of tank facility                           | \$500 - \$2,000      | 2x per year per facility/well |
| Documentation and record keeping                          | \$20,000 - \$100,000 | Annually                      |
| Green Completion (only for non-delineation wells)         | \$10,000 - \$15,000  | Every new exploration well    |
| Install sample fittings (parts and labor) for gas samples | \$500 - \$1,000      | Every new facility            |
| Laboratory analysis                                       | \$500 - \$1,000      | Every new facility            |
| Engineering evaluation of lab data analysis               | \$250 - \$500        | Every new facility            |
| PE Certification of combustion system                     | \$2,500 - \$3,000    | Every new facility            |
| Installation of combustion system                         | \$20,000 - \$40,000  | Every new facility            |
| Monthly inspection of combustion system                   | \$250 - \$500        | Monthly                       |
| Monthly inspection after removal of combustion system     | \$2,500 - 4,000      | Monthly                       |
| Design of combustion system                               | \$10,000 - \$15,000  | One time cost                 |
| Develop record keeping system                             | \$40,000 - \$50,000  | One time cost                 |
| Develop site specific monitoring plans                    | \$30,000 - \$50,000  | One time cost                 |
| Purchase FLIR camera                                      | \$95,000 - \$100,000 | One time cost                 |
| FLIR camera training                                      | \$3,000 - \$5,000    | One time cost                 |
| Purchase sample collection equipment                      | \$2,000 - \$5,000    | One time cost                 |

*Table 2. Compliance Activities and Costs Required by NSPS OOOOa*

**Response I-4-15:** The commenter appears to assume that a combustion device will be required to comply with NSPS OOOOb standards and EG OOOOc presumptive standards. This is not the case. In fact, for several emission sources the use of a combustion device that achieves 95 percent reduction is not allowed (e.g., process controllers) or allowed only in very limited circumstances (e.g., associated gas wells, pumps).

For the most part, the costs provided by the commenter are less than the estimates that EPA used in the BSER analyses. For example, for associated gas, the capital cost estimate used by EPA was just over \$100,000 and annual costs were \$36,000 per year. See the Final Rule TSD, Chapter 4.

**Comment:** Commenter (0577-KIOGA) states that they believe that EPA has underestimated the annual burden for recordkeeping and reporting requirements in NSPS OOOOa. The commenter provides information on compliance costs that are significantly higher than the estimates used by EPA in the November 2021 Proposal. The commenter suggests that the documentation required by the proposed regulation creates ample opportunities for any operator to be cited by EPA for missing information.

Commenter (0577-KIOGA) notes that EPA estimated that the average owner or operator will spend approximately 38 hours per year (98,438 labor hours/2,554 owners and operators), in the first three years, on compliance reporting activities. This time estimate is expected to cost the average owner \$1,316 per year (\$3,361,074 per year/2,554 owners and operators). The commenter estimates that a one-time cost to develop a management and reporting system to be \$40,000 - \$50,000 and an ongoing cost of compliance of \$20,000 - \$100,000 per year (one-part time employee early in the program and potentially two full time people within a few years). The commenter contends that the required information will be a substantial burden on small organizations to collect, manage, store, and report to the Agency on an annual basis. According to the commenter, this does not include the increase in operating costs that will come from Leak



Detection and Repair (LDAR) survey costs, reporting costs, and additional capital investment to meet emissions reductions.

The commenter (0577-KIOGA) adds that the documentation will necessitate many more hours than the EPA's estimated 38 hours per year. Companies are evaluating the need to hire another one to two people solely to meet the reporting requirements of this new regulation. The commenter believes that a full-time position(s) may be required to meet all of the annual reporting and data management requirements to maintain compliance. They estimate that the fully loaded cost (salary and benefits) to fill this position will be an additional \$50,000 – \$60,000 per year per person to current operations. These requirements are not trivial.

Commenter (0577-KIOGA) reports that some operators in Kansas may drill 200 oil wells and perform work that would meet the EPA's definition of a "modification" for more than 250 existing wells in a five-year period. This is an average of 90 wells being drilled or modified each year, not including associated tanks or other Fugitive Emissions Components. The commenter expects this level of activity to resume as oil prices increase for some of the active owners/operators in Kansas. The commenter adds that they believe that smaller owners/operators will reduce their drilling and maintenance programs until the oil price increases again. The reporting work will continue to grow each year as we continue to drill and modify wells because the current year work is added to all work from prior years. This growing workload will require the hiring of additional employees in the future.

Response I-4-16: The recordkeeping and reporting requirements for NSPS OOOOb are comparable to those in NSPS OOOOa, as are EPA's estimates of the associated burden. While this commenter has speculated about projected costs, it is notable that industry representatives that have been complying with NSPS OOOOa did not provide comments or information to indicate that their actual costs are significantly higher than EPA's estimates. See discussion in section VIII.B. of the December 2022 Supplemental Proposal related to information collection activities in the proposed amendments<sup>10</sup> and section XVII.B of the Final Rule preamble. Also see the ICR document that the EPA prepared, which has been assigned OMB Control No. 2060–0721 and EPA ICR number 2523.05.

Comment: Several commenters (0929-National Stripper Well Association (NSWA), 0585-Kentucky Oil and Gas Association (KOGA), 0425-Darrah Oil Company, LLC (Darrah)) state that the November 2021 Proposal as currently described will place an extreme financial burden on their members.

Commenter (0929-NSWA) asserts that this is especially troubling in a time when many of their members are beginning to recover, and adjust, from the economic impacts of the COVID pandemic and market turns. For example, the commenter notes that optical gas imaging (OGI) cameras required under the November 2021 Proposal can cost producers over \$100,000. These added costs are simply not feasible for smaller operations. In addition, the expensive one-time investments required by the proposed regulation and the additional documentation costs cannot be overlooked. Building new reporting systems is expensive and will come with additional increases in payroll costs as new employees will be needed to process all of the required

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<sup>10</sup> 87 FR 74844 (Dec. 6, 2022).

documentation. According to the commenter, smaller producers do not have the same economies of scale as larger producers and cannot spread increases in fixed compliance costs over as many projects. They contend that this will result in many of their members likely going out of business as they are unable to maintain profitability. The commenter states that the potential full costs of the rule are particularly disconcerting because the EPA often underestimates costs. Considering the cost estimates for monitoring tanks and wells the EPA has provided for low production wells, the monitoring cost alone will add an estimated 10 percent to 50 percent additional cost to the operating expenses (depending on the final monitoring frequency that is required). This, the commenter states, does not include all of the other costs associated with implementing the rule.

Commenter (0929-NSWA) notes that the November 2021 Proposal preamble does include a cost per inspection reported. The EPA estimated annual costs of the fugitive emissions program at well sites is estimated to range from \$2,490 for biennial monitoring to \$8,140 for monthly monitoring. To appreciate the impact, the commenter provides the following example: the typical marginal well produces approximately 1 barrel of oil per day. Using the EPA's cost estimates, biennial inspections required for the typical marginal well equates to \$6.82 / barrel of additional operating cost ( $\$2,490 \text{ for biennial inspections} / (1 \text{ barrel per day} \times 365 \text{ days per year}) = \$6.82/\text{barrel}$ ). Monthly monitoring cost is estimated to be \$22.30/barrel of additional operating cost ( $\$8,140 \text{ for monthly inspections} / (1 \text{ barrel per day} \times 365 \text{ days per year}) = \$22.30 / \text{barrel}$ ). When the typical operating cost for a marginal well is \$20 / barrel to \$40 / barrel, this is a significant increase to the operating cost just for the fugitive emissions monitoring program.

As an example, the commenter (0929-NSWA) provides that implementing a \$3,000/year program on a well that produces one barrel per day (below that is considered extremely low, the commenter assures us small operators produce a lot of wells at or near that level. The average per well output in Kansas was close to 1.6 billion barrels (Bbls) per day last year.) would cost that well \$8.22 per Bbl produced and likely condemn its ability to operate at a profit. The additional compliance cost will result in many of the marginal wells being permanently abandoned. The commenter states that the loss of production will result in higher energy costs for all Americans, job loss for oil and gas employees, and lost revenue for mineral owners.

Response I-4-17: See EPA responses in Volume I, Chapter 20, subsection 20.2.7 of this volume for responses to comments related to the impacts on small businesses and marginal producers.

Comment: Several commenters (0929-NSWA, 0585-KOGA, 0425-Darrah) state that the EPA provides several cost metrics in the preamble, based on the cost of emissions reductions (*i.e.*, dollars per ton). While this metric may be meaningful to the EPA staff, it is not meaningful to industry. They suggest that the EPA consider implementation costs of the rule in metrics that the industry uses, specifically cost per unit of production (*i.e.*, \$/million cubic feet (MCF) of gas or \$/barrel of oil). The commenters explain that these are the metrics that industry uses to make decisions, not dollars per ton of emissions reduced. According to one of the commenters (0929-NSWA), industry does not have a way to translate the EPA's cost estimates to validate their assumptions or understand how it will impact our businesses. The commenter suggests that the EPA also provide cost metrics based on the cost per inspection and cost per unit of production.

Response I-4-18: Section 111 of the CAA specifies that EPA must establish "the best system of emission reduction which (taking into account the cost of achieving such reduction and any

nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” Calculating a dollar per ton of reduction is a direct method of accounting for the cost of an emission reduction.

In some cases, the emissions, and thus the emission reductions, are directly related to a metric commonly used by the industry. For example, the amount of associated gas produced is directly proportional to the emissions and thus the emission reductions. Therefore, for a particular well it would be straightforward to calculate dollars per MCF of production. However, given the numerous differences from well to well, notably the amount of methane in the associated gas, the dollars per MCF of production would vary from well to well. In other instances, such as fugitive component leaks, correlations exist between the cost and the number of components to be monitored.

Comment: Commenter (0957-Wyoming Coalition of Local Governments (WYCLG)) notes that the EPA included a cost analysis for the technical and monitoring requirements in the November 2021 Proposal, but that the analyses addressed each individual requirement separately without a discussion as to the cumulative costs per well site to comply with all the new proposed requirements. For example, the November 2021 Proposal estimates the cost of implementing the proposed fugitive emissions monitoring guidelines at well sites and concludes that is cost effective. It also makes similar cost-effective conclusions on other proposed requirements to control emissions from equipment not previously regulated, such as tank batteries, which would require retrofitting of the necessary emission control equipment at existing well sites. The commenter states that individually the cost to comply with each proposed monitoring or technical requirement may be reasonable but it is no longer a reasonable cost when you consider the total costs of complying with all of the proposed monitoring requirements and emissions standards. The commenter emphasizes that this is especially true for smaller businesses and those that operate lower producing wells.

Response I-4-19: As has been stressed by the industry throughout the development of NSPS OOOOb and EG OOOOc, and prior to that during the development of NSPS OOOO and OOOOa, there is considerable variation in the equipment and processes at oil and natural gas production sites. Therefore, the overall site-wide cost will vary substantially from site to site, which would make it difficult to evaluate site-wide costs for representative facilities.

However, a key metric that the EPA used in determining BSER for the covered emissions sources is the cost per unit of emission reduction, or cost effectiveness (e.g., dollars per ton of methane or VOC emissions reduced or eliminated). If the cost effectiveness of the requirements for every individual emission source (affected facility or designated facility) is reasonable, then the collective cost effectiveness must also be reasonable.

While the BSER analyses and decisions were on an emission source basis, the regulatory impact analysis does consider the collective costs of all measures and the impacts on businesses. See the RIA for the Final Rule for more information. In addition, the EPA considered costs of compliance on industry as a whole, as explained in further detail in Section VIII of the Final Rule preamble.

Comment: Commenter (1301-Northern Arapaho Tribe Business Council (NATBC)) requests that the EPA provide additional detail about the costs of complying with new measures under the November 2021 Proposal at a useful scale, including the likely range of costs for:

- Quarterly monitoring of major well sites and compressor stations
- Surveying of smaller well sites
- Routing associated gas to flare or control devices that meet 95 percent reduction Rule requirement
- Reducing tank and tank battery emissions to meet 95 percent reduction Rule requirement
- Replacement of pneumatic pumps and pneumatic controllers to meet 95 percent to 100 percent reduction Rule requirements, respectively

The commenter (1301-NATBC) states that the November 2021 Proposal currently provides only a very brief, two-paragraph summary regarding compliance costs, offering merely an estimated aggregate present value compliance cost of “\$13 billion” between 2023-2035. That projected overall estimate is not helpful to the commenter in assessing the likely cost burden of bringing individual petroleum and natural gas operations into compliance with the numerous distinct requirements of the November 2021 Proposal.

The commenter (1301-NATBC) asserts that more granular examples and information would be helpful. For example, our understanding is that a single industry-grade handheld Forward Looking InfraRed (FLIR) thermal imaging camera used for gas leak detection costs \$13,000-\$55,000 depending on the model. Under the November 2021 Proposal, operators will have to purchase or rent such equipment to conduct mandatory monitoring and surveying of well sites. Because thermal imaging is likely to detect leaks not typically detected by visual inspections, maintenance costs are also likely to increase. The commenter notes that there will also be additional costs associated with recordkeeping for the required new monitoring.

The commenter (1301-NATBC) states that the November 2021 Proposal, as presented, does not adequately address the expenses necessitated by the Rule to be borne by operators. During Northern Arapaho’s January 24, 2022, consultation with the EPA regarding the proposed rule, the commenter notes that EPA representatives indicated that: (1) they possess and would provide additional information regarding estimated costs of bringing individual wells into compliance with the proposal regarding fugitive emissions; and (2) EPA will be issuing supporting statements regarding expenses associated with the anticipated record-keeping burden and implementation plan development. The commenter states that they look forward to disclosure of that information. The commenter concludes that EPA should account for and report on all such implementation-scale compliance costs.

Response I-4-20: The detailed information requested by the commenter is provided in the technical support documents. These include the TSD for the November 2021 proposal,<sup>11</sup> the TSD for the December 2022 supplemental proposal,<sup>12</sup> and the TSD for the final rule.<sup>13</sup> All three

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<sup>11</sup> November 2021 TSD.

<sup>12</sup> December 2022 TSD.

<sup>13</sup> Final Rule TSD.

of these TSDs, as well as Microsoft Excel workbooks that provide more details on the calculations, are available in the docket.

## Chapter 5. Control Devices

### 5.1 Flares

#### *5.1.1 Emergency Flares Applicability Clarification*

Comment: Commenter (0843-Environmental Integrity Project (EIP)) states that the November 2021 Proposal fails to define critical terms needed for implementation, including the terms that describe flare operating scenarios considered to be permissible and/or covered by the proposed rule. The commenter urges EPA to carefully define what constitutes an unforeseeable startup, shutdown, or malfunction (upset) versus foreseeable operating scenarios. In particular, the commenter contends that EPA must explain the difference between and define an “emergency” flare and a “process” flare (if “process flares” are allowed). The commenter requests that if EPA means to exclude emergency flares from the requirements generally applicable to flares, the rule should state so explicitly, as well as state precisely what constitutes emergency versus routine flaring. Otherwise, they recommend that EPA clarify that emergency flares are subject to the flaring requirements.

The commenter (0843-EIP) notes that in Texas, most flares are authorized to release only nominal, pilot flame, emissions, and some flares are authorized to release large amounts of pollution during “planned maintenance, startups, and shutdowns.” Texas has acknowledged that oil and gas operators, specifically, need additional guidance to comply with NSPS OOOOa given the state’s emission events rules.<sup>1</sup> However, despite efforts at guidance, the commenter notes that the Texas data clearly shows that operators claim and report “upsets” (defined in Texas as “emission events”) for all manner of weather-related, emergency/non-emergency, third-party-caused, and routine business practices. For example, operators have filed upset/emission event reports in Texas “to conduct maintenance,” when third parties (*i.e.*, gas processing plants) “shutdown to perform maintenance,” “since the gas could not be sold....,” “for planned maintenance,” and other routine or easily foreseeable events.<sup>2</sup>

The commenter (0843-EIP) contends that recent initial enforcement actions illustrate the need for EPA to clearly define flare operating scenarios covered by the November 2021 Proposal. Texas operators throughout the Permian Basin claim normal and routine events as upsets. For example, in one recent investigation, Texas regulators explained:

It has been determined by the TCEQ that emissions caused by routine downstream actions are not emission events and must be permitted. Downstream conditions which are reasonably routine activities should be anticipated and the upstream facility should consider these activities as part of their permitted emissions. Since many of the reported

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<sup>1</sup> See TCEQ, Oil and Gas Industry Emissions Events (EE) Workshop, (Nov. 5, 2020). Accessible at: <https://www.tceq.texas.gov/downloads/assistance/industry/oil-gas/og-emissions-events-presentation.pdf>.

<sup>2</sup> Submission Attachment B, TCEQ STEERS Incident Reports, Incident Tracking Numbers 334964, 335023, 337490, 338078, 344345 TCEQ Search Air Emission Event Reports (texas.gov).

events were caused by conditions downstream of this site and were reasonably routine, the emissions are considered to require a permit.<sup>3</sup>

See Attachment C of commenter's (0843-EIP) public submission, TCEQ Johnson Unit Compliance Investigation, Occidental Permian (June 22, 2021); see also Attachments D & E of commenter's public submission (two other recent TCEQ investigation reports for facilities in the Permian Basin).

The commenter (0843-EIP) adds that there is no definition or clarity for operators as to what constitutes "reasonably routine" and, therefore, the line between permitted activities and upsets remains blurred.

Response I-5-1: EPA disagrees that it is necessary to define startup, shutdown, and malfunction because the rule requires that owners and operators always operate each control device in compliance with the control device requirements when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to NSPS OOOOb and EG OOOOc.

### ***5.1.2 Support Increased Regulation of Flaring***

Comment: Commenter (0807-BP America, Inc. (BP)) supports EPA exploring ways to enhance regulatory oversight through standards that incorporate assurances to reduce flaring. The commenter welcomes the opportunity to provide additional comments on flares in the supplemental rulemaking.

Commenter (0770-Northern Plains Resource Council (NPRC)) believes that EPA has an obligation to strengthen its November 2021 Proposal and advance rules that leave no loopholes nor future opportunities for methane pollution from oil and gas infrastructure.

Commenter (0729-Energy Workforce & Technology Council (EWTC)) believes that the regulation of flaring is an additional component that will be paramount to the efforts of decreasing overall emissions. The commenter states that traditionally, flaring has been a means for producers and operators to combust uneconomic or unusable natural gas that is produced as part of the extraction process at the well site. The commenter notes that while the majority of harmful components in the field gas are neutralized through flaring, incomplete combustion by inefficient flares can result in significant quantities of methane emitted to the atmosphere, so called "methane slip."

Commenter (0828-Union of Concerned Scientists (UCS)) states that EPA must strengthen its position regarding routine flaring. The commenter asserts that the costs of routine flaring are staggering and despite operators flagrantly wasting saleable product, many of flaring's true costs are borne on the backs of the public in the form of health-harming and climate-forcing

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<sup>3</sup> See Attachment C, TCEQ Investigation Report, Customer: Occidental Permian Ltd., June 22, 2021  
See also Attachments D&E (two other recent TCEQ investigation reports for facilities in the Permian Basin; Docket online access restricted-copyrighted materials).

pollutants.<sup>4</sup> However, the commenter notes that the November 2021 Proposal continues to defer to the immediate interests of producers over the health and wellbeing of the public. The commenter states that EPA must eliminate its too permissive allowance for operators to fail to meet what should be a baseline requirement for production: planning and investing in sufficient gas offtakes.

Commenters (0444-Damascus Citizens for Sustainability (DCS), 0715-Dayenu Circle of Jewish Silicon Valley (DCJSV)) note that the rule does not regulate flaring, a large source of emissions. The commenter notes that New Mexico and Colorado regulate flaring, and they request that EPA follow their examples.

Response I-5-2: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices and sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal related to flaring of associated gas.<sup>5</sup> Also, see Chapter 17 of this Response to Comments document (Volume I) for more information related to flaring of associated gas.

Comment: Several commenters (0201-Sierra Club-Lone Star Chapter (Sierra Club-LSC), 0559-TX State Senator Eckhardt, 0941-350Silicon Valley, 1297-Texas State House) support federal regulation of flaring because they contend that several states fail to enforce regulation and because several state rules are insufficient.

Commenter (0201-Sierra Club-LSC) provides examples of Texas's inaction. The commenter notes that Railroad Commission of Texas (Texas RRC) through Rule 32 has specific rules on flaring and venting, but other than some modest improvements on reporting and data, has continued to allow oil producers to flare off large volumes of gas. While the Texas Commission on Environmental Quality (TCEQ) does have well established regimes on oil and gas air permitting, there is a confusing array of different kinds of permits depending on the size and location of oil and gas wells and associated equipment. Texas does not have specific standards on methane and has rejected suggestions to develop state standards. In leasing state lands, neither the General Land Office nor the university systems that benefit from leasing these lands have imposed specific standards on oil and gas producers. Indeed, state leadership – both the TCEQ and RRC – have opposed previous federal efforts to implement strong methane standards, often joining in lawsuits to prevent regulations designed to lower emissions.

Moreover, the commenter (0201-Sierra Club-LSC) contends that state legislature and the Governor have failed to take any action to reduce flaring, venting or fugitive emissions, other than through the creation of incentives like the Texas Emissions Reduction Plan. Indeed, in some cases, the legislature has stepped in and made it harder to increase regulation of oil and gas air emissions in Texas.

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<sup>4</sup> The proposed rule estimates product recovery—across all intervention measures—to be on the order of \$5.5 billion through 2035, or \$520 million each year (Fed. Reg. 63123).

<sup>5</sup> 87 FR 74779, 74780, and 74792 (December 6, 2022).



Commenters (0559-TX State Senator Eckhardt, 1297-Texas State House) report that in the last seven years, the Texas RRC has granted operators more than 27,000 permits to flare,<sup>6</sup> resulting in the burning of nearly 1 trillion cubic feet of natural gas.<sup>7</sup> In 2020, the Texas RRC granted about 4,500 exceptions to flaring regulations.<sup>8</sup> Commenter (0559-TX State Senator Eckhardt) states that according to ExxonMobil, their “experience in the Permian Basin demonstrates that zero routine flaring is within everyone’s reach.”<sup>9</sup> and the Texas Methane and Flaring Coalition “agrees we should strive to end routine flaring.”<sup>10</sup> The commenter reports that despite all of these benefits, methane leaks and flaring are common. The commenter states that industry needs clear guidance and nationally established minimum standards, instead of an unproductive (and sometimes counterproductive) piecemeal state approach.

Response I-5-3: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices and sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal related to flaring of associated gas.<sup>11</sup> Also, see Chapter 17 of this Response to Comments document (Volume I) for more information related to flaring of associated gas.

Comment: Commenter (0807-BP) is pleased that EPA is soliciting comment on operation of flares as flaring is a significant source of methane for their sector. The commenter provides details of their efforts to reduce and intention to eliminate flaring. In April 2021, the commenter announced their intention to eliminate routine flaring in their U.S. onshore operations by 2025 or sooner. To achieve this goal, all newly constructed well sites are tied into gas delivery pipelines from start-up, and new wells are not brought online unless the wells have access to a gas pipeline. The commenter reports that it is also building centralized production facilities and converting legacy wells from high pressure systems to low pressure gas gathering systems to tie in more of their existing production into centralized facilities. Notably, since taking operational control over BHP’s oil and gas assets in Texas’s Permian Basin in 2019, the commenter reports that they have reduced flaring intensity in the basin from 16 percent in the fourth quarter of 2019 to less than 1 percent today.

The commenter (0807-BP) provides that actions to address the efficiency and operations of flares include installing air assist to improve the flare combustion efficiency and thermocouple sensors on all flare stacks to notify operations teams of unlit flares. They add that all flares have auto-ignitors to attempt to remotely reignite flames that have extinguished.

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<sup>6</sup> Texas Tribune, “Pipeline giant sues Railroad Commission, alleging lax oversight of natural gas flaring,” Dec 3, 2019, <https://www.texastribune.org/2019/12/03/railroad-commission-sued-lax-oversight-natural-gasflaring/>.

<sup>7</sup> EDF, “A zero flaring policy is long overdue, and investors can help make it reality,” May 27, 2020, <http://blogs.edf.org/energyexchange/2020/05/27/a-zero-flaring-policy-is-long-overdueand-investors-can-help-make-it-reality/>.

<sup>8</sup> Texas Tribune, “As world leaders seek to rein in methane, Texas’ oil and gas industry pressured to cut emissions,” Nov 2, 2021, <https://www.texastribune.org/2021/11/02/epa-methane-emissions-oil-gas/>.

<sup>9</sup> EnergyFactor by ExxonMobil, “Reducing Natural Gas Flaring,” accessed Jul 29, 2020, available at <https://energyfactor.exxonmobil.com/perspectives/reducing-natural-gas-flaring/>.

<sup>10</sup> Texas Methane & Flaring Coalition, “Flaring Recommendations and Best Practices,” accessed Jun 16, 2020, <https://texasmethaneandflaringcoalition.org/wp-content/uploads/2020/06/6-16-20-TMFC-FlaringRecommendations-Best-Practices-Report.pdf>.

<sup>11</sup> 87 FR 74779, 74780, and 74792 (December 6, 2022).

Another commenter (0729-EWTC) states that flaring alternatives and on-site innovations that have emerged from within the energy sector have already addressed concerns regarding traditional flaring and companies are developing new ways to reduce and decrease flaring efforts altogether. The commenter notes that chief among these efforts has been the repurposing of collected field gas to power wellsite operations. The commenter states that gases that would have traditionally been flared are now being used on-site in a closed-loop process with minimal methane emissions.

Response I-5-4: We acknowledge the information provided by the commenters.

Comment: Commenter (0757-Private Equity Stakeholder Project (PESP)) notes that private equity-backed operators have a track record of releasing problematic levels of methane into the atmosphere. In EDF's analysis of 2018 flaring data, private equity firm NGP Capital's Steward Energy II<sup>12</sup> was the 60<sup>th</sup> largest Permian natural gas producer, but it was the fourth largest flarer by volume. The commenter reports that Steward flared more natural gas than XTO Energy, despite XTO having produced more than 10 times the amount of natural gas as Steward. The commenter adds that Steward was found to flare approximately 65 percent of all the gas it produces – meaning that about two-thirds of the natural gas Steward extracts from the ground is flared – further damaging the environment and nearby communities.<sup>13</sup>

Response I-5-5: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices and sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal related to flaring of associated gas.<sup>14</sup> Also, see Chapter 17 of this Response to Comments document (Volume I) for more information related to flaring of associated gas.

### ***5.1.3 Oppose Increased Regulation of Flaring***

Comment: Commenters (0808-American Petroleum Institute (API), 0831-American Exploration and Production Council (AXPC)) state that the refining sector is vastly different than oil and gas well sites, centralized production facilities, and compressor stations. The commenters state that the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir.

Commenter (0808-API) reports that oil and natural gas are located thousands of feet below the surface and must flow in two or three phases to the surface. The mixture is then separated in the two or three-phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system.

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<sup>12</sup> Steward Energy, "History," January 6, 2022, <https://stewardenergy.net/about-steward/>.

<sup>13</sup> Colin Leyden, "New Permian Data Show How Worst Offenders Prevent Progress on Flaring," Texas Clean Air Matters - EDF, August 14, 2019, <https://blogs.edf.org/texascleanairmatters/2019/08/14/new-permian-data-show-how-worst-offenders-preventprogress-on-flaring/>.

<sup>14</sup> 87 FR 74779, 74780, and 74792 (December 6, 2022).

The commenter (0808-API) states that as production declines in a gas well, management of wellbore liquids can mean that flow to the control device can vary from essentially zero to high flow rates and quickly back to zero rapidly and often. The commenter explains that this highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible in these conditions.

The commenter (0808-API) believes it is not appropriate nor cost effective to apply refinery-oriented requirements to upstream flares. Costs for Subpart CC controls at refineries are \$1 million plus, with major ongoing costs. Costs would be much greater at upstream facilities without the necessary utilities and instrumentation resources. The commenter contends that it is not clear that there is instrumentation available that would work reliably under the varying operating conditions. Additionally, the commenter notes that adding natural gas to a flare to control the BTU content incurs capital costs as well as ongoing costs and generates considerable greenhouse gases that would not otherwise be emitted.

The commenter (0808-API) notes that many states have moved to include some type of flare monitoring requirement within their local regulations or permitting processes. For example, Texas<sup>15</sup> requires that flares meet 40 CFR 60.18 requirements for minimum heating value and maximum tip velocity and have a continuous pilot flame (monitored by thermocouple or equivalent device) or an automatic ignition system.

Response I-5-6: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to requirements for combustion control devices.<sup>16</sup> See additional responses related to comments on combustion control devices in Volume II, Chapter 17.

Comment: Commenter (0585-Kentucky Oil and Gas Association (KOGA)) notes that many environmental groups advocating for EPA to eliminate oil and gas companies' ability to burn gas at well sites through a flare are the same environmental organizations that oppose new pipelines to move gas into markets. The commenter states that without the ability to transport gas to market via pipeline, burning the gas with a flare is one of the last options available.

Commenter (0585-KOGA) requests that EPA allow small volumes of gas to be flared, without incurring the expense of delivering a flare that has a 95 percent certification to the wellsite because that small volume of gas that is burned through the low-cost maintenance event should not be burdened with the significant expense of delivering a flare to the wellsite. The commenter contends that a typical maintenance cost for many of our operators is \$3,500 to \$5,000 to service an oil or gas well. The commenter reports that the additional cost to deliver and set up a 95 percent certified flare system is estimated to be an additional \$1,000 to \$2,000 per maintenance event. This requirement will add 30 percent to 40 percent to the cost of servicing the well with little additional environmental benefit.

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<sup>15</sup> Texas Commission on Environmental Quality, Control Device Requirements Charts for Oil and Gas Handling and Production Facilities (February 2012).

<https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf>.

<sup>16</sup> 87 FR 74792 (December 6, 2022).

Response I-5-7: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices and sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal related to flaring of associated gas.<sup>17</sup> Also, see Chapter 17 of this Response to Comments document (Volume I) for more information related to flaring of associated gas.

Comment: Commenter (0817-GPA Midstream Association (GPA)) states that “additional measures” for flares are not required, cost efficient, or appropriate for control device performance. The commenter believes that the manufacturer’s design guarantee should be allowed for compliance purposes to ensure good combustion. The commenter provides that, in assessing whether additional measures add value in the midstream sector, it is important to consider that flaring at midstream facilities is very different than those at large industrial facilities, such as chemical plants or refineries, and provide a basis for EPA to distinguish regulation among flares in different sectors. Flares for gathering and boosting compressors and at natural gas processing plants do not have streams with the types of complex gases found in chemical plants and oil refineries. The commenter notes that there is no significant concentration of inert gases in the flare systems and no ethylene or propylene to increase combustion zone net heating values. Moreover, the commenter contends that midstream operations have substantially lower flow rates than chemical plants or refineries. They add that there is simply a lower volume of continuous waste streams. The commenter states that this is especially true at compressor stations, where flares and combustors are used to control specific equipment, not multiple sets of process units.

Moreover, the commenter (0817-GPA) informs that the accurate flow measurement for low flow streams is costly. The commenter estimates that these flow meters are approximately \$100,000.<sup>18</sup> Requiring the industry to obtain these flow meters for each site within a short compliance timeframe would only increase costs. Adding low flow meters would not be cost effective given the low waste stream flow and the number of flow meters<sup>19</sup> that would need to be installed. Thermocouples (or equivalent devices) currently ensure that a pilot is lit continuously and an alarm sounds when the pilot is lost. The commenter believes that is sufficient to track and verify operation. If EPA were to consider further verification, the commenter recommends that EPA consider using minimum flows or hours (*e.g.*, X volume per year) as monitoring threshold while excluding temporary flares. Moreover, commenter (0817-GPA) adds that, particularly in the case of the midstream sector, compressor stations are often remotely located, numerous, and not manned continuously and would, therefore, require expensive equipment and/or extensive and

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<sup>17</sup> 87 FR 74779, 74780, and 74792 (December 6, 2022).

<sup>18</sup> EPA expects costs of ultrasonic meter installation to be \$50,000. See EPA, Replace Bi-Directional Orifice Metering with Ultrasonic Meters (available at [https://urldefense.com/v3/\\_\\_https://www.epa.gov/sites/default/files/2016-06/documents/replacebidirectional.pdf\\_\\_;!!Omh0IfYXnA!hIdkI7nB\\_2pNpsUacEKDs4Uy5JCX7ksNZfTcw7\\_hvr56P8eeLVOJLU-kfuR925nG\\$](https://urldefense.com/v3/__https://www.epa.gov/sites/default/files/2016-06/documents/replacebidirectional.pdf__;!!Omh0IfYXnA!hIdkI7nB_2pNpsUacEKDs4Uy5JCX7ksNZfTcw7_hvr56P8eeLVOJLU-kfuR925nG$)) (*last accessed* January 14, 2022).

<sup>19</sup> EPA estimates 1484 compressor stations in the justification for this rule. Proposed Rule TSD, EPA-HQ-OAR2021-0317-0166. Assuming 1 flare for a dehydrator, 1 flare for tanks, and 1 flare for the facility blowdowns, this would total 4,452 flow meters for gathering and boosting alone. There were 462 gas plants reported under GHGRP. See EPA, GHGRP Data Sets (available at <https://www.epa.gov/ghgreporting/data-sets>). (*last accessed* January 14, 2022). Assuming 2 flares per facility for equipment blowdowns and 1 flare for loading for each facility, this would be another 1,386 flares in the processing segment.

unrealistic operational changes to conduct continuous monitoring with no expected real benefit. Maintenance would be a significant burden for the midstream industry. Unlike with manned facilities with on-site maintenance staff and fabrication shops, it may take days before staff could get to an unmanned site to make repairs. According to the commenter, this could mean that a site may have to shut down until repairs are completed or be in violation.

Response I-5-8: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>20</sup> Additional responses on the final requirements for monitoring flow to combustion control devices are located in Volume II, Chapter 17.

Comment: Commenter (0911-North Dakota Petroleum Council (NDPC)) states that if EPA requires flares that meet 40 CFR 60.18 with no exceptions, additional gas needs to be brought onsite to make up the minimum flowrate, likely increasing greenhouse gas emissions. The commenter notes that North Dakota, as well as some other states, allow for combustion devices other than those that meet 40 CFR 60.18. Some wells and storage tanks do not produce enough gas to support the minimum flow rate as specified in 40 CFR 60.18. In these cases, the best practice is to use a flare that has a lower destruction efficiency with an auto-ignitor that sparks every few seconds.

Response I-5-9: EPA notes that it is not mandating the use of flares in NSPS OOOOb or EG OOOOc. Flares are a control option for various affected facilities within the rule, but other control options such as carbon beds or condensers can also be used in low flow situations where a flare may not be viable, as long as the control device is capable of achieving the level of control specified in the rule. Pressure valves can also be used to prevent flow to the flare until there is enough flow to ensure adequate combustion efficiency.

#### ***5.1.4 Support Banning of Flaring/Non-Emergency Flaring***

Comment: Commenters (0357-National Parks Conservation Association (NPCA), 0435-Wespath Benefits and Investments, 0437-New York Office of the State Comptroller (NYOSC), 0578-Grand Canyon Trust (GCT), 0589-NEI Investments (NEI), 0720-Miller/Howard Investments, 0723-Ceres, 0724-Boston Trust Walden, 0728-Calvert Research and Management, 0734-American Thoracic Society (ATS), 0757-PESP, 0770-NPRC, 0783-CA Assemblymember Bloom *et al.*, 0788-350 Seattle, 0795-American Lung Association *et al.* (ALN *et al.*), 0796-Asthma and Allergy Foundation of America – Michigan Chapter *et al.* (AAFA-MI *et al.*), 0812-Ohio Farmers Union *et al.* (OFU *et al.*), 0837-Clean Water Action *et al.* (CWA *et al.*), 0840-Navajo Nation, Counselor Chapter House, 0841-Red Mesa Chapter Governance-Navajo Nation (RMCG-Navajo), 0920-WE ACT for Environmental Justice (WAEJ), 0927-Interfaith Center on Corporate Responsibility (ICCR), 0937-Fort Berthold Protectors of Water and Earth Rights (Fort Berthold POWER), 0941-350Silicon Valley, 0942-CleanEarth4Kids, 0947-Alliance of Nurses for Healthy Environments-Colorado *et al.* (ANHE-CO *et al.*), 0948-Quirk, 0949-Liveable Arlington, 0958-Climate Code Blue (CCB), 1270- League of Women Voters of the United States (LWVUS), 1282-Earthworks, 1297-Lopez *et al.*, 1302-Wyoming Outdoor Council (WYOC) and the Powder River Basin Resource Council (PRBRC), 1330-Catskill Mountainkeeper, 1338-Lexington Climate Action Network, 1339-Waterway Advocates, 1372-Generate Capital PBC,

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<sup>20</sup> 87 FR 74792 (December 6, 2022).

1389-VERIS Wealth Partners, 1423-Beyer *et al.*, 1434-Heinrich *et al.*) urge EPA to prohibit the practice of routine flaring. Many of these commenters express concern regarding flaring emissions of VOCs, carbon monoxide, sulfur dioxide, polycyclic aromatic hydrocarbons, nitrogen oxides, black carbon, and other pollutants which they state have significant adverse human health impacts and flaring carbon dioxide emissions' contribution to climate change. Representative specific comments are provided in the following paragraphs.

Commenter (0783-CA Assemblymember Bloom *et al.*) states that many California communities also suffer from the impacts of flaring. According to the commenter, news reports of plumes of black smoke and related health threats are common in Richmond<sup>21</sup> and Los Angeles<sup>22</sup> because of this practice of burning gas as a waste product, instead of capturing and selling it as part of oil extraction. The commenter states that the consequence is the release of toxic pollutants that contribute to public health crises and climate change. According to a joint USC-UCLA study, living within "3 miles of flaring is associated with increased risk of preterm birth"<sup>23</sup> and the practice is also linked to higher rates of asthma, as well as negative cardiopulmonary and cardiovascular impacts. As one of the authors of the study stated, "Our findings show that flaring is an environmental justice issue... We found that a significant number of Black, Indigenous and Latinx people live near flaring. High rates of poverty and other barriers to health in rural areas — such as a lack of access to health care — could worsen the health effects of flaring-related exposures."<sup>24</sup> The commenter asserts that, given that leading operators and some states have successfully ended routine flaring, there is no justifiable reason to continue allowing the practice and EPA should use this regulatory process to end it in non-emergency situations.

Commenters (0942-CleanEarth4Kids, 0937-Fort Berthold POWER, 0947-ANHE-CO *et al.*, 1339-Waterway Advocates) suggest ending all routine flaring along with setting monitoring, enforcement, and fines to ensure unlit flares are not venting methane.

Commenter (0357-NPCA) requests that the supplemental proposal eliminate the wasteful and dangerous practice of routine flaring at oil and gas facilities, except in emergency situations. The commenter notes that routine flaring burns natural gas as a waste product, emitting a host of climate and health-harming pollutants. They add that flaring also wastes money, companies operating on federal and tribal lands waste approximately \$330 million each year through leaks, venting and flaring.

Commenter (0920-WAEJ) urges EPA to end venting and routine flaring and ensure there is proper enforcement to guarantee unlit flares are not venting methane. The commenter supports EPA's intention to regulate this significant source of methane under the CAA for the first time because doing so will prevent fugitive methane emissions and dangerous co-pollutants such as polycyclic aromatic hydrocarbons, carbon monoxide, nitrogen oxides, heavy metals, and black

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<sup>21</sup> See for instance, multiple stories over just a few months in 2021, such as <https://www.youtube.com/watch?v=JgK7O4UgoEI>, <https://abc7news.com/richmond-chevron-flaring-black-smoke-refinery/10943396/>, <https://richmondconfidential.org/2021/10/29/richmond-chevron-refinery-flaring/>.

<sup>22</sup> <https://www.latimes.com/california/story/2021-08-09/flares-chevron-refinery-light-up-the-sky-el-segundo>.

<sup>23</sup> Lara J Cushing et al 2021. Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US. *Environ. Res. Lett.* 16 034032. <https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4>.

<sup>24</sup> <https://news.usc.edu/183286/americans-oil-gas-flaring-health-risks-usc-research/>.

carbon. The commenter notes that these pollutants lead to adverse health impacts that unduly burden environmental justice communities.

The commenter (0920-WAEJ) urges EPA to reconsider their November 2021 Proposal on how to utilize gas that would otherwise be vented as it could lead to added environmental and health burdens for frontline communities. The commenter recommends weighing the benefits of requiring producers to capture gas for on-site power or other useful purposes or routing it to a flare or control devices with the potential climate and environmental justice impacts of these mitigation measures.

Commenter (0958-CCB) recommends that EPA ban routine flaring at all oil and gas sites. The commenter notes that in addition to contributing to methane emissions, flaring exposes worker and surrounding communities to VOCs, polycyclic aromatic hydrocarbons, carbon monoxide, toxic heavy metals, soot, benzene and formaldehyde, posing serious health harms.

Commenter (0437-NYOSC) notes that in prior outreach to EPA on this matter, the New York State Common Retirement Fund and other investors have called for the elimination of venting and minimization of flaring. The commenter believes that the proposed rule only partially meets expectations for a robust rule that fully addresses methane emissions. The commenter urges EPA to end the practice of routine natural gas flaring. Natural gas flaring produces GHG emissions and waste a potentially saleable product which could otherwise be captured. The commenter notes that a growing number of companies have voluntarily committed to ending routine flaring and recommends that EPA require an end to this harmful and wasteful practice.<sup>25</sup>

Commenter (0435-Wespath Benefits and Investments) urges the EPA to set a near-term end date for operators to cease routine flaring of natural gas at oil and gas facilities, as states like Colorado and New Mexico have already done.

Commenter (0757-PESP, 1282-Earthworks) believes that EPA's November 2021 Proposal does not go far enough to address pollution from flaring. The commenters assert that EPA's final rule must prohibit the practice of routine flaring at oil and gas sites. The commenters state that when companies rush to extract oil, some forgo investments necessary to capture and sell gas and instead burn it as a waste product, emitting a host of climate and health-harming pollutants. Flaring is a wasteful practice and a large source of methane, carbon dioxide, nitrogen oxides, VOCs, and HAPs. Capturing natural gas that would otherwise be vented or flared reduces significant amounts of pollution and even generates revenue for operators. The commenters assert that EPA must eliminate flaring except in emergency situations.

Commenter (0578-GCT, 0812-OFU *et al.*, 0948-Quirk, 1423-Beyer *et al.*, 1434-Heinrich *et al.*) urges EPA to adopt final federal rules to cut methane by prohibiting routine venting and flaring, following the example of Alaska, Colorado, and New Mexico. Commenters (0723-Ceres, 0788-350Seattle, 0841-RMCG-Navajo, 0937-Fort Berthold POWER, 0941-350Silicon Valley, 1330-Catskill Mountainkeeper) recommend that EPA end routine flaring at oil and gas facilities, as

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<sup>25</sup> Hampton, Liz, "U.S. Shale Producer APA ends Flaring, Captures More Gas as Prices Soar," Reuters, October 11, 2021. Available at: <https://www.reuters.com/business/energy/us-shale-producer-apa-ends-flaring-captures-more-gas-prices-soar-2021-10-11/>.

states like Colorado and New Mexico have done. Commenter (0723-Ceres) states that EPA must ensure that flaring only occurs in emergency situations. The commenter notes that capturing gas that would otherwise be flared or vented would generate revenue for operators. Commenter (0841-RMCG-Navajo) reports that flares commonly malfunction and spew methane directly into the atmosphere.

Similarly, commenter (1302-WYOC/PRBRC) recommends that in future rules EPA ban routine flaring at oil and gas sites, following the lead of states like Colorado and New Mexico. The commenter asserts that when companies develop oil and gas resources, they often forgo investments necessary to capture and sell gas and instead vent or flare it as a waste product. Companies may also choose to flare gas when prices are low, as it may be more economically expedient to simply flare the gas than to pay for transport. The commenter states that gas flares emit a host of climate and health-harming pollutants, and many have been found to malfunction or fail entirely, spewing methane directly into the atmosphere. The commenter notes that the practice of routine flaring represents a significant loss of revenue as well as operators are not required to pay royalties on the valuable natural resource, meaning that states and land managers lose out on important revenues. According to the commenter, this is particularly damaging for Wyoming, which relies heavily on fossil fuel royalties to fund the budget. The commenter recognizes that there are emergency situations where flaring is needed, however, oil and gas operators should not be allowed to flare simply when it is economically convenient for them.

Commenter (0941-350 Silicon Valley) asserts that EPA must ban routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already, and as the European Union recently proposed to do. The commenter states that the wasteful and dangerous practice of routine gas flaring in the industry must be halted. Frequently flaring is incomplete, resulting in substantial amounts of methane emissions, sometimes in combination with gases having even greater global warming potentials, such as black carbon and nitrous oxide, and frequently with harmful amounts of criteria pollutants such as benzene and SO<sub>2</sub>. Even when routine flaring combustion is complete it is still undesirable because it is a significant source of carbon dioxide emissions.

The commenter states that banning routine flaring is crucial for eliminating the methane emissions that often accompany excessive flaring.<sup>26</sup>

Commenter (1270-LWVUS) recommends that EPA prohibit all non-emergency flaring. The commenter states that there is an urgent need for detailed consideration of problems related to the extensive use of flaring, both at well sites and downstream. The commenter explains that while flaring is preferable to emissions of methane, it is currently overused, and the flaring process is inadequately controlled. The commenter notes that this will likely necessitate financial support for a significant portion of smaller oil and gas producers.

Commenter (1270-LWVUS) provides the following information on flaring. Drilling, extraction, storage and processing of gas and oil all may be accompanied by bursts of natural gas being released to the air. Such venting operations result in large emissions of methane. Flaring these vented streams can reduce methane emissions but is not a generally acceptable approach. At its

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<sup>26</sup> Permian Methane Analysis Project, EDF.



best it wastes a valuable resource, generates CO<sub>2</sub> without producing anything of value, and generates soot, which contains large amounts of polyaromatic hydrocarbons that are toxic, carcinogenic and also potent global warming agents.

The commenter (1270-LWVUS) explains that flares operating at optimum efficiency should completely burn more than 99 percent of natural gas emissions according to a report from the International Energy Agency (IEA).<sup>27</sup> However, as wells start to operate at less than maximum flow, the flare performance is more strongly affected by environmental conditions such as windspeed. With very high winds the flares may even be blown out. Failure to maintain the flares in proper working condition can also decrease combustion levels and contribute to the likelihood of the flame being extinguished.

The commenter (1270-LWVUS) adds that the IEA study estimates the average worldwide efficiency for flares to be about 92 percent. Most flaring in the U.S. occurs at oil and gas basins that do not have options to export natural gas. According to the commenter, it would be better to capture the gas and transport it to markets, use it on site to supply heat or electrical generation, or convert it to products such as methane or LNG that can be shipped out in trucks. For large scale producers of gas and oil, these efforts to monetize this now-wasted gas should result in a significant net benefit. The commenter notes that some major companies have, in fact, begun to take such steps on a voluntary basis.<sup>28</sup>

For small companies, the commenter (1270-LWVUS) informs that the monetization of the lost gas will not offset the cost of implementing appropriate ways to market it. The commenter suggests that if these companies are required to pay for the methane they are emitting, it seems likely they will turn to flaring. At smaller companies, which often have older equipment and lower throughput to the flare, the commenter suggests it seems likely that the problems associated with all flaring equipment will be exacerbated.

The commenter (1270-LWVUS) states that the IEA has suggested that all but emergency flaring be prohibited at all wellsite facilities (as well as at the downstream facilities that will be covered in future regulations). They suggest that funding be supplied as appropriate to help smaller facilities make the necessary investments. Unless all non-emergency flaring is ended worldwide by 2030, the IEA says, the U.S. will be unable to meet the goals laid out in its Net Zero by 2050 road map. The commenter notes that it seems likely that many countries will fail to meet this goal, but the U.S. can and should meet it.

Commenter (0578-GCT) states that flares are prone to malfunctioning, or being left unlit, and as a result using flaring to dispose of associated gas produces significant flaring emissions. The commenter reports that a recent study by EDF estimates 75,000 metric tons of methane emissions were released from properly functioning flares, 30,000 metric tons from malfunctioning flares, and 200,000 metric tons from unlit flares in the Permian Basin.<sup>29</sup> The commenter informs that the study is limited in that it was only conducted in the Permian Basin. But the commenter asserts that, given the equipment used in the Permian Basin is not unique

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<sup>27</sup> <https://www.iea.org/reports/flaring-emissions>.

<sup>28</sup> <https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/31/fact-sheet-the-american-jobs-plan/>.

<sup>29</sup> EDF. Flaring Aerial Survey Results. Available at: <https://www.permianmap.org/flaringemissions/>.

across the oil and gas industry and oil and gas operations are found across the U.S., including the Colorado Plateau, there is grounds to assume that hundreds of thousands of metric tons of methane are likely emitted on the Colorado Plateau and across other areas of the U.S. each year without knowledge of surrounding communities.

The commenter (0578-GCT) notes that EPA estimates that functioning flares have 98 percent flaring efficiency rate based on a study conducted by EDF,<sup>30</sup> but the commenter states that the EDF's study found that flare malfunctions ranged from 3.3 percent to 11.5 percent at a random survey of routine flaring sites in the Permian Basin.<sup>31</sup> The study also found that 5 percent of flares were not fully lit and were failing to properly combust methane, and an additional 5 percent were unlit and directly venting methane.<sup>32</sup> Nearly 57 percent of these flares had multiple malfunctions.<sup>33</sup> The study goes on to state that "At this rate, flaring can now be considered one of the largest sources of methane emissions in the Permian Basin."<sup>34</sup>

Commenter (1267-CA AG *et al.*) contends that the EPA has underestimated HAP emissions from the oil and natural gas sector by relying on the National Emissions Inventory (NEI) to estimate emissions for rulemakings generally.<sup>35</sup> The 2017 Emission Inventory is based on emissions data reported to EPA by state and local agencies. However, the commenter suggests that this emissions data is often underreported for various reasons. For example, they explain that emissions from flares are commonly reported based on an assumption that flares operate at 98 percent destruction efficiency. The commenter explains that this means that operators reporting emissions from flares assume that 98 percent of the VOCs, methane, and HAPs being routed to the flare are combusted and converted into carbon dioxide. However, the commenter states that, in many instances, flares are operating at much lower destruction efficiencies or are unlit and are not operating at all. The commenter reports that seven random studies of routine flaring oil and natural gas sites found flare malfunctions ranged from 3.3 percent to 11.5 percent.<sup>36</sup> When expanded to all wells—the sites including lower-production, "marginal wells" – flare malfunctions jumped from 29 percent to 36 percent.<sup>37</sup> The commenter adds that a repeat study covering 200 square kilometers found that many malfunctioning flares failed more than once during a week; about one quarter of malfunctioning flares had problems on all three days of the study and over half of malfunctioning flares had problems on two days of the study.<sup>38</sup> In those situations, assuming a 98 percent destruction efficiency underestimates the actual emissions. The

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<sup>30</sup> Id.

<sup>31</sup> EDF. Permian Methane Analysis Project. February 2021. Available at: <https://data.permianmap.org/pages/flaring>.

<sup>32</sup> EDF. Through Turbulent Year, EDF Data Show Permian Oil and Gas Operators Consistently Failed to Keep Flares Lit. February 2021. Available at: <https://www.edf.org/media/through-turbulentyear-edf-data-show-permian-oil-and-gas-operators-consistently-failed-keep>.

<sup>33</sup> EDF. Fact Sheet. Permian oil and gas flaring emissions. Available at: [https://www.dropbox.com/sh/36peepzuja9zyuv/AAAFWrsqM7x6-7C8Ub7oglnAa?dl=0&preview=Permian\\_Flaring\\_Infographic\\_EDF.jpg](https://www.dropbox.com/sh/36peepzuja9zyuv/AAAFWrsqM7x6-7C8Ub7oglnAa?dl=0&preview=Permian_Flaring_Infographic_EDF.jpg).

<sup>34</sup> EDF. Flaring Aerial Survey Results. Available at: <https://www.permianmap.org/flaringemissions/>.

<sup>35</sup> For this rulemaking, EPA's risk assessment is based on the 2017 National Emissions Inventory (2017 NEI). RIA, at 4-25 ("We used the most recent National Emissions Inventory (NEI) data from 2017, which indicates nationwide emissions of approximately 110,000 tons of HAP for that year from oil and natural gas sources.")

<sup>36</sup> Att. 22, Environmental Defense Fund, Methodology for EDF's Permian Methane Analysis Project (Permian Map), p. 7, Table 1, p. 9, Table 5 (Nov. 17, 2021).

<sup>37</sup> Id. at 9.

<sup>38</sup> Id. at 8.

commenter states that a reduced destruction efficiency from 98 percent to 97 percent results in a 50 percent increase in emissions. A reduced destruction efficiency from 98 percent to 90 percent results in a 500 percent increase in emissions. The commenter adds that, if the flare is completely unlit, the resulting increase in emissions is 5000 percent. Based on the prevalence of malfunction and unlit flares, the commenter reports that the study concludes that actual emissions from flares are 3.5 times higher than reported.<sup>39</sup>

Commenter (0795-ALN *et al.*) provides that a ban on flaring is feasible and viable. The commenter notes that flaring of associated gas is a widely used practice for disposing of methane that comes to the surface where infrastructure is not in place to capture and transport it, resulting in the gas being burned off as waste. The commenter states that the practice is particularly common at oil wells, which may not bother to build infrastructure to capture gas. The commenter notes that the boom in domestic oil production enabled by fracking caused natural gas flaring to proliferate; in the Eagle Ford Shale region of south Texas, for example, from 2012 to 2016, 82 percent of flares were linked to oil wells, and nine out of ten were fracking wells.<sup>40</sup>

The commenter (0795-ALN *et al.*) notes that gas flaring contributes to climate change. A 2017 study of emissions from gas flares in North Dakota found that incomplete combustion from flaring was responsible for 20 percent of the total emissions of methane and ethane from the Bakken shale fields.<sup>41</sup> (Ethane is a very short-lived greenhouse gas, staying in the atmosphere only a matter of months.) The commenter asserts that these emissions are a significant problem, given that a 2020 study ranked the U.S. as one of the world's top nations for flaring.<sup>42</sup> The commenter states that while gas flaring across major U.S. oil basins dipped to a multi-year low during 2020 perhaps as a result of the Covid-19 pandemic,<sup>43</sup> it may be expected to pick up as the industry rebounds.

Besides contributing to climate change, the commenter (0795-ALN *et al.*) asserts that flaring also generates pollution that can have direct effects on the health of those working in or living near oil and gas operations. The commenter reports that air pollutants from flaring operations include VOCs, polycyclic aromatic hydrocarbons, carbon monoxide, toxic heavy metals and soot and include several carcinogens, notably benzene and formaldehyde. They add that a study of flaring in the Eagle Ford Shale showed flaring to be the dominant source of exposure to nitrogen oxide air pollutants in an otherwise rural area, thus creating respiratory health risks.

The commenter (0795-ALN *et al.*) reports other health impacts associated with gas flaring include greater risk of preterm birth and problems associated with sleep disruption. A 2020 study

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<sup>39</sup> Id. at 10.

<sup>40</sup> Franklin, M., Chau, K., Cushing, L. J., & Johnston, J. E. (2019). Characterizing flaring from unconventional oil and gas operations in south Texas using satellite observations. *Environmental Science & Technology*, 53(4), 2220-2228. doi: 10.1021/acs.est.8b05355.

<sup>41</sup> Gvakharia, A., Kort, E. A., Brandt, A., Peischl, J., Ryerson, T. B., Schwarz, J. P., . . . Sweeney, C. (2017). Methane, black carbon, and ethane emissions from natural gas flares in the Bakken Shale, North Dakota. *Environmental Science & Technology*, 51(9), 5317-5325. doi: 10.1021/acs.est.6b05183.

<sup>42</sup> Roest, G. S., & Schade, G. W. (2020). Air quality measurements in the western Eagle Ford Shale. *Elementa Science of the Anthropocene*, 8(1), 18. doi: <http://doi.org/10.1525/elementa.414>.

<sup>43</sup> Rystad Energy. (December 2020) Permian, Bakken gas flaring falls to multi-year lows, satellite data shows. <https://www.rystadenergy.com/newsevents/news/newsletters/UsArchive/shale-newsletter-december-2020/>.

of pregnant women living in the Eagle Ford Shale area of Texas found that exposure to oil and gas flaring was associated with a 50 percent increase in the risk of preterm birth.<sup>44</sup> Preterm birth is a leading contributor in the United States to infant death. Gas flaring, along with the intense artificial lighting used during round the-clock drilling and fracking operations, contributes to increased light pollution in rural areas. A 2021 study found that residents exposed to light pollution from oil and gas operations experienced increased levels of insufficient sleep.<sup>45</sup> Light pollution has long been linked to disruptions in melatonin levels and circadian rhythm, associated with depression, sleeping disorders, metabolic disease and cancer.<sup>46</sup>

However, the commenter (0795-ALN *et al.*) states that the experience of three oil- and gas-producing states indicates that the industry can drastically curtail flaring. The Alaska Oil and Gas Conservation Act prohibits waste of oil and natural gas, including the burning of from an oil or gas well, unless authorized by the Alaska Oil and Gas Conservation Commission or in the case of emergency or system testing.<sup>47</sup> Colorado adopted a ban on routine flaring of gas in November 2020, authorizing only a limited option to flare under special conditions, with the approval of the Colorado Oil and Gas Conservation Commission and not for longer than 24 hours.<sup>48</sup> And just months later, in March 2021, the New Mexico Oil Conservation Commission finalized rules to eliminate venting and flaring at new and existing wells by April 2022<sup>49</sup>.

Commenter (0589-NEI) states that eliminating the practice of routine flaring is a low hanging fruit that has significant potential to reduce emissions. The commenter notes that leading companies have already committed to ending the practice of routine flaring (*e.g.*, Apache, EOG and others) and several states and competing jurisdictions (*e.g.*, Alberta) are working towards the same goal. The commenter adds that the World Bank's Zero Routine Flaring by 2030 initiative, and the support it has from industry, shows the appetite this measure already has in the marketplace.

Commenter (1423-Beyer *et al.*) refers to EPA's reporting that flaring frequently occurs in routine, nonemergency situations or is used to bypass pollution control equipment, producing unacceptably high releases of sulfur dioxide and other pollutants including uncombusted

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<sup>44</sup> Cushing, L. J., Vavra-Musser, K., Chau, K., Franklin, M., & Johnston, J. E. (2020). Flaring from unconventional oil and gas development and birth outcomes in the Eagle Ford Shale in South Texas. *Environmental Health Perspectives*, 128(7). doi: 10.1289/EHP6394.

<sup>45</sup> Andrew Boslett, Elaine Hill, and Lujia Zhang, "Rural Light Pollution from Shale Gas Development and Associated Sleep and Subjective Well-Being," *Resource and Energy Economics* 64 (2021), <https://doi.org/10.1016/j.reseneeco.2021.101220>.

<sup>46</sup> Chepesiuk, R. Missing the Dark: Health Effects of Light Pollution. Jan. 2009. *Environ Health Perspect.* 117(1): A20–A27. doi: 10.1289/ehp.117-a20. <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2627884/>.

<sup>47</sup> U.S. DOE Office of Fossil Energy. 2019. Alaska Natural Gas Flaring and Venting Regulations. <https://www.energy.gov/sites/prod/files/2019/08/f66/Alaska.pdf>.

<sup>48</sup> EUCI. Energize Weekly. December 2, 2020. <https://www.euci.com/colorado-adopts-sweeping-oil-and-gas-rulesbanning-flaring-creating-a-2000-foot-setback/>.

<sup>49</sup> S&P Global Platts. March 26, 2021. New Mexico regulator puts in place rule requiring operators to eliminate gas flaring. <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/032621-new-mexico-regulatorputs-in-place-rule-requiring-operators-to-eliminate-gas-flaring>.

methane.<sup>50</sup> The commenter notes the World Bank’s Zero Routine Flaring by 2030 Initiative has estimated that flaring results in more than 400 million tons of CO<sub>2e</sub> emissions every year and wastes a valuable resource.<sup>51</sup>

Commenter (0927-ICCR) urges EPA to develop a rule to end routine flaring by 2025. The commenter notes that flaring reduction has been a priority ask from investors in dialogues as well as in resolutions filed with companies in recent years.<sup>52</sup> The commenter states that well-managed companies with whom investors have engaged have adopted commitments to ensure gathering operations are in place before they start drilling, obviating the need for routine flaring. With a wide range of operators – including from historically high-flaring basins such as the Bakken<sup>53</sup> and the Permian<sup>54</sup> – committing to eliminate routine flaring by 2025 or sooner, is clear that this goal is achievable for all. However, the commenter believes that a regulatory floor is needed to manage routine flaring, given its prevalence in basins like the Permian and the unacceptable level of methane emissions from unlit or malfunctioning flares revealed by studies.<sup>55</sup>

Commenter (1297-Lopez *et al.*) calls on EPA to end routine flaring by 2025 either as part of this proposal or as part of a future supplemental rule. The commenter notes that many leading oil and gas companies have announced plans to end routine flaring by 2025 and believes this is a reasonable timeline.

Commenter (0326-Lonqueux) urges EPA to phase out flaring if, as asserted by the November 2021 Proposal, the sustainable solution to GHG emissions is to “incentivize or require the sale or productive use instead of flaring.” The commenter notes that by prohibiting venting, operators must decide whether to invest in flaring equipment or to sell the unwanted gas that was captured from oil wells. The installation of a sales line presents significant uncertainties and costs for producers—access to pipelines, cost of capital, unstable natural gas prices, and cost of operations. The commenter notes that there is a risk that operators without a gas flare will be more inclined to install one if this proposal is passed and those already equipped will continue

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<sup>50</sup> United States, Environmental Protection Agency. “Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases.” Enforcement Alert, vol. 3, no. 9, Oct. 2000, pp. 1-4, [www.epa.gov/sites/default/files/documents/flaring.pdf](http://www.epa.gov/sites/default/files/documents/flaring.pdf). Accessed 10 Dec. 2021; Zhang, Yuzhong, et al. “Quantifying methane emissions from the largest oil-producing basin in the United States from space.” *Science Advances*, vol. 6, no. 17, April 2020, <https://www.science.org/doi/10.1126/sciadv.aaz5120>.

<sup>51</sup> Zero Routine Flaring by 2030 (ZRF) Initiative: Frequently Asked Questions and Answers. The World Bank, [www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna](http://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna). Accessed 10 Dec. 2021.

<sup>52</sup> An example is a resolution filed in 2021 by Trinity Health with PDC Energy, which was withdrawn for a commitment by the company to end routine flaring by 2030, later accelerated to 2025.

<sup>53</sup> Hess Endorses World Bank’s “Zero Routine Flaring by 2030” Initiative, [https://www.iccr.org/sites/default/files/page\\_attachments/\\_revised2021\\_iccr\\_proxyresolutionsandvotingguide-highrezwanchors.pdf](https://www.iccr.org/sites/default/files/page_attachments/_revised2021_iccr_proxyresolutionsandvotingguide-highrezwanchors.pdf), p 48.

<sup>54</sup> Hess Endorses World Bank’s “Zero Routine Flaring by 2030” Initiative, <https://www.hess.com/newsroom/newsarticle/2022-01-27-hess-endorses-world-bank-s-zero-routine-flaring-by-2030-initiative>.

<sup>55</sup> ExxonMobil plans for net zero emissions in Permian Basin operations by 2030, [https://corporate.exxonmobil.com/News/Newsroom/News-releases/2021/1206\\_ExxonMobil-plans-for-net-zeroemissions-in-Permian-Basin-operations-by-2030](https://corporate.exxonmobil.com/News/Newsroom/News-releases/2021/1206_ExxonMobil-plans-for-net-zeroemissions-in-Permian-Basin-operations-by-2030).

<sup>56</sup> Permian Map Analysis, <https://data.permianmap.org/pages/flaring>.

business as usual. Increased routine flaring is a problem because it is inefficient in fulfilling the proposed rule's goals.

Commenter (0734-ATS) notes that shale fracking has become a primary production method of oil and natural gas, and along with it, flaring of associated gas has proliferated.<sup>56</sup> The commenter reports recent findings that indicate that flaring contributes to 0.12 percent of global total disability-adjusted life years (DALYs) attributable to PM2.5 air pollution and 6.51 percent of total DALYs attributable to climate change.<sup>57</sup>

Response I-5-10: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal and section X.H of the preamble to the final rule related to combustion control devices. See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal and section X.F.2 of the preamble to the final rule related to flaring of associated gas.<sup>58</sup> Also, see Volume I, Chapter 17, and Volume II, Chapter 6, for more information related to flaring of associated gas.

EPA notes that owners and operators are allowed to use flares as a control device to meet the emission standard for affected facilities in NSPS OOOOb and EG OOOOc. However, owners and operators must meet the monitoring, recordkeeping, and reporting requirements for flares in NSPS OOOOb and EG OOOOc.

Comments on the Nation Emissions Inventory are outside the scope of this rulemaking. However, EPA is finalizing requirements in NSPS OOOOb and EG OOOOc to ensure that owners and operators who use a flare as a control device on an affected facility monitor the flare to ensure the flare continuously achieves the required emission standard.

### ***5.1.5 Propane Fuel Fed Pilot Flares***

Comment: Commenter (0431-NuEnergy) states that if EPA's goal is to reduce the amount of hydrocarbons that are burned it doesn't make sense to use a propane fed flare with a thermo coupler to burn a very small amount of residual methane from such sources as an oil tank. The commenter asserts that is counterintuitive because in many cases more propane than residual methane would burn. The commenter suggests there needs to be a limit for residual methane in a propane fed flare. The commenter states that aggregate emissions would likely be greater than simply venting or sending emissions to a flare without the extra propane that feeds to a flare.

Commenter (0598-Countrymark) notes that they have provided feedback to EPA multiple times that the requirement to fuel a continuous pilot with supplemental propane increases operating costs and emissions. The commenter states that the wells in the Illinois Basin produce such a low

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<sup>56</sup> Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts. U.S. Dep. Energy Off. Oil Nat. Gas Off. Foss. Energy 1–72 (2019).

<sup>57</sup> Motte, J; Alvarenga, RAF; Thybaut, JW & Dewulf, J. Quantification of the global and regional impacts of gas flaring on human health via spatial differentiation. *Env. Pollut* 291, 118213 (2021).

<sup>58</sup> 87 FR 74779, 74780, and 74792 (December 6, 2022).

volume of gas that the propane used for the pilot light generates more emissions than might be possible without the continuous pilot light.

Response I-5-11: EPA notes that it is not mandating the use of flares in NSPS OOOOb or EG OOOOc. Flares are a control option for various affected facilities within the rule, but other control options such as carbon beds or condensers can also be used in low flow situations where a flare may not be viable, as long as the control device is capable of achieving the level of control specified in the rule.

See Volume II, Chapter 17, Section 17.1.1, for responses to comments on the requirement for a continuous burning pilot flame. See Volume I, Chapter 9, and Volume II, Chapter 13, for responses related to comments on storage vessels.

### ***5.1.6 Flare Design, Operation and Monitoring Requirements***

Comment: Commenter (0742-ADEC) does not see a need for any additional flare monitoring, recordkeeping or reporting that may conflict with already existing requirements. The commenter notes that all flares already operate with a design destruction efficiency of 95 percent or greater. The commenter explains that flares at oil and gas production facilities are primarily safety devices and are regulated by the Alaska Oil and Gas Conservation Commission (AOGCC), who permits and authorizes routine or non-routine flaring for other than safety reasons. AOGCC rules (20 AAC 25.235) already require strict monitoring and accounting of flaring activity to minimize waste of the resource. The commenter provides that improved efficiency and flare performance is provided by flare thermal pilot safety devices and/or flare monitoring cameras maintained by the production center operator.

The commenter (0742-ADEC) supports the continued use of 40 CFR §60.18 requirements and monitoring to demonstrate 98 percent destruction efficiency for flares and vendor information for other control devices. The commenter's authorization mechanisms for flares closely match 40 CFR §60.18 requirements and changing the representable destruction efficiencies of flares used in this NSPS will create a disconnect between the new NSPS, existing NSPS, and state authorization mechanisms. For other control devices, the commenter has the same concern about overlap. The commenter points to the 2016 EPA-453/B-16 publication "Control Techniques Guidelines for the Oil and Natural Gas Industry", which discusses the use of flares and other control devices.

Response I-5-12: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>59</sup>

Comment: Several commenters (0326-Lonqueux, 0723-Ceres, 0757-PESP, 0828-UCS, 0843-EIP, 1282-Earthworks) recommend that EPA ensure the proper operation of flares by frequent inspections and other monitoring requirements (with required repair provisions to return flares to proper operation when issues discovered). Some of the specific comments provided are included in the following paragraphs.

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<sup>59</sup> 87 FR 74792 (December 6, 2022).

Commenters (0757-PESP, 1282-Earthworks) assert that EPA must ensure flares are operating properly and are frequently inspected to ensure they are lit and operating at a maximum efficiency.

Similarly, commenter (0723-Ceres) urges EPA to ensure strong methane emission performance standards by ensuring that flares are operating properly and frequently inspected.

Commenter (0828-UCS) asserts that because flares frequently malfunction, resulting in significant methane emissions due to either becoming unlit or operating at reduced efficiency, EPA must require that in the rare instances where flaring is permitted, monitoring is frequent, and repairs are rapid.

Commenter (0326-Lonqueux) recommends that EPA define an industry standard for the design, operation, and monitoring of flaring devices to limit malfunction, because the presence of undetected dysfunctional flares results in a failure to prevent the release of uncombusted methane into the atmosphere.

Commenter (0843-EIP) requests that EPA establish continuous monitoring requirements for flares. The commenter states that the EPA notes that numerous stakeholders raised concerns that control efficiency of flaring achieved in practice falls below required thresholds. In part to address these concerns, EPA clarifies that the Proposed Rule “would require that when using a flare, the flare must meet the requirements in 40 CFR 60.18 and that monitoring, recordkeeping, and reporting be conducted to ensure that the flare is constantly achieving the required 95 percent reduction.” However, the commenter notes that Subpart A does not actually contain any monitoring requirements that would assure flares are achieving a 95 percent reduction efficiency, and that it is EPA’s obligation to establish these monitoring requirements in Subpart OOOO itself.

Response I-5-13: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal and section X.H of the preamble to the final rule related to requirements for combustion control devices.<sup>60</sup>

Comment: Commenter (0558- Center for Climate and Energy Solutions (C2ES)) suggests that EPA require operators to conduct regular flare combustion efficiency training. The commenter states that if flaring cannot be avoided, operators need to maintain efficient flaring operations to minimize methane emissions. The commenter notes that in the case of flares that combust large volumes of gas, they are often designed with air- or steam-assisted devices that can be optimized to achieve near complete (greater than 98 percent) combustion. This optimization requires increasing the flow of air or steam into the combustion zone of the flare to provide extra oxygen and reduce smoke formation. The commenter contends that although maintaining the efficiency of flare combustion might be challenging if the waste gases have relatively low heating value, monitored and skilled operation can achieve optimum rates that maximize combustion and minimize smoke.

Response I-5-14: EPA is not requiring operators to attend regular flare combustion efficiency training. However, we have added requirements for flares that will ensure they are operated

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<sup>60</sup> 87 FR 74792 (December 6, 2022).



properly and maintain a minimum combustion efficiency. See discussion in section IV.H.2 of the December 2022 Supplemental Proposal<sup>61</sup> and section X.H of the preamble to the final rule related to requirements for combustion control devices.

Comment: Commenter (0843-EIP) contends that EPA is obligated, pursuant to these regulations, to establish continuous monitoring requirements to ensure control devices are operated and maintained in conformance with their designs to ensure compliance. The commenter states that the proposed current approach of leaving it to the permitting authorities to establish monitoring requirements on a piecemeal, permit-by-permit basis makes little sense. They add that leaving it up to state permitting authorities has not worked. For example, in Texas, the commenter reports that the EPA has determined that the most commonly used permits at oil and gas facilities – minor new source review “Permits-by-Rule” – fail to contain adequate monitoring. These permits are available, and widely used, to authorize emissions even at major Title V and New Source Review (NSR) sources.

The commenter (0843-EIP) notes that, and EPA acknowledges, the Agency’s Office of the Inspector General (OIG) found similar issues in its review of numerous permits issued in Colorado and Oklahoma, and its July 8, 2021, report found that “State permitting authorities had difficulty verifying continuous compliance with combustion efficiency requirements for flares and enclosed combustors” and “recommended that the EPA explore additional means to verify continuous compliance in NSPS OOOO and NSPS OOOOa that would provide additional tools for State agencies to properly permit and enforce combustion efficiency.” The OIG Report noted that in the 16 natural gas extraction industry synthetic-minor-source permits it reviewed, 26 permit limits “did not specify a method for determining compliance” while another 55 limits “lacked sufficient direct testing or parametric monitoring to assure that the assumed control efficiency of control devices was being met.” OIG Report at 12-13. The OIG Report also noted that EPA “conducts minimal oversight” of synthetic-minor-source permits and “does not assess whether state and local agencies have developed permit limits in accordance” with EPA’s issued guidance regarding practical enforceability. *Id.* at 6; see also *id.* At 8 (“Neither EPA headquarters nor regional offices conduct regular or routine evaluations or review synthetic-minor-source permits and the limitations adopted by facilities to avoid major source status.”).

The commenter (0843-EIP) provides that the EPA notes that the current standards “require owners and operators to perform an initial demonstration of compliance for all control devices used to meet the standards in the rule and require monthly EPA Method 22 observations to demonstrate continuous compliance with visible emission requirements, in addition to monitoring for the presence of a pilot light.” However, the commenter notes that visible emissions requirement in 40 C.F.R. § 60.18, which prohibits visible emissions from flares for periods longer than five minutes in any consecutive two-hour period, is intended in large part to prevent flares from smoking (which releases soot and black carbon) and does not constitute an adequate means of continuously assuring that flares are meeting their required destruction efficiency. This is especially the case since Method 22 (and Method 9, which Method 22 is based upon) is limited to the observation of “visible” emissions during daylight hours and even then,

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<sup>61</sup> 87 FR 74792 (December 6, 2022).

only under certain weather conditions.<sup>62</sup> The OIG’s Report itself noted that most of the applicable permits it reviewed also “included requirements to periodically verify that a pilot light was operating and to check for visible emissions,” OIG Report at 14, as currently required by 40 C.F.R. § 60.18 and Subpart OOOO. As the Report states, however, “these are not parametric measures that accurately show what control efficiency the device is actually achieving” and “do not assure that the device is continuously meeting its assumed control efficiency of 95 percent.” Id. At 14.<sup>63</sup>

Response I-5-15: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to requirements for combustion control devices.<sup>64</sup>

Comment: Commenter (0843-EIP) recommends that, in the final rule, EPA first determine whether Subpart A performance standards are appropriate for NSPS OOOO flares, or whether more specific standards are needed to assure that NSPS OOOO flares achieve at least 98 percent destruction efficiency. If EPA determines that Subpart A should continue to apply, the commenter asserts that EPA must identify the appropriate monitoring methods intended to ensure compliance as discussed above. If EPA selects different performance standards needed to achieve 98 percent efficiency, the commenter asserts that EPA must identify the monitoring needed to assure compliance with those performance standards. The commenter recommends that the final rule clarify whether EPA has evaluated methods (including operating parameters) that can be used to determine whether flare smoking can be identified after nightfall, when it rains, or under other adverse conditions. For example, the commenter notes that the Proposed Rule states that one OGI expert “noted seeing many flares that were not operating the way they were intended to and that were not adequately designed” and suggested EPA consider using a combination of OGI in conjunction with fugitive emissions monitoring to make sure controls are working. The commenters agree that EPA should consider this route, as well as require video surveillance of flares, which would capture and record any smoking incidents and be a more effective way to identify violations and motivate compliance.<sup>65</sup>

Commenter (0843-EIP) agrees that a 98 percent control efficiency for flares is achievable by design and supports EPA’s November 2021 Proposal to set this higher standard. However, the commenter reiterates that an increased standard of performance is meaningless without the monitoring measures necessary to ensure a 98 percent standard is being met on a continuous basis (let alone the current 95 percent standard). As discussed, the commenter states that EPA is

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<sup>62</sup> See generally EPA Method 22, [https://www.epa.gov/sites/default/files/2019-08/documents/method\\_22\\_0.pdf](https://www.epa.gov/sites/default/files/2019-08/documents/method_22_0.pdf); EPA Method 9, [https://www.epa.gov/sites/default/files/2017-08/documents/method\\_9.pdf](https://www.epa.gov/sites/default/files/2017-08/documents/method_9.pdf).

<sup>63</sup> See also id. at 19 (“EPA has not presented adequate technical information to assure that permitting authorities can continuously verify compliance with ECD-related emission limitations. As noted in our report, verifying that the pilot light is operating and checking ECDs periodically for visible emissions are not compliance actions that accurately demonstrate the assumed control efficiency is being met on a continuous basis. In addition, monitoring the flow rate does not guarantee the assumed control efficiency is being met.”)

<sup>64</sup> 87 FR 74792 (December 6, 2022).

<sup>65</sup> This issue is of particular importance because studies on the effects of visible emissions from flares have shown that they disproportionate impact on historically socioeconomically disadvantaged and vulnerable populations. See, e.g., Lara J. Cushing et al., “Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US.” 2021 Environ. Res. Lett. 16 034032. Accessible at: <https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4>.

obligated to establish monitoring requirements by its own regulations, and evidence from the field demonstrates that leaving it up to state permitting authorities has not been effective.

Response I-5-16: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to requirements for combustion control devices.<sup>66</sup> Additionally, see discussion in section XI.H.2 of the preamble to the final rule related to requirements for monitoring combustion control devices with OGI cameras. See discussion in Volume II, Chapter 17, Section 17.1.3 on use of video cameras for visible emissions monitoring.

Comment: Commenter (0843-EIP) provides details on the level of performance being achieved in practice by flares in the field.

The commenter (0843-EIP) points to ambient monitoring data from the Texas portion of the Permian Basin, which indicate that flares claiming 98 percent destruction efficiency are not achieving that level of performance. Much of the Permian Basin contains very sour gas high in hydrogen sulfide, one of the main reasons that flares are supposed to achieve a 98 percent destruction efficiency. Hydrogen sulfide and sulfur dioxide emissions data are informative and indicate that flares fail to perform as claimed. Texas Permian Basin operators reported more upsets (or “Emission Events” as defined in the Texas State Implementation Plan) than any other TCEQ region, with reported values based largely on oil and gas sources’ assumed 98 percent flare destruction. Flares convert hydrogen sulfide to sulfur dioxide, and so properly functioning Permian Basin flares are expected to release significant SO<sub>2</sub>. Newly installed ambient monitors near Odessa (Ector County) Texas reveal substantially more ambient hydrogen sulfide (and less ambient SO<sub>2</sub>) than expected, indicating that these flares are not performing as claimed.

The commenter (0843-EIP) provides tables that summarize publicly available monitoring data from TCEQ showing ambient hourly hydrogen sulfide (H<sub>2</sub>S) levels in Ector County, Texas. [Table: Goldsmith Monitor Data – 20 Highest Hourly, and Table: West Odessa H<sub>2</sub>S Monitor Data – 20 Highest Hourly presents Date, Time and H<sub>2</sub>S (ppb) data] The hydrogen sulfide levels are higher than the levels that would be expected based on all reported emissions. The commenter suggests that this is likely due in part to un-combusted gas. If flares in this region were performing as claimed, the commenter believes there would be higher recorded ambient SO<sub>2</sub> and lower recorded ambient H<sub>2</sub>S. Instead, the commenter states that the TCEQ’s monitors show dangerously high H<sub>2</sub>S levels, well above the state’s nuisance-based clean air standard of 80 parts per billion.

Response I-5-17: EPA acknowledges the information provided by the commenter.

Comment: Commenter (0843-EIP) supports EPA imposing a 98 percent standard for flares regulated under NSPS OOOO, as well as monitoring requirements to ensure that such flares actually meet the 98 percent standard on a continuous basis, similar to petroleum refinery sector standards. The commenter asserts that if EPA finalizes the rule to include heat pump and velocity as key monitoring parameters, continuous British thermal unit (Btu) meters and continuous velocity meters should also be required. The commenter notes that EPA recognizes technologies such as “digital pilot light monitors, combustion temperature, gas flow meters, gas

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<sup>66</sup> 87 FR 74792 (December 6, 2022).

chromatography (GC) units, and passive remote monitoring of combustion efficiencies at the flare tip” have been used for flares controlling landfill gas.

Response I-5-18: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>67</sup>

Comment: Commenter (0756-Baker Hughes) believes that setting a minimum threshold is not feasible for unassisted flares because it is not possible to control combustion efficiency for unassisted flares. The commenter recommends that EPA require continuous monitoring, reporting and verification. Rather than basing reported emissions on assumptions (e.g., stack is designed to meet xx percent CE), the commenter recommends that reports should be based on real time monitoring. Also, with real time monitoring in place, the commenter believes that operators may find levers to improve the combustion efficiency – effective control depends on accurate measurement.

Response I-5-19: EPA received a similar comment on the December 2022 Supplemental Proposal. EPA’s response to this comment is provided in Volume II, Chapter 17.

#### ***5.1.7 Flare Technology Requirement Recommendations (Including Monitoring Technologies)***

Comment: Commenter (0558-C2ES) suggests that EPA require operators to use technologies that can help maintain the combustion of the flare and provide a back-up ignition in case of failure of a pilot light. The commenter notes that in the case of flares that handle small volumes of gas, they are often equipped with a pilot light that is used to maintain ignition of the flare flame. Most of the pilot lights currently used (e.g., thermocouples) suffer from weather-dependent malfunctions and intermittency problems.

Response I-5-20: See Volume II, Chapter 17, Section 17.1.1, for responses to comments on the requirement for a continuous burning pilot flame. At this time, EPA is not requiring the use of a backup ignition system for combustion control devices. However, it is prudent that operators be alerted promptly when flares are unlit, as unlit flares can be very large emission sources. As such, EPA has added language to the final rule to require an alert to the nearest control room whenever the pilot flame is extinguished.

Comment: Commenter (0756-Baker Hughes) provides that one of the key requirements for flare operation is to maintain net heating value of flare combustion zone gas (NHVcz) of approximately 270 Btu/scf minimum, typically measured by using a gas analyzer or calorimeter. The commenter’s experience is that those instruments are difficult to maintain. The commenter states that field data acquired using flare.IQ (discussed below) indicate that the NHV calculation coming from the sound speed computation method is a suitable alternative for flare gas NHV measurement. NHV from sound speed is within 3 percent when compared to measurements using a GC or a mass spectrometer.

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<sup>67</sup> 87 FR 74792 (December 6, 2022).

Response I-5-21: EPA received a similar comment on the December 2022 Supplemental Proposal. EPA's response to this comment is provided in Volume II, Chapter 17.

Comment: Commenter (0570-Konica Minolta Sensing Americas, Inc.) provides technology information to improve performance and minimize malfunction of flares. The commenter states that there is a big difference in the images obtained by OGI cameras between efficient and inefficient combustion. The commenter points to images in their comment letter (images contained in comment letter include three efficient combustion images, and three incomplete combustion images). With efficient combustion, the commenter explains that the signal from the tip of the equipment stays around the equipment and does not travel far, indicating that the signal is primarily caused by heat or steam. With incomplete combustion, the commenter explains that the signal from the left combustor trails off the image due to the plume of unburned hydrocarbon gas extends downwind. The commenter notes that checking a flaring condition with an OGI camera can provide important clues to understanding the combustion state.

Response I-5-22: EPA agrees that OGI cameras can provide important information regarding the emissions from combustion control devices. See discussion in section XI.H.2 of the preamble to the final rule related to requirements for monitoring combustion control devices with OGI cameras.

Comment: Commenter (0756-Baker Hughes) recommends that EPA set the degree of emissions limitation achievable at 98 percent for assisted flares. The commenter notes that there are commercially available technologies, such as flare.IQ, that achieve a combustion efficiency of 98 percent, and has been installed by operators worldwide. The commenter recommends that EPA require continuous monitoring of combustion efficiency. The commenter notes that technology is currently available to cost-effectively monitor flare performance, such as flare.IQ. (The commenter references Attachment B of their comment letter: Appendix B: Specifications for Baker Hughes flareIQ. This Appendix includes additional information on Baker Hughes flareIQ regarding combustion efficiency and control). The commenter provides the following details on their technology in the body of their comment letter:

Flare.IQ provides the live molecular weight and heating value measurement for flare gas from an ultrasonic flowmeter, without any additional hardware. The technology also provides automatic monitoring of combustion efficiency and flare combustion control for assisted flares and has been used to reduce methane emissions at 130 upstream sites.

Commenters (0729-EWTC, 0756-Baker Hughes) state that flare.IQ was launched in 2017 with an emphasis on the North American market and regulatory compliance with the EPA Refinery Sector Rule 63.670. The commenters note that the technology is now available in all regions and covers oil and gas production facilities. Currently, there are approximately 51 installations worldwide and several pilots are underway in Brazil, Egypt, Russia, United Arab Emirates and Europe. For example, as noted above, significant field validation occurred in 2020 and 2021 when customers started to deploy flare.IQ technology to help better understand, measure and ultimately reduce methane emissions at 130 upstream sites.

Further, the commenters (0729-EWTC, 0756-Baker Hughes) note that it is critical to verify combustion efficiency in real-time because it can deviate for different flares and different plant operating conditions. The flare.IQ technology has a response time of six seconds for assisted flares and has been proven to achieve real-time control for assisted flares.

Response I-5-23: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>68</sup> See discussion in section XI.H.5 and XI.H.6 of the preamble to the final rule related to monitoring assisted combustion control devices and alternative monitoring of combustion control devices.

Comment: Commenter (1371-Frost Methane Labs (Frost)) thinks the cheapest way to reduce emissions from unlit or malfunctioning flares is via continuous visual and/or thermal monitoring. Since most oil and gas flares are open – a no-retrofit solution is to install an internet connected webcam directed towards the flare. Such a device would report data to a server, which would run a machine vision algorithm to determine whether the flare is lit, and to detect obvious malfunctions often indicated by black smoke. This system would automatically alert the operator to any major changes in flare conditions via email or text. To reduce false positive rates, a thermal camera could be attached to this in addition or instead of a visual camera. While less accurate, such a device is significantly lower cost than a camera that detects methane directly – whose costs start at \$50K per unit for just the hardware. The commenter estimates the cost of the full service of visual and thermal imaging, image detection and notification to the operator to be \$1k - \$5k per flare per year – depending on the volume of units in the area, specific characteristics required, length of time to store the data generated and other inspection features that might be useful. Such a service could alert an operator within 20 minutes of a flare issue and provide data on the malfunction from the images preceding the event. The commenter provides that their company can provide this hardware, software and service.

Statistics on flare malfunctions or blows out frequency are not available, nor are statistics on the duration of these outages. The commenter (1371-Frost) provides the following is a conservative estimate: there are daily site inspections, so a flare that blows out will take on average 12 hours to detect, and another 2 to relight. The flow of unlit methane vented over this time is assumed to be roughly constant. The proposed solution reduces detection time from 12 hours to 20 minutes, and the overall venting time from 14 hours to 2:20; this would reduce emissions from unlit flares by 83 percent. If inspections happen every 2 days, and a flare that is extinguished takes an average of 24 hours to be detected, the results are more dramatic with a 91 percent reduction in unlit flare emissions.

The commenter (1371-Frost) provides the following five alternatives for consideration.

Satellite imagery – Flares are visible from a variety of visual and mid wave infrared (MWIR) sources. A publicly available data source which can theoretically detect flare outages is VIIRS. The commenter believes (but are not experts in this field) that it can produce an image at most once a day, assuming there are no clouds. Since this monitoring would not require any onsite hardware, the cost of the system would only consist of software and could therefore be < \$500 / year/flare. In a hypothetical cloudless

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<sup>68</sup> 87 FR 74792 (December 6, 2022).

environment, the average detection time of an unlit flare would be 12 hours. Assuming physical inspections by the operator occur once a day, if they were scheduled 12 hours offset from the satellite flyovers, the average detection time could be reduced to 6 hours. Given our previous assumptions of 2 hours relight time from detection, this would reduce emissions by 43 percent. If the area has frequent clouds, it could be many days between observations and the utility of this method is greatly diminished. There are also private satellites that can capture these images more frequently. However, the costs of tasking a satellite for this purpose are high. Most private satellite constellations are visual, and so would need higher resolution than the VIIRS dataset to be able to detect flare malfunctions. The commenter states that this is only financially feasible if a solution provider could show multiple flares in the same image, and the area is relatively cloud free.

**Methane camera** – The commenter states that a MWIR methane camera is the technically best solution to detect methane from unlit flares and other sources, as it observes the methane directly. However, Methane cameras hardware range from \$50-100K, and additional connectivity and software would be required. A question is whether these systems could come down in price if there was significant adoption, as bearing that cost per site may be very high. If a MWIR camera was shared between sites – a dedicated operator could drive the camera to multiple sites for inspection – the visit frequency would still likely not be more than twice a day and the cost of a dedicated operator is assumed to be an additional \$100k/year.

**Onsite methane ‘sniffer’ detector** – Methane detectors that work by detecting methane molecules that drift by them can be very good for detecting large onsite leaks. These devices are very low cost and can detect leaks from sources other than flares. However, since methane molecules generally rise, and flare tips are mounted relatively high, it is likely that ground-level sniffers will not detect flare outages. The commenter contends that this may be a good solution for some non-flare leak detection.

**Flare Mounted Internet Connected Thermocouple** – For new flares another option is an internet connected device with a thermocouple instead of a camera to measure flare temperature. Unlike the camera method, the device would need to be mounted near the flame itself. The device itself would be marginally cheaper but will not be able to catch incomplete combustion problems, only full flare outages and would not be able to provide imagery leading up to the outage.

**Increase frequency of human inspection of the flares** – Assume that an inspection will happen every 12 hours instead of 24, and that an operator can visit 3 flares in an hour, and costs 100K / year + 30K / year in fuel and vehicle expenses. The operator would visit 24 flares in an 8 hour shift. This would cost 180K / 24 sites = \$4.3k / site / year for a 43 percent reduction in unlit flare emissions. The commenter notes that this is a somewhat more expensive option than the proposed onsite solution of continuous visual and thermal camera monitoring for lower emission reduction results.

Response I-5-24: EPA acknowledges the different methodologies the commenter has submitted. EPA agrees that unlit flares are an issue in this sector. As such, EPA is finalizing a requirement that operators be alerted promptly when flares are unlit, as unlit flares can be very large emission sources, by requiring an alert to the nearest control room whenever the pilot flame is extinguished.

EPA agrees with the commenter that because flare tips are mounted relatively highly, it is unlikely that a handheld methane analyzer will be able to detect emissions from a flare.

See discussion in section XI.H.2 of the preamble to the final rule related to requirements for monitoring combustion control devices with OGI cameras and during audio, visual, and olfactory inspections. See discussion in Volume II, Chapter 17, Section 17.1.3 on use of video cameras for visible emissions monitoring.

EPA is not finalizing a requirement for owners and operators to review flare operation using satellite data, as we are finalizing more localized, site-level controls for these devices. See discussion in section IV.H.2 of the December 2022 Supplemental Proposal and section X.H of the preamble to the final rule related to combustion control devices.<sup>69</sup>

Comment: Commenter (0604-Providence Photonics, LLC (Providence)) provides the following comments on multiple aspects regarding control device efficiency and operation.

The commenter (0604-Providence) notes that, unlike most industrial processes, flares represent a process that occurs in the open atmosphere. As a result, flare control efficiency can be impacted by both process changes and environmental factors. Considering the potential methane emissions attributed to flaring, ensuring sufficient control efficiency across a wide range of process and environmental conditions is essential. Flare manufacturers and operators both have a role to play in ensuring that flares have a high control efficiency. A critical part of ensuring proper flaring is an accurate and affordable measurement technology that can provide both inspection and continuous monitoring. Although there are technical challenges related to flare measurement, there are cost effective technologies available to address these challenges. Some of these technologies are presented below.

Commenter (0604-Providence) provides details on available methods to demonstrate compliance with control efficiency standards. The commenter reports that in recent years there have been some breakthrough technological advancements in the field of measuring flare performance. These advancements provide options that were not available for previous regulatory cycles. Available methods to demonstrate compliance with control efficiency standards are listed in Exhibit 3 of their comment letter and discussed below. [Exhibit 3 of the commenter's letter is a Table, *Available Measures to Ensure that Flares Meet Control Efficiency Standard* includes the 4 Methods and their Implementation, Frequency/Mode of operation, Compliance Criteria, Cost, Maturity of Method, Additional Benefits, Incentives that EPA should provide, and Limitations.] Some of the methods discussed below are suitable for continuous monitoring, some are more suited to periodic inspection, and some can do both.

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<sup>69</sup> 87 FR 74792 (December 6, 2022).



#### Method 1: Indirect monitoring.

The first method listed in Exhibit 3 is the same method EPA promulgated for refineries and ethylene plants. This method established a surrogate parameter (NHVcz/NHVdil) which can be continuously monitored to ensure proper control efficiency. It requires 7 inline instruments to be installed (4 for vent gas line and 3 for assist media line). In the upstream, the vent gas composition tends to be more consistent than those found in refineries and ethylene plants, so perhaps periodic gas composition analysis data could be used in lieu of an online GC, calorimeter, or MS. This would reduce the number of instruments required from 7 to 6. This method is the costliest due to the number of instruments required. The equipment must be installed in line with the process stream, so this method is only suited to continuous monitoring.

#### Method 2: Direct monitoring with VISR.

The second method listed in Exhibit 3 is the VISR method to directly monitor flare combustion efficiency (CE). In December 2019, the commenter submitted a comprehensive information package on the VISR method to another rulemaking docket, Docket EPA-HQ-OAR-2017-0357-0039. That submittal is also applicable to this rule, and the commenter is submitting the same package by reference.<sup>70</sup> The package includes background information on the VISR method, its validation, characterization of its accuracy and precision, and example applications in the field. This direct CE monitoring method is achieved with a single remote sensing device and has numerous benefits (as shown in Exhibit 1 of the commenter's submission [Exhibit 1 is an excel file graphing the OGI Operating Envelope equation for Methane and Butane]), including a lower cost than Method 1 (the method specified in 40 CFR 63 subparts CC and YY). Although it is cheaper than Method 1, the commenter states that it may still be too expensive for continuous monitoring on a single flare to be regulated by this proposed rule. The portability and ease of operation of this method makes it suitable for periodic compliance testing. Although not as effective as continuous compliance monitoring, periodic compliance testing is not uncommon in NSPS subparts for other source categories and in state/federal permits. Periodic compliance testing can be effective if the testing protocols are prescribed such that the testing conditions represent the worst-case operating conditions of the flare in question. It certainly can be used to establish a site-specific operating envelope for a flare – see more discussion on the fourth method later in this section. This can be a low-cost option for this source category when applied to periodic inspections.

#### Method 3: Direct monitoring with simplified VISR.

The third method in Exhibit 3 utilizes a simplified VISR instrument to monitor flare NHVcz/NHVdil, *i.e.*, the same surrogate as monitored by the first method already codified in 40 CFR 63 subpart CC and YY for refinery and ethylene production plants. Method 3 can be considered an alternative test method to measure NHVcz/NHVdil which will be an order of magnitude less expensive than the method specified in 40 CFR 63

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<sup>70</sup> <https://www.regulations.gov/comment/EPA-HQ-OAR2017-0357-0039>.

(*i.e.*, Method 1). The remote device used in this method is a multi-spectral infrared imager, radiometrically calibrated and capable of measuring spectral radiances from the flame, which can be used to derive a signal (called Combustion Index) that is correlated to NHVcz/NHVdil. The multi-spectral imager used in this method is less sophisticated than the one used in the original VISR device for Method 2, therefore the cost is much lower. The cost of this simplified VISR device is comparable to an OGI camera used (and required by this rule) for leak detection. The tradeoff is that it cannot measure flare CE as accurately as the full version VISR, but it can accurately measure NHVcz/NHVdil as demonstrated through validation testing. More information about this new method can be found in Exhibits 4 & 5. [Exhibit 4 includes a paper (Yousheng Zeng and Jon Morris, Remotely Monitoring Flare Combustion Zone Net Heating Value) and a presentation (Yousheng Zeng and Jon Morris, Remotely Monitoring Flare Combustion Zone Net Heating Value (NHVcz) on simplified VISR given at the American Flame Research Committee (AFRC) 2021 Industrial Combustion Symposium. The flare monitoring system presented in the paper and the presentation was referred to as “Mantis Lite,” a brand name for the system that implement the Method 3 in Exhibit 3] [Exhibit 5 of the commenter’s submission, Updated information on simplified VISR method, contains a chart from slide 14 from Exhibit 4 presentation and an updated chart that was updated by adding one more method.] As shown in Exhibits 4 & 5, the commenter notes that the results generated by the prototype of this method agree with the results from the more complex and more expensive Method 1 instrumentation.

This method is suited to continuous monitoring (and closed loop control). Due to its portability and ease of operation, it can also be used for a periodic compliance testing or to establish an operating envelope for a flare. The commercial version of this simplified VISR device for Method 3 has been manufactured. Final tests will be conducted in early 2022 and it is the commenter’s intention to provide additional test results for this method during the comment period for EPA planned supplemental proposal for this rulemaking.

#### Method 4: Establish operating envelope.

The fourth method in Exhibit 3 is to set an operating envelope (OE) for a flare. The OE will be established by varying flare operating parameters, such as vent gas flow rate, vent gas/assist ratio, etc. under different environmental conditions (such as wind speed), while monitoring the flare CE or NHVcz/NHVdil. Lower and upper limits will be established for each flare operating parameter that ensure that flare control efficiency indicated by CE, NHVcz, or NHVdil is higher than the regulatory threshold of 96.5%, 270 Btu/scf, or 22 Btu/ft<sup>2</sup>, respectively. If CE is used as the criteria to establish OE, one of the following methods can be used during the test for establishing the OE: 1) the VISR method (*i.e.*, Method 2 in Exhibit 3), 2) Passive FTIR, or 3) extractive sampling method. If NHVcz or NHVdil is used as the criteria to establish OE, one of the following methods can be used during the test for OE: 1) the method specified in 40 CFR 63 subpart CC, or 2) the simplified VISR method (*i.e.*, Method 3 in Exhibit 3).

Although Method 4 is discussed here as a continuous monitoring method in the context of large assisted flares, Method 4 can also be used by manufacturers of small flares to certify a specific flare model as discussed in the small flare section above.

The commenter (0604-Providence) concludes that the proposed rule will cover a wide range of flares from a primitive well site to a sophisticated gas processing plant. The commenter advocates for flexibility in this rule that allows operator to choose a suitable method from the available methods listed in Exhibit 3 for each flare based on its circumstances (technical feasibility, practicability, cost-effectiveness, and other environmental and economic factors).

Response I-5-25: EPA agrees that it is important to ensure sufficient control efficiency across the range of conditions under which a control device will operate. See discussion in section IV.H.2 of the December 2022 Supplemental Proposal and section X.H of the preamble to the final rule related to combustion control devices.<sup>71</sup>

EPA is finalizing requirements for monitoring the pilot flame, the vent gas flow rate, the vent gas heating value, and the visible emissions from combustion control devices, as well as monitoring assist gas for assisted flares. We are also finalizing a pathway that will let owners and operators seek approval for other methods to monitor the control efficiency of flares and enclosed combustion devices, potentially including the methods described in this comment. See discussion in section XI.H.6 of the preamble to the final rule related to alternative monitoring of combustion control devices.

Comment: Commenter (0604-Providence) asserts that the requirement for monthly Method 22 observations to demonstrate continuous compliance with visible emission (VE) requirements is as ineffective and meaningless as using a one-time initial compliance demonstration for flare control efficiency to represent an emission source whose performance can vary with process and environmental changes. To truly enforce the visible emission standard, the commenter contends that a continuous monitoring method is needed because the visible emissions can occur anytime. Continuous monitoring systems based on visible cameras (*i.e.*, cameras operating in the visible light spectrum) can be an option and has been previously allowed in VE compliance assurance situations such as other NSPS subparts and state/federal permits. There are at least two severe shortcomings of using visible cameras:

1. Visible spectrum cameras can only detect visible emissions during daylight hours.
2. Compliance is based on inspection of visible images (either by an operator or by algorithm), which introduces data management and recordkeeping challenges. Storing and indexing a large number of visible images for audit and compliance determination creates a practical challenge – how frequently should images be captured, stored and indexed, how should images be reviewed and retrieved for compliance determination, especially when the standard is expressed as “no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours” as in current refinery rule for flare [40 CFR 63.670 I]. It is extremely difficult, if not impossible, to make a

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<sup>71</sup> 87 FR 74792 (December 6, 2022).

determination of compliance with this standard based on either a few or a large number of visible spectrum photos captured by the visible camera-based monitoring system.

The commenter (0604-Providence) states that there is now a much more effective and practical solution available which addresses this technical challenge and the shortcomings of visual camera-based compliance methods. The VISR based flare monitoring instruments (both the original VISR device and the simplified VISR device) can continuously monitor visible emissions from the flare as it simultaneously monitors flare CE (in the case of original VISR device) or flare NHVcz/NHVDil (in the case of simplified VISR device). The VISR based flare visible emission monitoring is based on the distinctive infrared radiance emitted by soot (in contrast with radiance from gases) in the flame. This soot-emitted radiance is measured by a metric called Smoke Index (SI). The scale of SI is 0-10. When there is no soot, the SI will be very low, generally below 1 on a scale from 0 to 10. The SI will increase monotonically as the level of soot (and thus level of visible emissions) increases. With the current 0-10 scale, visible emissions are observed when SI is in a range from 1.5-2. Because SI is an unitless index, it could be rescaled to a different range if desired. More importantly, it can be correlated to opacity readings by recording the SI and making opacity readings simultaneously in a calibration test. Because the SI is based on the Infrared radiance from soot, it works in both daytime and nighttime. Therefore, the problem of the visible camera-based smoke monitoring system not being able to work in nighttime is solved.

The commenter (0604-Providence) reports that unlike a visible camera-based system, the results of the VE monitoring by the SI method are not images. The result for each 1-second data cycle in the SI method is resolved to a single numeric value, which can be recorded in the same fashion as any process data such as temperature, flow rate, etc. The SI results can be plotted for easy understanding on how the flare is performing in terms of its visible emissions (see multiple examples of SI time series plots in Exhibits 6). A monitoring method which provides a continuous numeric value makes it a trivial task to determine compliance against a standard such as “no more than a total of 5 minutes during any 2 consecutive hours”. For example, simply averaging the 1-second SI values into 1-minute values would allow the operator to determine if there are a total of five minutes above the threshold in any 2 consecutive hours. If so, a deviation or potential violation of the standard may have occurred. Otherwise, the flare is in compliance with the visible emission standard.

In summary, the commenter (0604-Providence) believes that the current flare visible emission requirements (40 CFR 60.18 general provision, 40 CFR 63 subpart CC for refinery, and 40 CFR 63 subpart YY for ethylene production plants) are inadequate. The visual emissions standard is used to control emission of particulate matter, a criteria pollutant. As these emissions can occur any time during the day or night, regulations should ensure that the standard is met on a continuous basis without regard to the time of day. There are historical reasons why previous regulations have not required continuous visual emissions monitoring, but with the advent of new technologies, the regulations for flare visible emissions should be changed and the new regulations should enforce the flare visible emission standards on a continuous basis, day and night.

Commenter (0604-Providence) questions whether flare monitoring requirements for refineries and ethylene plants are appropriate, practical and/or economically feasible, for this rule. The commenter notes that technology in this field has advanced to provide new cost-effective monitoring methods. Consider that a single device (simplified VISR device described as Method 3 in Exhibit 3) can continuously monitor NHVcz/NHVdil, visible emissions and the presence of a pilot at a cost no more than the OGI camera required for leak detection. The commenter asserts that this allows for simple and cost-effective monitoring and inspections to ensure that flaring in this sector is efficient, and emissions are minimized. The commenter recommends that EPA establish the performance standards and provide multiple compliance demonstration options, such as the ones the commenter identified in Exhibit 3 of their comment letter (see previous comment provided by this commenter) and allow operators to choose what is appropriate for their flares. The commenter requests that small flares covered by these regulations (CO<sub>2</sub> emission rate less than 25,000 tn/yr) be required to demonstrate that the flare meets the performance standard (across the expected operating envelope) with an initial demonstration of compliance and periodic inspections. The commenter request that large flares covered by these regulations be required to demonstrate continuous compliance with the performance standard as required in other sectors. The commenter notes that the difference here is that new technologies offer the ability to achieve these performance standards at a much lower cost.

Response I-5-26: Regarding different requirements for different size control devices, see Response I-5-31. See discussion in section XI.H.6 of the preamble to the final rule related to alternative monitoring of combustion control devices. See discussion in Volume II, Chapter 17, Section 17.1.3 on use of video cameras for visible emissions monitoring.

EPA disagrees that monthly EPA Method 22 visible emissions observations are ineffective. However, EPA acknowledges that is important for owners and operators to be aware of issues with control devices as quickly as possible. The largest issue with combustion control devices is the incidence of unlit control devices. As such, in addition to the requirement to have a continuously lit pilot flame, EPA has added a requirement for an alert to the nearest control room whenever the pilot flame is extinguished.

Comment: Commenter (0604-Providence) states (and provides supporting figures) that the VISR methods (both the original VISR method and the simplified VISR method) described in Exhibit 3 of their comment letter (see previous comment provided by this commenter) are viable methods of monitoring flare pilot flame. The commenter recommends that this new rule be structured to allow for adoption of this new method for monitoring flare pilot presence.

[Comment letter submissions includes a Figure (Figure 3) of 3 flare images side-by-side. The Figure shows a lit flare with a small purge rate and the same flare when there was no vent gas and only the flare pilot was on. On the left of the figure is an image of the test flare in visible light spectrum. In the middle of the figure is a VISR image of the same flare when it was idling at a purge rate. On the right of the figure is a VISR image of the same flare when there was no vent gas and only the pilot was lit.]

The commenter notes (0604-Providence) that the VISR image shown in Figure 3 of their comment letter submission is for illustration purpose. The presence or absence of the pilot flame

will be reflected in the VISR data stream, and no images will be stored. There is no additional data management needed for this feature. When the pilot detection feature is enabled, the VISR system will flag the data and raise alarm when no pilot flame is detected. Additionally, the commenter reports that VISR instruments can distinguish the combustion gases of the pilot flame from the hot metal pilot hood. Another example of flare pilot captured by the VISR instrument is shown in Figure 4 of their comment letter submission. [Figure 4 of the commenter's submission includes a single image of a flare captured by VISR instrument.] In this case, the commenter notes that the flare main flame was lifted, and the two pilots were visible by the VISR instrument. In this VISR image, the metal pilot hood is shown in blue color and the pilot flame in red color. The distinction between the two is based on the different IR spectral characteristics between solid material (the metal hood) and the gaseous material (the pilot combustion products).

Commenter (0604-Providence) informs that pilot monitoring based solely on the temperature of the pilot hood (either thermocouple-based or single spectral IR based) will have a delayed response when the pilot flame goes out because it will not alarm until the metal hood cools down. Detection of pilot combustion gases, such as the VISR method, will be instantaneous. When the pilot flame goes out, there will be no pilot combustion gases and the VISR device will detect this without any latency. It should be noted that if the flare is operating properly and the pilot flame is engulfed by the main flame, the VISR device will not be able to distinguish the pilot flame from the main flame. However, this will be a moot point because the purpose of monitoring the presence of the pilot flame is to ensure the flare is lit. If the main flame is present, this purpose has been accomplished. This new rule should be structured to allow for adoption of this new method for monitoring flare pilot presence.

Response I-5-27: See discussion in section XI.H.6 of the preamble to the final rule related to alternative monitoring of combustion control devices.

Comment: Commenter (0604-Providence) provides comments on “how OGI may be used to identify poor combustion efficiency” and “how OGI has been used to evaluate the heat signature of gases exiting the top of the stack and/or presence of any unburned hydrocarbon trailing or advective plumes.” The commenter recommends OGI cameras not be used to determine the efficiency of a flare but could be used to evaluate whether a flare is lit.

The commenter (0604-Providence) understands that the term “OGI” in these questions refers to the typical single spectral Infrared (IR) cameras used for detection of fugitive gas plumes and referenced in other parts of this proposed rule. Although in some special circumstances OGI can hint at poor combustion (further discussions on this subject later), its use for evaluating flare performance is unreliable in most cases and can be misleading. OGI cameras utilize a single narrow bandpass filter to image gas plumes. OGI will be able to image a plume against the background if 1) the plume contains gas (or gases) that has IR spectral bands which overlap with the transmission curve of the bandpass filter in the OGI camera (*e.g.*, spectral bands in the wavelength of 3.2-3.4 micrometer); 2) the temperature of the plume is different from the temperature of the background (ref. to as delta-Temperature or  $\Delta T$  in the OGI field); and 3) there is sufficient amount of such gas(es) in the plume that can create sufficient contrast in the OGI imager against the background. The commenter has used the term “OGI triangle” to describe

these three prerequisite conditions for gas imaging. The plume from a flare or enclosed combustor can contain aerosols, *e.g.*, small amounts of carbon soot, particles of trace amounts of inorganic substances in the feed and carried over to the plume, or even liquid droplets. Although these aerosols may have very low concentrations, the IR radiance from them can be quite high relative to the sensitivity of the OGI camera due to the high temperature of the post-combustion gas plume (*i.e.*, extremely high  $\Delta T$ ). Even though the IR spectrum of the radiance emitted by these aerosols does not have “peaks” overlapping with the OGI camera bandpass filter as hydrocarbon gases do (*i.e.*, the IR spectrum of the aerosol will be broad, resembling that of a blackbody or graybody), the radiance in the spectral region of an OGI can still be comparable to that of gases due to the fact that aerosols are much more dense than gases and the temperature can be much higher than the background (high  $\Delta T$ ). As a result, the hot post-combustion gas plume is usually visible by OGI cameras even when they are not visible by naked eyes. This is often misinterpreted as evidence of hydrocarbon in the post combustion plume when it is more typically evidence of aerosols which do not necessarily indicate good or poor combustion.

Even if the contribution from aerosol radiance is negligible and the radiance emitted from the flame and received by the OGI camera is predominately from combustion gases, the commenter (0604-Providence) explains that the images captured by a single spectral OGI camera cannot be used to assess the combustion efficiency of the flare, not even qualitatively. The radiance from the combustion gases will be a function of the temperature of the gases and the size of the plume. Both variables can change from flare to flare and from one condition to another within the same flare. An image with a single infrared spectrum will not provide sufficient information to assess the performance of the flare. Only multi-spectral or hyper-spectral imaging with a sophisticated and quantitative algorithm can be used to assess and measure the flare performance.

The commenter (0604-Providence) adds that an operator of the OGI camera will see the post-combustion gas plume but cannot tell if it contains unburned hydrocarbon or the normal presence of aerosols at a high temperature. Therefore, they suggest that the mere presence of a trailing gas plume from a combustion device in the OGI imager is generally inconclusive in terms of judging the combustion efficiency of the combustion device. The public comment submission includes a Figure (Figure 5). Figure 5 includes example images in a single spectral band comparable to the common OGI cameras. By examining these images, the commenter states that one would not be able to tell the difference. However, the commenter states that they were taken from the same flare operating under drastically different conditions and they represent different flare combustion efficiencies as indicated in the caption of Figure 5.

[Figure 5 of the public submission include 3 images side-by-side of a single spectral image of the same flare under different conditions and having different combustion efficiencies. Left: CE = 97.2 percent. Middle: CE = 88.3 percent. Right: CE = 98.5 percent]

The commenter (0604-Providence) continues by stating that there may be a few exceptions. For example, if there are split trailing plumes in the OGI imager following a combustion device, it could indicate a poor combustion. In this scenario, the gases and aerosols are separated at some distance downwind from the flare tip due to their density differences, and each of the split plumes still maintains some cohesive shape with sufficient concentration and temperature difference against the background (*e.g.*, sky background). Although the OGI camera cannot

differentiate the gas and aerosols as discussed above, the fact that gravity has separated the plume into two segments is a strong indication of poor combustion. To observe this phenomenon and conclude poor combustion, some prerequisite conditions must simultaneously exist: there must be sufficient masses in both the unburned hydrocarbon plume and the aerosols plume that have survived the atmospheric dispersion and dilution of the atmospheric air mass before and after they are separated by gravity, and they must separately maintain high enough optical density and temperature differential against background far enough downwind from the release point. If these conditions are not met, this phenomenon will not be observed even if the combustion device has a poor combustion efficiency. On the other hand, the commenter notes that the absence of such a phenomenon does not prove a high combustion efficiency.

If a flare is unlit due to pilot malfunction, the commenter (0604-Providence) informs that an OGI camera will be able identify such a condition. The plume leaving the flare tip could be a dark plume (absorptive plume) or white plume (emissive plume) depending on the temperature of the vent gas(es) relative to the background (usually the sky) temperature, and there should be no combustion at the tip (as indicated by a very bright plume, usually saturating the associated pixels) in the OGI camera. For a lit flare, it is not possible to assess its combustion efficiency with an OGI camera except under some special conditions as discussed above. For this reason, the commenter recommends that OGI cameras not be used to determine the efficiency of a flare but could be used to evaluate whether a flare is lit.

Response I-5-28: In the final rulemaking, EPA is not requiring owners and operators to continuously monitor the flare efficiency with an OGI camera, as we agree that an OGI camera can provide a qualitative assessment of the flare operation but cannot provide the control efficiency being achieved. See discussion in section XI.H.2 of the preamble to the final rule related to requirements for monitoring combustion control devices with OGI cameras.

Comment: Commenter (0604-Providence) provides comments on OGI continuous flame imaging systems. The commenter states that new technologies that provide real-time measurement of control efficiency do exist, and they are listed in Exhibit 3 of their public comment submission (see earlier comment from this commenter and cited Exhibit 3), particularly Method 2 and Method 3 in Exhibit 3. However, using the flame size and temperature captured by an OGI or an IR imager as a surrogate for flare efficiency is not scientifically sound. First, the flame size captured by the IR imager is simply a function of flaring rate and the orientation of the flame relative to the imager. These variables have no definitive relationship with flare combustion efficiency. A flare may have similar size but significantly different efficiency, or vice versa. Figure 5 discussed above gives examples to demonstrate this point. Secondly, the temperature captured by these imagers are a measurement of “apparent temperature” even if the imagers are radiometrically calibrated. Because the flame consists primarily of combustion gases (which can be drastically different from the blackbody that is used to radiometrically calibrate the IR imager), the apparent temperature measured by the IR imager may be significantly different from the actual combustion temperature depending on variables such as optical density (related to flame depth along the camera’s line of sight) and the amount of aerosols in the flame, and they will be significantly different from pixel to pixel (representing different parts of the flame). If the maximum apparent temperature is used based on a single pixel (or several pixels), it may represent a small parcel of the combustion gases near the center of the flame and may not be



representative of the combustion temperature of the flame (as a whole). This maximum, localized apparent temperature tends to be the same regardless of combustion conditions. Through the commenter's testing, the commenter has observed such a stable apparent flame maximum apparent temperatures while the flare combustion efficiency varied significantly – as shown in Table 1. [Comment included Table 1: Flare combustion efficiency (% - percent) verses maximum apparent temperature(C), comparing 8 separate cases of flares]

As a result, the commenter (0604-Providence) recommends that EPA not consider flame size or flame temperature as surrogate parameters for flare efficiency as there is no scientific merit to this approach. Instead, the commenter requests that the EPA consider technologies which directly measure efficiency (such as Method 2 in Exhibit 3) or those which measure a parameter which is proven to be correlated to flare efficiency (such as Method 3 in Exhibit 3 of the commenter's public comment submission).

Response I-5-29: EPA is not approving the use of continuous OGI or infrared imaging as techniques for monitoring control efficiency in the final rule. See discussion in section XI.H.6 of the preamble to the final rule related to alternative monitoring of combustion control devices.

Comment: Commenter (0604-Providence) provides comments on methane emission rate from flares. The commenter strongly recommends that EPA structure this rule with allowance for operators to utilize new, cost-effective, easy-to-install and operate, and environmentally beneficial technologies such as the simplified VISR device described here.

For quantifying methane emissions from flaring, the commenter (0604-Providence) reports that the most common method currently used is to apply a presumed control efficiency (typically 98%) to the flowrate of the flare. This method is highly inaccurate. By definition, using this method will produce a methane emission rate which is proportional to the flow rate. The higher the flowrate, the higher the methane emission rate, *e.g.*,  $\text{emission rate} = (100\% - 98\%) \times \text{flowrate}$ . In practice, when the flare gas flowrate is low, the chance for over-assist is higher and the risk for lower control efficiency is higher, which can lead to a higher emission rate than the emission rate based on the presumed control efficiency. On the other hand, the commenter adds that when the flare gas flowrate is high, the flare tends to operate at a higher combustion efficiency and the emission rate is likely lower than the emission rate calculated based on the presumed control efficiency.

The commenter (0604-Providence) refers to Figure 6 of their comment letter. [Note: Figure 6 of the commenter's public comment submission is entitled "Methane Emission Rate (Measured vs. Estimated)."] The Figure compares methane emission rate to estimated and measured methane by various methods.] They note that the Figure is based on testing conducted by the commenter at John Zink's flare testing facility in Tulsa, OK. The flare tip was the same flare tip used for the 2010 TCEQ flare study. The grey line represents the natural gas flaring rate in lb/hr (plotted on the secondary y-axis). This flaring rate is measured by flowmeter with temperature and pressure compensation (referred to as the Ref. method for flowrate). In this dataset, the commenter explains that the vent gas was natural gas with a methane concentration of 90 percent. The orange line [illustrated in the figure] represents the calculated methane emission rate (lb/hr) using the common method of assuming 98 percent control efficiency. Note that the orange line

parallels the grey line because the emission rate is exactly proportional to the flaring rate (by 2 percent) when a presumed 98 percent control efficiency is applied.

The commenter (0604-Providence) continues that the green line [illustrated in Figure 6 of the commenter's public comment submission] represents the actual methane emission rate based on the flowrate measured by flowmeter (with temperature and pressure compensation) and flare combustion efficiency measured by the VISR method (*i.e.*, Method 2 in Exhibit 3 of the commenter's public comment submission). The commenter considers this to be the reference method for the methane emission rate as it is the most accurate method available. During this study, the level of assist was changed for each flaring condition to produce a range of control efficiencies. The commenter states that the data shows that the actual methane emission rate as measured by the reference method (the green line in the figure) is significantly different than the estimated 98% control efficiency (orange line). As shown Figure 6 of the commenter's public comment submission, the green line is significantly higher than the orange line when the flare was over-assisted (*e.g.*, Test ID T07a-e near the middle section of the chart) indicating that actual methane emissions are much higher than the 98 percent control efficiency estimate. Inversely, when the flaring rate is high and it was not over-assisted (*e.g.*, Test ID T10b-T11k), the orange line is significantly higher than the green line indicating that actual methane emissions are much lower than the 98% control efficiency estimate.

The commenter (0604-Providence) informs that the purple line in Figure 6 of the commenter's public comment submission is the methane emission rate as measured by the low cost simplified VISR method (Method 3 in Exhibit 3 of the commenter's public comment submission) using flow data provided by the test facility. The commenter also used the simplified VISR device to measure the flowrate. The use of the VISR method for flare flow rate measurement is explained in Exhibit 7 of the commenter's public comment submission. The blue line in the Figure 6 of the commenter's public comment submission is the methane emission rate measured solely by the simplified VISR method (Method 3 in Exhibit 3) without the flow measurement provided by the test facility. In Figure 6 it is labeled as "Measured Solely by Mantis Lite" (Mantis Lite is brand name for a device using Method 3). As stated in a previous section and in Exhibit 3, Method 3 of the commenter's public comment submission directly measures NHVcz. For the purpose of measuring methane emissions, the commenter developed a non-linear equation between NHVcz and the flare CE based on test data. Although the CE measured by this method is not as accurate as the CE measured directly by Method 2 in Exhibit 3, it has a significant benefit of utilizing a low-cost device. The results of this method (the blue line in Figure 6 of the commenter's public comment submission) are close to the most accurate method (the green line in Figure 6 of the commenter's public comment submission) and much more accurate than the current 98% control estimate (the orange line in Figure 6 of the commenter's public comment submission). Comparing the blue line and purple line in Figure 6 of the commenter's public comment submission), it is seen that the simplified VISR method provides the same accuracy with and without a flow measurement. The commenter states that the combination of the CE and flowrate measured by this simplified VISR method allows us to measure the methane emission rate using a single, low-cost remote sensing device.

The commenter (0604-Providence) explains that this data shows that this method will be applicable even when the flare is not equipped with a flowmeter to measure the flare gas flow

rate. If the flare already has a flowmeter installed, the flowrate measured by the flow meter and the CE measured by the simplified VISR method can be used to calculate the methane emission rate. This result is represented by the purple line in Figure 6 of the commenter's public comment submission.

The commenter (0604-Providence) refers to a table in their comment letter that presents a summary of methane emission rates measured by the four different methods in Figure 6 of their public comment submission. They explain that the results are presented in both emission rate (lb/hr) and the bias with respect to the Reference method. The data has been segmented into two groups: "Proper Operation" and "Over-assisting." The commenter states that the most accurate method is the Reference method, which is also an expensive method. The 98 percent control method is the least expensive method (the cost will be the flowmeter and temperature and pressure instruments). However, it overestimates methane emissions by 304 percent when the flare is operated properly and underestimates methane emissions by 69 percent when the flare is over-assisted. In comparison, the simplified VISR method (Method 3 in Exhibit 3) drastically reduces the bias at a cost comparable to an OGI camera for leak detection. The benefit of using Method 3 (with or without a flowmeter) is clearly demonstrated in Table 2 (of the commenter's public comment submission. [Note: Table 2 of the commenter's submission is titled "Flare methane emission rate measured by four different methods." Table 2 compares flared methane emissions rates by 4 different references: Reference Method, 98 Percent Control, Method 3 w/Flowmeter and Method 3 w/o Flowmeter.] The commenter states that the same device can simultaneously monitor visible emissions and presence of the pilot flame at no additional cost. The commenter strongly recommends that EPA structure this rule with allowance for operators to utilize new, cost-effective, easy-to-install and operate, and environmentally beneficial technologies such as the simplified VISR device (Method 3) described here.

Response I-5-30: EPA acknowledges the information provided by the commenter. See discussion in section XI.H.5 and XI.H.6 of the preamble to the final rule related to monitoring assisted combustion control devices and alternative monitoring of combustion control devices.

### ***5.1.8 Flare Recordkeeping and Reporting Requirements***

Comment: Commenter (0604-Providence) recommends that EPA promulgate separate reporting requirements (or standards) for flares based on the flare size or flaring rate.

Response I-5-31: EPA disagrees with the commenter. It is important to ensure that any control device used to achieve the emission standard for an affected facility is capable of continuously meeting the standard. All control devices must meet the same standard (the emission standard for the affected facility), and as such, separate standards cannot be applied to different sizes of control devices. EPA also disagrees that separate reporting requirements should apply to different control devices, as the goal of using any control device is to ensure that the emission standard for the affected facility is achieved. Recordkeeping and reporting are necessary components of compliance used to document that the control device is working properly, and the affected facility is in compliance with the emission standard.

### 5.1.9 Standard Recommendations Based on Flare Size

Comment: Commenter (0604-Providence) provides specific recommendations for regulatory requirements for both small and large flares.

Commenter (0604-Providence) states that flares that will be regulated under the proposed rule can be segregated into two categories: large and small. The distinction between these categories can be debated, but for the purpose of these comments the commenter will refer to large flares as those with a CO<sub>2</sub> emission rate exceeding 25,000 tpy. NETL collected and published data on flare size distribution which suggests that large flares account for about 10 percent of all flares.<sup>72</sup> The commenter provides a figure (Figure 2 of their comment letter) that shows the distribution of flares in the Permian, Bakken and Eagle Ford basins. [Figure 2 of the commenter's submission shows the distribution of flare sizes in Permian, Bakken and Eagle Ford. Source: NETL, 2020. The figure is a line graph that illustrates as the feed flow rate (mscfd) increases the number of flares decrease.]

The commenter (0604-Providence) asserts that methane emission inventories to date have been compiled by assuming that all flares have the same efficiency (typically a value of 98 percent is used) under all process and environmental conditions. The commenter believes that applying this assumed control efficiency to all flares without regard to actual performance is not prudent as it will lead to regulations and expenditure of resources in areas that do not deliver the desired control of methane emissions. For example, the commenter notes that if you apply a 98 percent control efficiency to the NETL flare distribution without regard to actual performance, you will reach the conclusion that most of the methane emissions come from small flares and regulations should focus on that category. However, when the actual efficiency is considered, the conclusion may be different. The commenter has measured hundreds of flares in these basins and found that the small flares tend to have highest efficiency while large flares can demonstrate lower efficiencies and more opportunity for optimization. For this reason, the commenter recommends that EPA consider the inaccuracy in current methane emission inventories when proposing flaring rules for this sector.

Commenter (0604-Providence) states that small flares tend to be simple in design without significant control methods to adjust the flare performance based on process or environmental conditions. Because of the relatively simple design and lack of control mechanism, the performance of these flares is often more reliant on the flare design (*i.e.*, manufacturer) rather than the flare operator. For these types of flares, the commenter recommends that measures employed to ensure the control efficiency standards have the following elements:

1. *Flare manufacturer's performance certification.* The commenter recommends a regulatory process for flare manufacturers to certify the performance of a specific flare model across the operating range (analogous to the way mobile source emissions are controlled – auto manufacturers are responsible for meeting emission standards). The commenter recommends that flare manufacturers complete performance testing to establish an operating envelope for each flare model which guarantees the desired control

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<sup>72</sup> Submission Figure 2: Distribution of flare sizes in Permian, Bakken and Eagle Ford. Source: NETL, 2020. The figure is a line graph that shows as feed flow rate increases the number of flares decreases.

efficiency across the expected range of process and environmental conditions. This range of conditions should include, at a minimum, the range in flaring rates (*i.e.*, turn down ratio), gas composition and wind speed. The commenter suggests there should be an option for the operator to do this performance testing, but it will be far more efficient for the flare manufacturer to certify the flare design and prescribe the operating envelope to the operator. In addition to efficiency, the commenter believes this approach will produce more consistent results across the sector because establishing flare performance and operating envelope is not a trivial task and doing so for such a large number of flares in the field will likely yield less consistent (and less accurate) results, especially considering many of these flares are operated by small businesses with limited resources and technical expertise.

2. *Performance testing on installation.* The commenter recommends an initial compliance test to confirm that the control efficiency is achieved, similar to the compliance demonstration requirements in the 40 CFR 60.18. The operator should have some flexibility when demonstrating initial compliance with two options proposed here:
  - a. The operator can demonstrate that they are operating within the manufacturer's established operating envelope and reference the manufacturer's performance data to demonstrate initial compliance.
  - b. The operator can perform a direct measurement of efficiency to demonstrate initial compliance.
3. *Periodic inspection.* After initial compliance demonstration, the commenter recommends that the flare be inspected at a fixed interval to ensure that it is meeting the control efficiency. Like the initial demonstration of compliance, this periodic inspection could be a direct measurement of control efficiency or a demonstration that the flare is operating within the flare manufacture's established operating envelope. When establishing the interval for the periodic inspection, the commenter recommends that EPA factor in the life cycle of these small flares. The requirement for periodic inspections should be waived if the flare is equipped with a continuous monitor which ensures that the flare is meeting the desired control efficiency.

The commenter (0604-Providence) asserts that large flares tend to be more complex and typically use assist media (*e.g.*, air, steam, or additional combustible gas) to influence the flame dynamics and achieve better combustion efficiency with smokeless operation. When the assist media is not properly administered (*e.g.*, over-assist), the effect could be the opposite of the intended outcome resulting in low combustion efficiency. With the exception of flares regulated under the Petroleum Refinery Sector Standards (40 CFR 63, subpart CC) and NESHAP for ethylene production facilities (40 CFR 63, subpart YY) where continuous monitoring of flare performance is required, the commenter believes that the current measures to ensure that these large flares meet the control efficiency standards (*e.g.*, the heat content in the vent gas and exit velocity in 40 CFR 60.18) are either non-existent or ineffective. These large flares can be over-assisted for long periods of time without the operator having any knowledge of the problem, resulting in emissions much higher than assumed efficiencies. This problem was observed in the refinery and ethylene sectors, prompting regulations to require continuous monitoring of flare efficiency. The commenter recommends that large flares regulated under this proposed rule be

required to continuously demonstrate compliance with the applicable control efficiency standards.

Previous standards have only considered exit velocity and the heat content of the vent gas. This may be sufficient for unassisted flares, but for assisted flares, the commenter states that calculating the heat content based solely on the vent gas and not accounting for the diluting effect of assist media (*e.g.*, air for air-assisted flares) is not an adequate measure of flare control efficiency. The effect of the assist media can cause a very low combustion efficiency if it is not adjusted properly to the changing vent gas flowrate. This is the premise of the more recent requirements in 40 CFR 63 subparts CC and YY where a surrogate parameter is established to account for the effect of assist media. For steam assisted flares, Combustion Zone Net Heating Value (NHVcz) is the surrogate parameter which is continuously monitored to demonstrate compliance with the established performance standards. For air assisted flares, Net Heating Value Dilution Parameter (NHVdil) is the surrogate parameter. NHVcz/NHVdil has been codified in 40 CFR subpart CC and YY for flares at petroleum refineries and ethylene plants, respectively, and should be applied to the large flares in this regulation. While NHVcz/NHVdil monitoring is a good way to ensure proper control efficiency for assisted flares, it is an indirect method using a surrogate parameter to demonstrate compliance with control efficiency standards. EPA should also consider recent technology advancements which provide a direct measurement of control efficiency, such as the Video Imaging Spectral Radiometry (VISR) method (Zeng, *et. Al.*, 2016; Morris, *et. Al.*, 2019a, Morris, *et. Al.*, 2019b) which has been validated through extensive testing. These direct measurement technologies can provide an environmental benefit beyond the indirect methods by allowing for closed loop control and continuous and autonomous optimization of the flare performance.

Commenter (0604-Providence) believes that current regulations are also inadequate with respect to the frequency of determining compliance with performance standards. The commenter notes that the current NSPS OOOO and OOOOa requirements require only an initial demonstration of compliance. According to the commenter, considering the wide variability of performance from flare operations, an initial one-time demonstration of compliance is nearly meaningless. For small flares, the commenter proposed periodic inspections to ensure compliance, but for large flares in this sector continuous monitoring should be required. The continuous method should directly monitor the control efficiency or monitor a surrogate parameter, such as NHVcz, to ensure that the required control efficiency is achieved under all process and environmental conditions. Large flares can have high flaring rates, so even a relatively short period of low efficiency can produce methane emission rates that are an order of magnitude higher than current emission inventory estimates. The commenter contends that continuous monitoring for these flares presents the best opportunity for control of methane emissions from flaring.

Response I-5-32: Regarding different requirements for different size control devices, see Response I-5-31. See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>73</sup> See discussion in section XI.H.5 and XI.H.6 of the preamble to the final rule related to monitoring assisted combustion control devices and alternative monitoring of combustion control devices.

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<sup>73</sup> 87 FR 74792 (December 6, 2022).

Comment: Commenter (0809-Earthjustice) highlights specific examples of gaps or shortcomings in the NSPS proposal that they note are also relevant to the NESHAP rulemaking. The commenter recommends that EPA seek to address these areas in the NSPS rulemaking and the NESHAP reconsideration and section 112(d)(6) review to directly address these areas with respect to air toxics emissions and their effects on human health.

The commenter (0809-Earthjustice) recommends that EPA update the NSPS flare standards application to the oil and gas sector given that the NSPS general flare standards under 40 C.F.R. § 60.18 are nearly identical to the NESHAP general flare standards under 40 C.F.R. § 63.11, which are overdue for review. In doing so, the commenter suggests that the EPA follow the improved flare operational and monitoring requirements of the 2015 Refinery Rule and recent NESHAP rulemakings for chemical and petrochemical source categories. However, the commenter states that EPA should not add the malfunction loopholes included in some of these rules.<sup>74</sup>

Response I-5-33: This comment on NESHAP is outside the scope of this rulemaking under CAA section 111.

## **5.2 Other/All Combustion Devices**

### ***5.2.1 Combustion Efficiency***

Comment: Several commenters do not support mandating the requirement for combustion control devices to attain a 98 percent control efficiency. Some of the specific comments provided are included in the following paragraphs.

Commenter (0808-API) does not support the proposed change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from those affected facilities.

Commenter (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) contends that EPA should not mandate the requirement for combustion control devices at oil and gas well sites to attain 98 percent destruction efficiency but allow it as an option in situations where it is cost effective and feasible. The commenter recommends that EPA provide incentives to operators where use of this equipment is feasible. The commenter recommends EPA avoid burdensome monitoring requirements that dissuade operators from using combustion control devices that can attain 98 percent destruction efficiency.

The commenter (0810- Petroleum Alliance-OK) states that combustion control devices are engineered and operated under certain conditions (*e.g.*, consistent flows and appropriate gas

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<sup>74</sup> See, *e.g.*, RISE St. James et al., Petition for Reconsideration of the National Emission Standards for Hazardous Air Pollutants (NESHAP): Miscellaneous Organic Chemical Manufacturing (MON) Risk and Technology Review 31-43 (Oct. 13, 2020) (discussing loopholes), <https://www.regulations.gov/comment/EPA-HQ-OAR-2018-0746-0242>; RISE St. James et al., Petition for Reconsideration of Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production 8-21 (Sep. 4, 2020) (discussing loopholes), <https://www.regulations.gov/comment/EPA-HQ-OAR-2017-0357-0075>.

quality) to attain a 98 percent destruction efficiency. The commenter notes that this may be appropriate in certain situations (*e.g.*, newer wells). However, as wells decline, gas flows and pressures decrease or become variable, and it becomes increasingly difficult to ensure complete combustion to achieve the 98 percent DE. The commenter believes that the use of complex control devices and monitoring/automation systems are possible to implement for very small vapor streams, but they are significantly more costly, especially for marginal/low production wells, and may make the well uneconomical. Also, the commenter adds that the gas quality may also be a factor preventing the use of combustion control devices with higher destruction efficiencies.

Commenter (0817-GPA) supports the continued use of a 95 percent control efficiency requirement, particularly for midstream activities, due to cost and operational flexibility. The commenter notes that the November 2021 Proposal provides a logical rationale for retaining the 95 percent control efficiency and the Technical Support Document (TSD) discusses the real difficulties of continuously maintaining a 98 percent control efficiency. The commenter notes that one of the biggest barriers identified in the TSD is that, in order to reach such a high destruction efficiency, “monitoring systems require electricity.”<sup>75</sup> The commenter contends that, as is well-documented, many midstream sites are remote, unmanned locations that lack consistent access to electricity. The commenter notes that the cost of running electricity to sites—which is difficult to estimate on an industry-wide basis—was not included in the TSD cost estimate. Even without the added cost of electricity, the TSD estimated that “capital costs increased greatly” for a 98 percent destruction efficiency, “going from \$80,000 to \$430,000” while also increasing annualized costs.<sup>76</sup> The commenter agrees that these amounts are not cost-effective at oil and gas facilities for VOC or methane control.

Further, the commenter (0817-GPA) contends that requiring 98 percent destruction efficiency would greatly limit operational flexibility. Whereas 98 percent efficiency can only be reached with additional equipment to maximize flare combustion, the 95 percent efficiency standard is technology neutral. The commenter notes, for example, this allows for necessary maintenance downtime for VRUs.

Commenter (0817-GPA) recommends a new rulemaking proposal if EPA reconsiders its position on combustion efficiency. If, based on public comments, EPA elects to require a higher standard (such as a 98 percent efficiency), the commenter recommends a new proposed rulemaking be issued to provide stakeholders with sufficient new information and the opportunity to comment. The commenter asserts that the November 2021 Proposal has included little to no information that would support a change in EPA’s position, such as proposed regulatory language, the costs and benefits associated with such a change, and whether certification to a 98 percent combustion efficiency is even possible for affected devices. Moreover, the commenter contends that significant capital investments have been made and business structured based on the well-established 95 percent efficiency standard and with the substantial new demands that may result

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<sup>75</sup> Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Background Technical Support Document (Oct. 2021) (“TSD”) at 6-23.

<sup>76</sup> *Id.*



from the November 2021 Proposal as is, any increase in required efficiency to 98 percent even for only select control devices, should be considered in light of the overall burdens imposed.

Response I-5-34: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>77</sup>

Comment: Commenter (0604-Providence) recommends that EPA set the control efficiency standard at 98 percent. The commenter notes that the most common control devices in this sector are combustion devices. The commenter contends that a wide range of studies have demonstrated that properly designed and operated combustion devices can easily achieve 98 percent control efficiency. For properly designed combustion devices, the commenter states that there is virtually no additional cost to move the control efficiency from 95 percent to 98 percent, yet the environmental benefit will be substantial. A 95 percent control efficiency will produce a 5 percent methane slip rate, more than double the slip rate for a 98 percent control efficiency. If EPA is concerned about the feasibility of requiring a 98 percent control efficiency for non-combustion control devices, the commenter recommends a separate efficiency standard be promulgated with a 98 percent control efficiency for combustion devices and a 95 percent control efficiency for non-combustion devices. The commenter suggests that a combustion device used for control of methane emissions should meet a minimum standard of 98 percent control efficiency.

Response I-5-35: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>78</sup>

### ***5.2.2 Control Technology Alternatives to Flaring***

Comment: Commenter (0594-Huntsman) views the use of methane pyrolysis as an effective flaring replacement in the long term. The commenter provides the following technology details.

Commenter (0594-Huntsman) informs that MIRALON® advanced carbon materials are produced from methane gas and potentially other hydrocarbons. The commenter's floating catalyst chemical vapor deposition (CVD) process, a form of methane pyrolysis, uses a reactor to break down the carbon in methane into a carbon nanomaterial while also creating a clean hydrogen fuel. During the pyrolysis, methane (for example, from flare gas), is pre-heated and introduced into a reactor where it is mixed with a combination of gases and a metal catalyst at high temperatures to isolate pure, solid carbon. To date, the process has achieved 80-90 percent single-pass efficiency converting methane into carbon and can achieve far higher conversion (99 percent +) with multiple passes. Projections show that transforming one small flare of 20 tons per day of natural gas into feedstock for this process over a ten-year period could avoid 230,000 tons of CO<sub>2e</sub> over a decade while only requiring 550 tons of CO<sub>2e</sub> to build based on construction materials. Assuming the energy comes from a portion of the hydrogen co-product, the commenter states that this delivers a 420x return on invested carbon.

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<sup>77</sup> 87 FR 74792 (December 6, 2022).

<sup>78</sup> 87 FR 74792 (December 6, 2022).

The commenter (0594-Huntsman) notes that reducing dependence on flares also reduces the potential for related performance problems and malfunctions. But methane pyrolysis also provides a practical means to improve performance and reduce the effect of malfunctions. The commenter contends that once methane pyrolysis is scaled and readily available, a well could switch between pyrolysis and flaring as needed – giving critical time to a facility to repair and/or improve flaring and eliminating any period where no controls are in place. The commenter’s eventual goal would be to take this one step further and for methane pyrolysis to be the dominant form of methane destruction, with flaring relegated to an emergency backup option.

Response I-5-36: EPA acknowledges the information provided by the commenter on an alternative technology to flaring. EPA does not specify a specific control technology that must be used to meet the requirements of the rule, but instead specifies a control standard. Owners/operators have the flexibility to choose the control device that would best meet their needs and meet the requirements of the rule, which is 95 percent reduction of VOC and methane emissions, for applicable affected facilities.

### ***5.2.3 Monitoring Requirements***

Comment: Commenter (0810- Petroleum Alliance-OK) recommends that EPA avoid burdensome or onerous monitoring requirements that dissuade operators from using combustion control devices that can attain a 95 percent destruction efficiency.

Commenter (0763-TCEQ) believes that existing monitoring and recordkeeping programs are sufficient to demonstrate compliance with destruction efficiency representation for control devices, and additional requirements will create regulatory and monitoring overlap and may also overlap or conflict with existing requirements.

Response I-5-37: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal related to combustion control devices.<sup>79</sup>

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<sup>79</sup> 87 FR 74792 (December 6, 2022).

## **Chapter 6. Environmental Justice (EJ) Implications and Stakeholder Outreach**

### **6.1 Environmental Justice and Impacts of Climate Change**

#### ***6.1.1 General Comments of Concern***

Comment: Several commenters (0276-Greater Boston Physicians for Social Responsibility (GBPSR), 0340-Mothers & Others for Clean Air (Mothers & Others), 0351-Department of Environmental Health Sciences, Mailman School of Public Health, Columbia University (Columbia), 0347-Columban Center for Advocacy and Outreach, Missionary Society of St. Columban (Columban), 0385-Silent Spring Institute (Silent Spring), 0402-Cancer Free Economy Network (Cancer Free), 0585-Kentucky Oil and Gas Association (KOGA), 0733-Conservation Voters New Mexico (CVNM), 0734-American Thoracic Society (ATS), 0781-National Tribal Air Association (NTAA), 0783-CA Assemblymember Bloom *et al.*, 0800-State of Utah, Public Lands Policy Coordinating Office (Utah), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute Tribe), 0837-Clean Water Action (CWA) *et al.*, 0844-Environmental Defense Fund (EDF) *et al.*, 0920-WE ACT for Environmental Justice (WAEJ), 0941-350Silicon Valley, 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault Tribe), 0949-Liveable Arlington, 1271-National Religious Partnership For The Environment (NRPE), 1282-Earthworks, 1330-Catskill Mountainkeeper, 1337-Boston Catholic Climate Movement (BCCM), 1350-EOS at Federated Hermes (EOS), 1383-New Mexico Interfaith Power and Light (NMIPL), 1384-Louisiana Environmental Action Network (LEAN) and Lower Mississippi Riverkeeper (LMRK), 1388-Private Citizen) express concern regarding the health of populations living near oil and natural gas development. A sample of some of their specific comments follows.

Commenters (0605-Muscogee (Creek) Nation, 0781-NTAA) supports EPA's efforts at evaluating and achieving EJ. The commenter states that, not only is an EJ review required, but it is also a part of good government. The commenter reports that studies have shown that residents of EJ communities are more vulnerable to the impacts of pollution due to pre-existing health conditions that often are higher in these communities due to lack of access to adequate nutrition and health care. The commenter suggests that doing the work of reaching out to these communities and taking a hard look at how environmental policies will impact their health is a much smarter approach than trying to address adverse health outcomes later on, along with the distrust that will have built up in the community as they have watched their health decline even further.

Commenter (1388-Private Citizen) states that existing facilities negatively impact our climate and our health. The commenter emphasizes that persons, many of them in low income and EJ communities, living near industry facilities have suffered negative health impacts, and reduced property values as a result of continuing, and sometimes life-long exposure to industry pollutants.

Commenter (1383-NMIPL) states that frontline communities currently suffer from the health effects of pollution which in their region (NM and TX) are experienced disproportionately by the

most vulnerable and the young who are part of Native American, Latinx and lower income communities.

Commenter (1271-NRPE) states that the African American community is disproportionately impacted by air pollution because of historical and ongoing systemic racism, which has placed our communities adjacent to polluting industries. With more than 1 million African Americans living within a half-mile of an existing natural gas facility, methane pollution leaves these communities exposed to toxic air pollution, with negative health impacts including cancer, reproductive and respiratory problems.

Commenter (0943-Sault Tribe) supports EPA's efforts at evaluating and achieving EJ. According to the commenter, studies have shown that residents of EJ communities are more vulnerable to the impacts of pollution due to pre-existing health conditions that often are higher in these communities due to lack of access to adequate nutrition and health care.

Commenter (0800-Utah) appreciates the acknowledgement of EJ, community involvement, and small business impacts because many of the oil and gas sources in Utah are in rural areas where the oil and gas industry has a large economic impact.

Commenter (0783-CA Assemblymember Bloom *et al.*) notes that California is the seventh-largest producer of crude oil in the nation and ranks third in oil refining capacity<sup>1</sup>, much of which occurs next to or within communities that are low income and inhabited primarily by people of color. As a result, the commenter states that oil extraction, refinement, and natural gas storage pose serious health threats to millions of Californians, including but not limited to those living in the predominantly black, indigenous, and people of color (BIPOC) communities of East Los Angeles, Richmond, and the Central Valley. Consequently, the commenter asserts that methane emissions represent not only environmental and health threats; they are an EJ crisis. The commenter also provides information on the adverse health effects from methane and volatile organic compound (VOC) emissions [see pages 1 and 2 of the commenters' letter].

Commenter (0920-WAEJ) contends that low-income communities, communities of color and tribal nations, especially in energy producing states, have been treated as sacrifice zones by this sector. The commenter suggests that frontline communities not only bear the brunt of the impacts of the climate crisis but they are disproportionately exposed to the harmful pollution and health and safety risks of oil and gas development as a result of decades of discriminatory zoning practices. The commenter adds that the industry is also a significant source of smog-causing VOCs and air toxics like benzene, formaldehyde, and ethylbenzene, which are emitted alongside methane. Numerous studies show that low-income, Indigenous, Black, and Hispanic people who live in close proximity to oil and gas development and operations are adversely affected by a

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<sup>1</sup> U.S. Energy Information Administration: California State Energy Profile, <https://www.eia.gov/state/print.php?sid=CA>.

range of negative health impacts, from migraines, depression, asthma attacks, irreversible lung damage, cardiovascular disease to cancer, preterm births, and premature deaths.<sup>2,3,4,5,6</sup>

Commenter (0734-ATS) states that a disproportionate amount of methane emissions come from a relatively small number of facilities, sometimes termed “super-emitters.” The commenter notes that, in California, each 10 percent increase in census block group proportion of Black residents is associated with a 10 percent increased odds of exposure to methane “super-emitter” facilities. The commenter adds that, across Colorado, Oklahoma, Pennsylvania, and Texas, minoritized communities, especially those with predominately Black residents, are much more likely to be close to oil and natural gas fracking wells. Furthermore, the commenter reports that low-income residents in Pennsylvania are disproportionately exposed to harmful air toxins and pollutants released from fracking operations.

Commenter (0402-Cancer Free) expresses specific concern with rising cancer rates—and a growing body of research points to chemicals in our environment as important, and preventable, risk factors for cancer.<sup>7</sup> The commenter notes that a legacy of oppression and systemic racism have led to a pattern of BIPOC populations disproportionately exposed to hazardous pollution,<sup>8</sup> including air pollution,<sup>9</sup> in tandem with a propensity to be more affected by climate change impacts.<sup>10</sup>

Commenters (0351-Columbia) assert that reducing methane and co-pollutant emissions from oil and gas wells could immediately improve public health and environmental justice concerns nearby and also slow long-term climate change that threatens our species.

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<sup>2</sup> Fann et al, Assessing Human Health PM2.5 and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025, *Environ. Sci. Technol.* 2018, 52, 15, 8095–8103 (2018), <https://doi.org/10.1021/acs.est.8b02050>.

<sup>3</sup> EDF, Populations impacted by oil and gas methane pollution in the United States (2019), <https://www.edf.org/federalmethanemap/USmethanefactsheet.pdf>.

<sup>4</sup> Casey et al, Unconventional natural gas development and adverse birth outcomes in Pennsylvania: The potential mediating role of antenatal anxiety and depression, *Environ Res* 177:108598 (2019), doi:10.1016/j.envres.2019.108598.

<sup>5</sup> Casey et al, Climate Justice and California’s Methane Superemitters: Environmental Equity Assessment of Community Proximity and Exposure Intensity, *Environ Sci Technol.* 55 (21): 14746-14757, doi:10.1021/acs.est.1c04328.

<sup>6</sup> Greenpeace, Fossil Fuel Racism: How Phasing Out Oil, Gas, and Coal Can Protect Communities (2021), <https://www.greenpeace.org/usa/wp-content/uploads/2021/04/Fossil-Fuel-Racism.pdf>.

<sup>7</sup> Cohen, L., & Jefferies, A. (2019). Environmental exposures and cancer: using the precautionary principle. *Ecancermedicalscience*, 13, ed91. doi: 10.3332/ecancer.2019.ed91.

<sup>8</sup> Bell J. (2016). 5 Things to Know About Communities of Color and Environmental Justice. Center for American Progress. <https://www.americanprogress.org/article/5-things-to-know-about-communities-of-color-andenvironmental-justice/>.

<sup>9</sup> Miranda, M. L., Edwards, S. E., Keating, M. H., & Paul, C. J. (2011). Making the Environmental Justice Grade: The Relative Burden of Air Pollution Exposure in the United States. *International Journal of Environmental Research and Public Health*, 8(6), 1755-1771. Retrieved from <https://www.mdpi.com/1660-4601/8/6/1755>. [5] NAACP. (2021). Environmental and Climate Justice. Accessed December 15th.

<https://naacp.org/knowissues/environmental-climate-justice>.

<sup>10</sup> NAACP. (2021). Environmental and Climate Justice. Accessed December 15th. <https://naacp.org/knowissues/environmental-climate-justice>.

Commenter (1282-Earthworks) states that the Oil and Gas Threat Map shows 12.6 million people living within a half mile radius of oil and gas extraction, processing or compressor stations. That includes 2.9 million at risk students in 9,000 schools suffering 750,000 asthma attacks and 500,000 lost school days per year. The commenter adds that numerous peer-reviewed scientific studies have documented elevated levels of harmful air pollutants in and around areas with oil and gas production activity and have shown that oil and gas facilities are the source of the excess pollution. Research that specifically deals with health indicates correlations between risks and/or prevalence of disease and proximity to facilities. The commenter notes that the half mile “threat radius” was chosen because it is a very conservative estimate of the area within which elevated levels of toxic pollution are seen, and the distance within which health impacts have most clearly been correlated with the presence of oil and gas facilities. The commenter states that the T Variables include total population, race and ethnicity, number of children, number of schools, and student enrollment.

Commenters (0837-CWA *et al.*, 1330-Catskill Mountainkeeper) state that over 12.5 million Americans live within half a mile of oil and gas operations. In California, commenter (0837-CWA *et al.*) notes that the number is over two million. According to the commenter, that is two million predominantly low-income people of color that have an elevated risk of cancer, asthma, respiratory, pulmonary and cardiovascular diseases, and an increased risk of negative birth outcomes like low-birth weight pregnancies, preterm birth and other birth related problems.

Similarly, commenter (0941-350 Silicon Valley) states that over 12.4 million Americans live within a half mile of an oil or gas well, gas compressor or gas processor.<sup>11</sup> Minorities are disproportionately represented in this group which has experienced an elevated incidence of cancer, asthma, pulmonary and cardiovascular diseases.<sup>12</sup> Also, pregnant women living in oil and gas producing regions face an increased risk of premature birth.<sup>13</sup>

Commenter (0788-350 Seattle) reports that over 12.4 million Americans live within half a mile of oil and gas operations, are disproportionately of color, and are likely to experience serious health effects from fossil fuel pollution. These health effects include an elevated risk of cancer, asthma, respiratory, pulmonary and cardiovascular diseases. In addition, the commenter notes that pregnant women living in oil and gas producing regions face an increased risk of premature birth, according to this study from 2020. The commenter adds that the EPA’s own research has estimated nearly 2,000 extra deaths each year will be caused by air pollution exposures from the oil and gas sector in 2025 and each year thereafter.

Several commenters (0557-Union for Reform Judaism (URJ), 0789-Pennsylvania Department of Environmental Protection (PA DEP), 0941-350 Silicon Valley) express specific concerns regarding climate change and impacts on vulnerable communities.

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<sup>11</sup> Alan Septoff, “Over 12 Million Americans Live in the Oil and Gas Threat Zone”, Earthworks, June 17, 2016.

<sup>12</sup> Lara J. Cushing et al., “Up in Smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US”, Environmental Research Letters, vol 16, n0 3, 2021.

<sup>13</sup> Lara J. Cushing et al., “Flaring from unconventional oil and gas development and birth outcomes in the Eagle Ford Shale in South Texas”, Environmental Health Perspectives, July 15, 2020.

Commenters (0557-URJ) express specific concern regarding the climate crisis as an ever-worsening tragedy, causing rising sea levels, global temperature extremes, and increases in severe weather, wildfires, and droughts. The commenter notes that climate impacts are detrimental to human health and wellbeing, particularly and disproportionately felt by vulnerable Communities of Color.

Commenter (0789-PA DEP) states that one of the most notable findings from their 2021 Pennsylvania Climate Impacts Assessment is that climate change will not affect all Pennsylvanians equally. The commenter reports that some may be more at risk because of their location, income, housing, health, or other factors.

Commenter (0941-350 Silicon Valley) suggests that, in addition to methane's effects on climate, EPA must also address the climate justice aspects of methane pollution.

Response I-6-1: EPA acknowledges the commenters' support for EPA's efforts to evaluate and address environmental justice in the November 2021 Proposal. Additionally, EPA has considered the information provided by the commenters regarding the impact of methane, VOC, and other air pollutant emissions from the oil and natural gas industry on the health of nearby populations, as well as other vulnerable communities, and finds that it is consistent with the approach that EPA has taken in the final rule.

### ***6.1.2 Native American Environmental Justice Impacts***

Comment: Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0833-Ute Tribe) express concern regarding the carve out of regulatory exceptions for Alaska. The commenters note that, although they recognize that the winter conditions in Alaska provide additional challenges, they are concerned that Alaska Native Villagers are not being protected equally or sufficiently. The commenters encourage the EPA to explore or research options that can be used in cold conditions that could provide more consistent protections for the fragile ecosystems and public health in Alaska.

Response I-6-2: The conditions in the Alaskan North Slope provide unique challenges for owners and operators in the oil and natural gas industry. As a result, EPA has determined that the best system of emission reduction (BSER) for certain affected and designated facilities in the oil and natural gas source category is different for sources located in the Alaskan North Slope and the rest of country. For example, EPA is finalizing the fugitive emissions standards at well sites and compressor stations on the Alaska North Slope to be annual OGI monitoring with the first attempt at repair within 30 days of finding fugitive emissions and the final repair within 30 days of first attempt. There would also be an option to use annual EPA Method 21 monitoring with 500 ppm defined as a leak instead of OGI monitoring. Owners and operators on the Alaska North Slope would also have the option to use the alternative period screening with advance measurement technology approach or monitoring and repair based on using a continuous monitoring system instead of OGI monitoring. EPA explained the rationale in the November 2021 Proposal<sup>14</sup> and additional explanation in the December 2022 Supplemental Proposal.<sup>15</sup> See

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<sup>14</sup> 86 FR 63163 and 86 FR 63174-63175.

<sup>15</sup> 87 FR 74740.

40 CFR 60.5397b and 40 CFR 60.5397c for final requirements for fugitive emissions components. Another example, EPA is finalizing a standard of 6 scfm for continuous bleed pneumatic controllers in Alaska at sites where onsite power is not available and a standard of OGI monitoring and repair of emissions from intermittent natural gas driven pneumatic controllers. EPA explained the rationale in the November 2021 Proposal<sup>16</sup> and did not propose any changes in the December 2022 Supplemental Proposal. See 40 CFR 60.5390b and 40 CFR 60.5394c for final requirements for process controllers. Where possible, EPA is finalizing the same BSEER for affected sources located in the Alaskan North Slope as the rest of the country. Some examples of this include the requirements for well completions, storage vessels, and associated gas. Additionally, see the final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenters (0578-Grand Canyon Trust (GCT), 0781-NTAA) express that climate change and oil and natural gas operations disproportionately impact near source low wealth, minority communities, particularly Tribal communities.

Commenters (0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-Ute Tribe, 0943-Sault Tribe) states that, while EJ concerns may apply to many Tribal communities, there also needs to be recognition that Tribes are very distinct entities that preexist establishment of the United States. The commenters assert that Tribes possess authority that predates the U.S. Constitution regarding the governance of their own internal affairs. For these reasons, the commenters state that EJ is an important issue, but must never usurp Tribal sovereignty and self-determination. Further, the commenters argue that EJ must never replace government-to-government consultation directly with Tribes. They add that, any EJ actions must treat Tribes as sovereign nations with self-determination first and part of the EJ community second. The commenters suggest that the EPA's baseline assessment to determine if EJ concerns exist is not sufficient analysis with respect to considering and addressing Tribal impacts.

Commenter (0788-350 Seattle) states that the EPA's baseline assessment to determine if EJ concerns exist is not sufficient analysis with respect to considering and addressing Tribal impacts.

Commenter (0578-GCT) reports that a report by the Clean Air Task Force states that residents of the Navajo Nation are two times more likely to live within a half mile of an oil and gas facility compared to Utah and New Mexico.<sup>17</sup> The commenter adds that it also highlights that residents of Northern Ute Lands in the Uinta Basin, Utah are 42 times more likely to live within a half mile of an oil and gas facility. Proximity to oil and gas facilities also indicates exposure to methane pollution, hazardous air pollutants (HAPs), and VOCs. Historically, the commenter

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<sup>16</sup> 86 FR 63207- 63209.

<sup>17</sup> Clean Air Task Force. Tribal Communities at Risk: The Disproportionate Impacts of Oil and Gas Air Pollution on Tribal Air Quality. Available at: [https://cdn.catf.us/wpcontent/uploads/2018/05/21094517/Tribal\\_Communities\\_At\\_Risk.pdf](https://cdn.catf.us/wpcontent/uploads/2018/05/21094517/Tribal_Communities_At_Risk.pdf). At 3.



states Tribes have a complex history in relation to oil and gas development in that they depend on coal and gas for revenue and jobs but have also supported conservation, public health and cultural preservation measures. According to the commenter, however, the relationship between the federal government, industry and Tribes has been fraught with exploitation and injustice<sup>18</sup> with Tribal communities not being fully compensated for their investment and shouldering the environmental costs and public health burden.<sup>19</sup>

Commenter (0794-Mandan, Hidatsa and Arikara Nation (MHA Nation)) asserts that, in upholding its trust responsibility EPA must consider the viewpoints of Tribes committed to pursuing responsible oil and gas development. The commenter is concerned that the Oil and Gas Methane Regulations as proposed would unreasonably burden development of tribal energy resources. The commenters state that the EPA has committed to upholding its trust responsibility by "protect[ing] the environmental interests of Indian Tribes when carrying out its responsibilities that may affect the reservations."<sup>20</sup> The commenter adds that EPA's trust responsibility also requires it to protect the right of tribes to develop their trust resources. Indeed, the commenter states that the federal government's "trust responsibility consists of the highest moral obligations that the United States must meet to ensure the protection of tribal and individual Indian lands, assets, resources, and treaty and similarly recognized rights."<sup>21</sup>

Commenter (0794-MHA Nation) notes that, in reaffirming the agency's Indian Policy in September 2021, EPA Administrator Michael S. Regan expressly "recognize[d] the right of tribes as sovereign governments to self-determination and acknowledge[d] the federal government's trust responsibility to tribes."<sup>22</sup> The commenters recommend that EPA engage with tribes on a government-to-government basis and consider the interests of tribes, like the MHA Nation, that are committed to implementing policies that both adequately protect the environment and allow for continued oil and gas development. According to the commenter, this is especially true in cases such as this when a proposed EPA regulation threatens the development of the MHA Nation's tribal trust assets. The commenter suggests that, in managing tribal trust assets, the federal government has an obligation to "[p]romote tribal control and self-determination over tribal trust lands and resources."<sup>23</sup> Lastly, the commenters assert that, in

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<sup>18</sup> Native American Rights Fund webpage. Individual Indian Money Accounts- Cobell V. Salazar. Available at: <https://www.narf.org/cases/cobell/>.

<sup>19</sup> Ute Indian Tribe Business Committee Department. Ute Indian Tribe Develops Strategic Plan for Oil & Gas Development. Available at:

<http://www.utetribes.com/images/Departments/BusinessCommittee/OilGasDevelopmentPlan12-23-20.pdf>.

<sup>20</sup> U.S. Environmental Protection Agency, EPA Policy for the Administration of Environmental Programs on Indian Reservations, (Nov. 8, 1984), <https://www.epa.gov/sites/default/files/2015-04/documents/indian-policy-84.pdf>.

<sup>21</sup> The U.S. Department of the Interior, Secretarial Order No. 3335, Reaffirmation of the Federal Trust Responsibility to Federally Recognized Tribes and Individual Indian Beneficiaries (Aug. 20, 2014), [https://www.doi.gov/sites/doi.gov/files/elips/documents/3335reaffirmation\\_of\\_federal\\_trust\\_responsibility\\_to\\_federally\\_recognized\\_indian\\_tribes\\_and\\_individual\\_indian\\_beneficiaries.pdf](https://www.doi.gov/sites/doi.gov/files/elips/documents/3335reaffirmation_of_federal_trust_responsibility_to_federally_recognized_indian_tribes_and_individual_indian_beneficiaries.pdf).

<sup>22</sup> U.S. Environmental Protection Agency, Memorandum from EPA Administrator Michael S. Regan, to all EPA Employees, regarding "Reaffirmation of the U.S. Environmental Protection Agency's Indian Policy" (Sept. 30, 2021), <https://www.epa.gov/system/files/documents/2021-09/oita-21-000-6427.pdf>.

<sup>23</sup> U.S. Department of the Interior, Departmental Manual, part 303, ch. 2: Principles for Managing Indian Trust Assets (Oct. 31, 2000), <https://www.doi.gov/sites/doi.gov/files/elips/documents/303-dm-2.pdf>; see also U.S. Department of the Interior, Bureau of Trust Fund Administration, Trust Principles, <https://www.doi.gov/ost/about-us/Trust> (last visited Jan. 28, 2022).

developing its proposed Oil and Gas Methane Regulations EPA did not adequately consider how tribes that have embraced oil and gas development would be impacted.

Commenter (0844-EDF *et al.*) states that, as EPA notes in its environmental justice analysis, Native American populations on average may be exposed to a higher concentration of ozone from oil and natural gas VOC emissions than white populations.<sup>24</sup> The commenter reports that Native Americans who are part of the Navajo Nation in Utah and New Mexico and the Fort Berthold Indian Reservation are two times more likely to live within a half mile of an oil and gas facility compared to individuals in encompassing states, and those in Uintah-Ouray (Northern Ute) are 42 times more likely to be within a half mile than individuals in encompassing states.<sup>25</sup>

Response I-6-3: EPA recognizes the status and rights of Tribal Nations, as sovereign governments, to self-determination and acknowledges the federal government's trust responsibility to Tribes. EPA provides programs, resources, financial assistance, technical assistance and training, consultation opportunities and dedicated engagement to help identify and mitigate perceived and tangible implications to Tribes.

On November 16, 2021, EPA sent a letter to all 574 Federally Recognized Tribes inviting Tribes to participate in Tribal Consultation on the November 2021 Proposal. Three Tribes (MHA Nation, the Northern Arapaho Tribe, and the Eastern Shoshone Tribe) requested consultation and those consultations were held on January 24, 2022, January 24, 2022, and January 25, 2022, respectively. On November 14, 2022, EPA sent an additional letter to all 574 Federally Recognized Tribes inviting Tribes to participate in a Tribal Consultation on the December 2022 Supplemental Proposal. EPA held Tribal Consultation with MHA Nation on January 24, 2023. On February 24, 2023, EPA held an informational meeting with the Ute Tribe.

EPA recognizes that some implications may be felt disproportionately across Indian country as well as in communities. EPA's EJ analyses focused on a baseline distribution of emissions from oil and natural gas sources, enabling the Agency to characterize risks due to oil and natural gas emissions prior to implementation of the rule. While the EPA agrees that baseline assessment alone is not the optimal approach for determining if EJ concerns exist with respect to considering and addressing Tribal impacts, it was the only analytic approach feasible when preparing the November 2021 Proposal and December 2022 Supplemental Proposal RIAs.

With respect to considering how the rule would impact tribal trust assets, EPA considered how tribes that have embraced oil and gas development would be impacted by this rulemaking through consideration of the impacts of potential regulation on employment among overburdened or marginalized communities. The RIA notes that a reduction in employment in the oil and natural gas sector may be associated with loss of income for workers in the oil and gas industry, and for oil and gas communities.

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<sup>24</sup> RIA 4-18.

<sup>25</sup> Clean Air Task Force, Tribal Communities at Risk: The Disproportionate Impacts of Oil and Gas Air Pollution on Tribal Air Quality (2018) 3.

### 6.1.3 Conducted EJ Analyses

Comment: Several commenters (0351-Columbia, 0385-Silent Spring, 0573-Kansas Department of Health and Environment (KDHE), 0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ), 0844-EDF *et al.*, 0949-Liveable Arlington) cite several EJ analyses conducted that specifically looked at EJ in the context of oil and natural gas operations. Examples of some of these comments are provided below.

Commenter (0351-Columbia) reports that their studies have used spatial methods and electronic health record data on thousands of individuals where they could control for both individual and area-level factors (Casey *et al.* 2016, Casey *et al.* 2018, Casey *et al.* 2019, Tustin *et al.* 2017, Rasmussen *et al.* 2016). As a result of these studies, they report that they have found relationships between living closer to more wells and more actively producing wells and increased risk of preterm birth, migraine headache, depression, and cardiovascular disease in Pennsylvania. In studies in California with Dr. Rachel Morello-Frosch they have also used statewide birth certificate data and found that living within 1 km of an oil or gas well was associated with increased odds of low birth weight, small for gestational age birth, and decreased term birth weight among individuals living in rural areas (Tran *et al.* 2020). The commenter also notes that a study in Texas found an increased risk of preterm birth among women exposed to gas flaring (Cushing *et al.* 2020). The commenter adds that, in California, there have been recent studies that found evidence that people of color are more likely to live closer to methane super-emitters, suggesting that reducing emissions from oil and gas wells is also an issue of environmental justice (Casey *et al.* 2021).

Commenter (0844-EDF *et al.*) reports that, in Texas there are over 800,000 Latinos living within half a mile of an oil or gas well, in Colorado nearly 3 out of 10 people living near a well are Latino, and in California 2 out of 5 people living near a well are Latino.<sup>26</sup> In the U.S. overall, more than 1.81 million Latinos live within a half mile of existing oil and gas facilities and more than 1 million African Americans live within a half mile of existing natural gas facilities.<sup>27</sup> The commenter notes that a recent study of almost 61 million Medicare patients conducted nationwide indicates a strong association between exposure to harmful pollutants associated with oil and gas facilities and mortality for minorities.<sup>28</sup> The commenter provides specific disproportionate air pollution exposure burdens for differing minority populations (*e.g.*, African Americans, Latinos, Native Americans).

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<sup>26</sup> Latino Communities at Risk: The Impact of Air Pollution from the Oil and Gas Industry, Clean Air Task Force (CATF), League of United Latin American Citizens (LULAC), National Hispanic Medical Association (NHMA) 2016.

<sup>27</sup> Clean Air Task Force, Latino Communities at Risk: The Impact of Air Pollution from the Oil and Gas Industry (2016) (“CATF Latino Communities”) at 2; Clean Air Task Force, Fumes Across the Fence-Line: The Health Impacts of Air Pollution from Oil & Gas Facilities on African American Communities (2017) (“CATF African American Communities”) at 4.

<sup>28</sup> Di *et al.*, Air Pollution and Mortality in the Medicare Population, NEW ENGLAND J. OF MEDICINE (June 29, 2017); Di Q, Dai L, Wang Y, Zanobetti A, Choirat C, Schwartz JD, Dominici F, Association of short-term exposure to air pollution with mortality in older adults, JAMA (Dec. 26, 2017); 318(24):2446-56.

Commenter (0385-Silent Spring) notes that it is well-documented that oil and gas wells and other operations are disproportionately located in communities of color. In EPA's own criteria air pollutant (CAP) EJ analysis, the commenter notes that it was demonstrated that both Native American and Hispanic populations experience higher exposure of ozone as a result of VOC emissions from oil and gas sources when compared to the general population.<sup>29</sup> Meanwhile, in California, the commenter reports that there are 5.4 million people who live within 1 mile of an existing oil and gas well, and 1.8 million of this 5.4 million (33 percent) also live in, as identified by California EPA's tool CalEnviroscreen 2.0, areas most burdened by environmental pollution.<sup>30</sup> Most notably, the commenter notes that 92 percent of the 1.8 million people living in these areas most disparately exposed to pollution are people of color.<sup>31</sup> The commenter adds that research has also displayed that census tracts in Pennsylvania exposed to pollution from gas wells have a significantly higher percent of residents below the poverty line when compared to census tracts not exposed to gas well pollution.<sup>32</sup> Meanwhile, the commenter states that an analysis of the Eagle Ford shale in Texas displays that even though white, non-Hispanic residents are more likely to live in the vicinity of oil and gas wells, primarily (80 percent) Hispanic census blocks are exposed to twice as many gas flares within 5 km as compared to primarily white, non-Hispanic census blocks.<sup>33</sup>

Commenter (0949-Liveable Arlington) reports that "[m]ore than 30,000 Arlington children go to public school within half a mile of wells, according to an analysis by Reveal from The Center for Investigative Reporting, and up to 7,600 infants and young children attend private daycares within that radius. Eighty-five percent of the public school students are children of color, and more than two-thirds live in poverty. Altogether, more than half of Arlington's public schools and day care facilities are within a half-mile of active gas production. Eight day care centers are within 600 feet, the standard setback in Arlington."<sup>34</sup>

Commenter (0573-KDHE) conducted an analysis (using EJSCREEN tool) of Kansas county populations impacted at an environmental justice index of greater or equal to 90th percentile for the air toxics cancer and air toxics respiratory fields. Using the option of comparing Kansas counties with U.S. counties as a whole, the commenter found that five Kansas counties had cancer or respiratory impacts. The commenter then ranked oil and gas production on a county basis for 2020 and compared rankings with the five greater or equal to 90th percentile

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<sup>29</sup> U.S. Environmental Protection Agency. (2020). Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Office of Air Quality Planning and Standards Health and Environmental Impacts Division. [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf).

<sup>30</sup> National Resources Defense Council. (2014). Drilling in California: Who's at risk? Los Angeles, CA: Natural Resources Defense Council (NRDC). <https://www.nrdc.org/sites/default/files/california-fracking-risks-report.pdf>.

<sup>31</sup> Bell, M. L., & Ebisu, K. (2012). Environmental inequality in exposures to airborne particulate matter components in the United States. *Environmental health perspectives*, 120(12), 1699–1704. doi: 10.1289/ehp.1205201.

<sup>32</sup> Ogneva-Himmelberger, Y., & Huang, L. (2015). Spatial distribution of unconventional gas wells and human populations in the Marcellus Shale in the United States: Vulnerability analysis. *Applied Geography*, 60, 165-174. doi: 10.1016/j.apgeog.2015.03.011.

<sup>33</sup> Johnston, J. E., Chau, K., Franklin, M., & Cushing, L. (2020). Environmental Justice Dimensions of Oil and Gas Flaring in South Texas: Disproportionate Exposure among Hispanic communities. *Environmental Science & Technology*, 54(10), 6289-6298. doi: 10.1021/acs.est.0c0041.

<sup>34</sup> Investigation by Reveal for Public Radio International.

counties found in EJSCREEN. Results for oil-producing counties turned up three counties, with the highest ranking of these counties ranking 76th among 90 oil producing counties in the state, with 26,800 bbl annual production. The commenter notes that average Kansas county oil production is 314,000 bbl. Results for natural gas-producing counties showed one impacted county with any gas production, with this county ranking 47th among 49 natural gas-producing counties in the state, with 0.016 MMcf annual production. The commenter notes that average Kansas county natural gas production is 3,351 MMcf. According to the commenter, their analysis did not find a significant correlation between oil or gas production and negative health outcomes on a county basis.

Commenter (0727-OSEE/ODEQ) reports that a study by Price Waterhouse for the American Petroleum Institute determined that the oil and gas sector was responsible (including direct and indirect employment) for 16.7 percent of the Oklahoma workforce.<sup>35</sup> The commenter adds that many oil and gas jobs employ residents of rural communities.<sup>36</sup> To assess the possible impacts of job losses in those communities, work performed by the U.S. Department of Agriculture's (USDA's) Economic Research Service investigated economic, social, and demographic factors that affect the poverty status of residents of rural communities. For 2019, the commenter reports that the USDA estimated Oklahoma's statewide poverty rate at 15.1 percent with 19.7 percent of Oklahoma's children living in poverty.<sup>37</sup> The commenter states that rural counties, especially in the southeastern part of the state are particularly impacted by poverty. The availability of middle class oil and gas jobs in rural Oklahoma mitigates the poverty experienced in many of these communities. The commenter requests that, to ensure that just policies are adopted, EPA weigh the economic impacts on vulnerable communities, especially rural communities, as carefully as the environmental benefits are evaluated.

Response I-6-4: EPA acknowledges the information provided by commenters to support EPA's efforts to evaluate and address environmental justice in the November 2021 Proposal. As described in the 2021 RIA, EPA is aware of all studies identified in the bibliography of peer-reviewed studies published since 2015 provided by the Health Effects Institute that evaluate populations that may be disproportionately impacted by the oil and natural gas industry. However, there is considerable discordance among study results. For example, studies differ with regards to geographic area, population of interest, and health outcome. For those reasons, EPA instead relies on associations between exposure and health effects from standardized documents, such as integrated science assessments.

In response to comments regarding the percent of Oklahoma's workforce that is directly or indirectly employed by the oil and gas sector, EPA notes impacts of the proposed regulation on employment among overburdened or marginalized communities was considered in section 4.2.5

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<sup>35</sup> "Impacts of the Oil and Natural Gas Industry on the US Economy in 2019," prepared by PricewaterhouseCoopers LLP, prepared for the American Petroleum Institute, July 2021, available on-line: <https://www.api.org/-/media/Files/Policy/American-Energy/PwC/API-PWC-Economic-Impact-Report.pdf>.

<sup>36</sup> See, for example, the article "Feeling the Pain: In Rural Oklahoma, Oilfield Communities See the Ups and Downs of Oil and Gas Industry Firsthand," by Heidi Brandes, February 11, 2021, available on-line on the web page of The Petroleum Alliance: <https://www.thepetroleumalliance.com/feeling-the-pain-in-rural-oklahoma-oilfield-communities-see-the-ups-and-downs-of-oil-and-gas-industry-first-hand/>.

<sup>37</sup> U.S. Department of Agriculture, Economic Research Service, Rural Poverty & Well-Being, state poverty rate data available on-line: <https://data.ers.usda.gov/reports.aspx?ID=17826>.

of the RIA. The RIA notes that a reduction in employment in the oil and natural gas sector may be associated with loss of income for workers in the oil and gas industry, and for oil and gas communities. EPA disagrees it did not weigh the economic impacts on vulnerable communities, especially rural communities, as carefully as the environmental benefits.

## 6.2 Environmental Justice Implications

### 6.2.1 Control of Emissions is Needed to Reduce EJ and Climate Impacts

Comment: Several commenters (0340-Mothers & Others, 0347-Columban, 0398-Representative Barragan *et al.*, 0402-Cancer Free, 0605-Muscogee (Creek) Nation, 0761-Exelon Corporation (Exelon), 0788-350Seattle, 0791-Airdar Inc. (Airdar), 0800-Utah, 0807-BP America, Inc. (BP), 0941-350 Silicon Valley, 1337-BCCM) support control of emissions from oil and gas operation to reduce EJ and climate impacts. Below are examples of these comments.

Commenter (0347-Columban) strongly supports the November 2021 Proposal; however, the commenter urges EPA to set stronger standards. The commenter contends that, in the United States, strict methane rules are urgently needed to protect the health of many communities, especially minority communities, Latino, African American and Indigenous communities. The commenter states that the United States and EPA must ensure we meet our international commitments and obligations. The commenter requests that EPA strengthen the November 2021 Proposal to address climate change and protect the public health of vulnerable communities through supplemental rulemaking or other action, in order to:

1. End the wasteful and dangerous practice of routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already.
2. Require regular monitoring at all smaller, high-polluting, and leak-prone wells,
3. Work to incorporate emission monitoring results generated by community groups and other third parties into its standards.
4. Continuously engage with front-line community workers and other community-based organization as we believe community participation is critical to address gaps and measure success.
5. Lastly, the commenter urges EPA to finalize this rulemaking as quickly as possible. Our planet is in a climate crisis. The lives of many in the United States and abroad are already in danger.

Commenter (0398-Representative Barragan *et al.*) suggests that there is a need to expand the rule to address the control of emissions from smaller leak prone wells and the wasteful practice of flaring to ensure the protection of frontline communities that are often communities of color and low-income communities from pollution. The commenter added that flaring studies have shown that Latino, Black, and indigenous communities are disproportionately exposed to flaring and its associated health risks,<sup>38</sup> including the development and exacerbation of asthma, cardiopulmonary problems, and cardiovascular mortality. The commenter emphasized the need

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<sup>38</sup> <https://news.usc.edu/183286/americans-oil-gas-flaring-health-risks-usc-research/>.

to control methane and health harming co-pollutants, including VOCs and toxic and hazardous chemicals like benzene.

Commenter (0340-Mothers & Others) expresses that the proposed methane rule will help address climate change by reducing one of the most potent greenhouse gases that exists. However, the commenters suggest that it needs to be stronger. The commenter states that we have the tools and technology to meet stronger standards, because some states already have strong standards. The commenter recommends that EPA eliminate venting and flaring, close loopholes, and inspect ALL wells for leaks. The commenter reports that children living near gas wells are just as vulnerable to the health effects of methane and associated VOCs no matter who or how large the company is that owns the well. According to the commenter, the EPA needs to respond to the scientists and health experts urging stronger standards and set standards without loopholes that are fully protective of human health.

Commenter (0807-BP) agrees that the steps EPA proposes to reduce methane emissions are not only important to addressing climate change, but they also have the potential to improve air quality and public health for communities that have experienced a cumulative exposure to pollution impacts over time, including communities with environmental justice concerns. See 86 Fed. Reg. 63,110, 63, 122 (Nov. 15, 2021) (“Under the proposed rule, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, [fine particles that have a diameter less than 2.5 micrometers] PM2.5, and [hazardous air pollutants] HAP.”).

Commenter (1337-BCCM) states that, by taking decisive action we can curb harmful emissions and cut health-harming local air pollution for over 9 million people who live near oil and gas operations across the U.S.

Commenter (0941-350 Silicon Valley) states that reducing methane emissions would have many co-benefits of the improved health of residents and workers in neighboring communities.

Commenter (0800-Utah) encourages EPA to continue to support flexibility with these rules to ensure balance with economics and protection of human health and the environment.

Commenter (0402-Cancer Free) states that air pollutants, as well as greenhouse gases emitted from oil and gas sources only serve to exacerbate climate and health inequities in parallel, and the proposed rules, if accepted, have great potential to mitigate both inequities.

Commenter (0761-Exelon) suggests that any final rule should include strong measures to protect disadvantaged and overburdened communities from disproportionate adverse public health and environmental effects of air pollution emitted from the new and existing sources that are addressed in the November 2021 Proposal.

Commenter (0605-Muscogee (Creek) Nation) encourages EPA to consider and compare the costs of the controls to the full range of negative costs experienced from the oil and natural gas industry's high methane, VOC, and HAP emissions.

Commenter (0791-Airdar) adds with issues around social justice and environmental, social, and governance (ESG) standards becoming increasingly important to society, allowing industry to use more advanced monitoring technologies will allow companies to better address these issues, be proactive, and reduce costs related to the consequences of not addressing these issues sooner.

Response I-6-5: EPA acknowledges the commenter's support for EPA's efforts to evaluate and address environmental justice concerns and climate impacts in the November 2021 Proposal. Additionally, EPA has considered the information provided by the commenters regarding the impact of methane, VOC, and other air pollutant emissions from the oil and natural gas industry on the health of nearby populations, as well as other vulnerable communities, and finds that it is consistent with the approach that EPA has taken in the final rule. See sections X and XI of the final preamble for a full discussion of the final standards.

Comment: Commenter (0808-American Petroleum Institute (API)) supports appropriate consideration and adequate protection of disadvantaged groups and that the EPA has made EJ a priority in developing the November 2021 Proposal. For example, the commenter notes that the EPA made extensive outreach to disadvantaged and potentially overburdened populations and proactively sought to address their concerns in the proposal. EPA also included provisions in the November 2021 Proposal that are at least partially designed to address EJ issues. For example, the commenter states that the EPA explains that it provided for the use of "cutting edge" technologies in the rule, "alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology." 86 Fed. Reg. at 63139. To address the concern of "addressing large emission sources faster," the commenter states that the EPA proposes "more frequent monitoring at sites with more emissions." *Id.* And in response to concerns about health impacts, "EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions." *Id.*

Commenter (0808-API) supports EPA's attention to potential EJ issues and agrees that the measures described above will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The commenter asserts that the natural gas and oil industry's top priorities are protecting the public health and safety – regardless of race, color, national origin or income – and the environment. The commenter notes that they strive to understand, discuss and appropriately address community concerns with our operations. The commenter added that they are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations that may be disproportionately impacted.

Response I-6-6: EPA acknowledges the commenter's support for EPA's efforts to evaluate and address environmental justice concerns in the November 2021 Proposal. EPA takes a consistent approach to this issue in the final rule.

Comment: Commenter (0783-CA Assemblymember Bloom *et al.*) asserts that, because methane emissions represent an environmental justice crisis, they recommend that EPA expand the proposed methane rule to ensure that smaller leak prone wells are covered with regular inspections under the rule, and it eliminates routine flaring. While the commenter states that the



EPA's proposed regulatory changes are promising, they do not believe they go far enough to curb the overall threats of methane and its co-pollutants, or address the unjust level of exposure experienced by communities of color. The commenter explains that, while it is easy to ignore smaller, leak-prone wells because they generate such a small proportion of usable product, the huge number of these facilities and their leakage makes them large emitters of methane, with particular concern in earthquake prone regions such as California.<sup>39</sup> Yet under EPA's November 2021 Proposal, the commenter notes that operators that calculate less than 3 tons of methane/year may avoid regular monitoring, resulting in significant environmental pollution. For this reason, they urge EPA to enact comprehensive requirements for frequent leak inspections, regardless of the size of the wells involved.

Response I-6-7: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions at well sites in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>40</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions at well sites.

### ***6.2.2 Title VI of the Civil Rights Act***

Comment: Commenter (0920-WAEJ) suggests that the EPA strengthen enforcement and interpret the methane standards through the lens of Title VI of the Civil Rights Act. The commenter states that the EPA's historical failure to effectively enforce Title VI perpetuates the troublesome trend of concentrating oil and gas facilities in environmental justice communities already overburdened by pollution and has led to chronic diseases or comorbidities in addition to increasing vulnerabilities to climate change impacts. The commenter adds that the Clean Air Act (CAA) standards are based on industrial standards of pollution and suggests that the EPA shift away from enforcement of the CAA as a stand-alone regulation but rather in conjunction with racially disproportionate burden. The commenter states that section 111(d) and Title VI should be viewed together and enforced in harmony to address existing and prevent future environmental harms to frontline communities by the fossil fuel industry, which we see as human and civil rights violations. The commenter contends that Title VI should not be subordinate to environmental laws.

Response I-6-8: The commenters appear to be advocating that the EPA improve enforcement of Title VI of the Civil Rights Act with respect to oil and gas facilities. This is not a comment on the proposed CAA section 111(d) standards themselves, and is therefore outside the scope of the rulemaking. EPA will take the commenters suggestions regarding enforcement under advisement.

### ***6.2.3 EPA's EJ Analysis***

Comment: Commenter (0727-OSEE/ODEQ) states that the RIA uses Public Use Microdata Area (PUMA) data to identify oil and gas communities. The commenter asserts that this level of

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<sup>39</sup> Mary Kang et al, 2019. Potential increase in oil and gas well leakage due to earthquakes, Environ. Res. Commun. 1 121004, <https://iopscience.iop.org/article/10.1088/2515-7620/ab576e>.

<sup>40</sup> 87 FR 74705; December 6, 2022.

analysis is insufficiently specific in identifying impacts on rural areas. This assertion, according to the commenter, is demonstrated by the map (Figure 4-9 on p. 4-36 of the RIA) which shows the relatively large size of each PUMA. In addition, the oil and gas PUMAs shown in the map cover more than half the state of Oklahoma. In contrast, the commenter notes that the environmental justice communities in EJScreen<sup>41</sup> are identified with much finer granularity. The commenter states that this raises the question: to what degree does this analysis inherently bias the evaluation of costs and benefits, possibly privileging certain communities compared to others?

Commenter (0727-OSEE/ODEQ) states that Table 4-9 in the RIA document provides demographic data for the entire group of PUMAs with high oil and gas intensity. This analysis is used to draw various conclusions concerning the ethnic make-up, educational attainment, and income of residents in these areas compared with other areas with lower oil and gas intensity. According to the commenter, by aggregating the high oil and gas PUMAs for these analyses, EPA fails to give a sufficiently granular analysis of the impacts of the types of rural communities found in Oklahoma. The commenter contends that this contrasts with EPA's approach in evaluating impacts on environmental justice communities. The commenter notes that, while the analysis in the RIA that follows (see Table 4-10 and Figure 4-10 of the RIA) provides some greater specificity, it is still insufficient and still fails to meet the standards EPA uses for evaluating EJ communities.

Response I-6-9: The commenters note that PUMAs cover large spatial area in rural settings, contrast that with the finer spatial scale used for distributional exposure analysis and suggest that EPA should use a finer spatial scale to analyze impacts on oil and gas communities. EPA believes that PUMAs are an appropriate scale to analyze impacts on oil and gas communities. Performing such an analysis at a small spatial unit such as the tract or 12 km grid cell would face data limitations and would limit EPA's ability to analyze economically important spillover effects on nearby tracts or grid cells.

Comment: Commenter (1267-California Office of the Attorney General (CA AG) *et al.*) suggests that EPA has significantly underestimated the EJ impacts associated with HAP emissions from the oil and natural gas sector, including the cumulative and long-term impacts on communities and workers exposed to the emissions from a disproportionate number of facilities continuously sited in already overburdened neighborhoods. First, the commenter states that the EPA has only considered the cancer-related risks on EJ communities;<sup>42</sup> however, according to EPA's own data, four of the eight most significant HAP pollutants from the oil and natural gas sector are not classified by EPA as carcinogenic.<sup>43</sup> These include toluene, ethylbenzene, mixed xylenes, and n-hexane. The commenter notes that exposure to these pollutants has other deleterious effects on human health. For example, the commenter states that chronic exposure to toluene can cause irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with

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<sup>41</sup> See <https://www.epa.gov/ejscreen>.

<sup>42</sup> RIA at 4-25 ("To evaluate the potential EJ impacts associated with baseline HAP emissions from the oil and gas sector, the EPA has assessed the cancer risks and estimated the demographic breakdown of people living in areas with potentially elevated risk levels.").

<sup>43</sup> Id. at 3-21.

sleep.<sup>44</sup> Similarly, the commenter notes that long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, fatigue, tremors, and impaired motor coordination.<sup>45</sup> The commenter adds that chronic exposure to n-hexane causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue.<sup>46</sup> According to the commenter, EPA's omission of these impacts from HAP exposure in its consideration of the EJ impacts of the oil and natural gas sector results in an analysis that does not reflect the full toxic burden imposed. The commenter recommends that EPA revise its analysis to account for and recognize these non-cancer impacts.

Response I-6-10: EPA did not assess noncancer hazards for toluene, ethylbenzene, mixed xylenes, and hexane for this RIA. Based on the air toxics concentrations modeled in the cancer risk assessment, the non-cancer hazard from these HAP would be expected to be well below health-protective values.

Comment: Commenter (0842-Institute for Policy Integrity at NYU School of Law (NYU)) requests that EPA expand its distributional analysis beyond baseline conditions to evaluate the impacts of the November 2021 Proposal and alternatives. The commenter explains that the EPA conducts an extensive distributional analysis in the November 2021 Proposal's accompanying RIA that qualitatively and quantitatively identifies disparities in the populations exposed to emissions from the oil and gas source category.<sup>47</sup> However, the commenter suggest that this analysis fails to capture the distributional impacts of the November 2021 Proposal. Instead, they state that the analysis evaluates only the current baseline emissions emitted from the source category and concludes without support that communities experiencing disproportionate impacts in the baseline scenario "may realize disproportionate improvements in air quality resulting from emissions reductions."<sup>48</sup> The commenter argues that the EPA cannot reasonably conclude that disadvantaged communities will see disproportionate improvements without analyzing the impacts of the November 2021 Proposal on baseline conditions.

According to the commenter (0842-NYU), the EPA's analysis, while thorough, fails to evaluate the distributional impact of the November 2021 Proposal itself. They suggest that a baseline understanding of disproportionate burdens created by the source category is helpful but must be accompanied by an analysis that evaluates the distribution of impacts resulting from the November 2021 Proposal and any marginal differences from adopting EPA's proposed alternatives. Indeed, they state that President Biden's Memorandum on Modernizing Regulatory Review calls for analysis that reveals rules' "distributional consequences . . . to ensure that regulatory initiatives appropriately benefit and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities."<sup>49</sup> And evaluation of alternatives is crucial to a meaningful analysis to avoid an agency merely concluding the distributional impacts of its regulatory approach are acceptable without knowing whether the distributional impacts of an

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<sup>44</sup> Id. at 3-23 – 3-24.

<sup>45</sup> Id. at 3-25.

<sup>46</sup> Id. at 3-26.

<sup>47</sup> 2021 PRIA, *supra* note 3, at 4-43.

<sup>48</sup> Id. at 4-43.

<sup>49</sup> Memorandum on Modernizing Regulatory Review § 2(b)(ii), 86 Fed. Reg. 7223, 7223 (Jan. 25, 2021)).

available regulatory alternative are significantly more desirable.<sup>50</sup> Thus, the commenter asserts that the EPA should conduct a distributional analysis of the November 2021 Proposal and its alternatives to determine whether another approach may be more advantageous to disadvantaged communities.

Response I-6-11: EPA's EJ analyses focused on a baseline distribution of emissions from oil and natural gas sources, enabling the Agency to characterize risks due to oil and natural gas emissions prior to implementation of the rule. While the EPA agrees that baseline assessment alone is not the optimal approach for determining if EJ concerns exist, it was the only analytic approach feasible when preparing the November 2021 Proposal and December 2022 Supplemental Proposal RIAs.

## 6.3 EJ Outreach and Engagement

### *6.3.1 Need for Additional Communication and Outreach to Disadvantaged Communities*

Comment: Commenter (0911-North Dakota Petroleum Council (NDPC)) supports additional communication with and outreach to disadvantaged communities but does not understand by what authority under the CAA the EPA plans to regulate or enforce EJ considerations or negative externalities in a NSPS.

Response I-6-12: EPA finalized requirements regarding meaningful engagement associated with state plan development in the final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

### *6.3.2 Community-Based Initiatives*

Comment: Commenter (0734-ATS) suggests that community-based participatory research (CBPR) initiatives can help to engage communities affected by nearby oil and natural gas production facilities.<sup>51</sup> The commenter reports that such work from Los Angeles has demonstrated that individuals living nearby such sites, which have a higher proportion of low-income and minoritized residents, experience increases in asthmatic symptoms and lower lung function.<sup>52,53</sup> The commenter adds that historical practices of redlining and housing segregation in California contributed substantially to minoritized individuals only securing nearby housing

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<sup>50</sup> See Richard Revesz & Samantha Yi, Distributional Consequences and Regulatory Analysis, 52 ENV. LAW \_\_, \*35 (forthcoming 2022), [https://papers.ssrn.com/sol3/papers.cfm?abstract\\_id=3927277](https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3927277).

<sup>51</sup> Sullivan, J; Croisant, S; Howarth, M; Rowe, GT; Fernando, H; et al. Building and Maintaining a Citizen Science Network With Fishermen and Fishing Communities Post Deepwater Horizon Oil Disaster Using a CBPR Approach HHS Public Access. New Solut 28, 416–447 (2018).

<sup>52</sup> Shamasunder, B; Collier-Oxandale, A; Blickley, J; Sadd, J; Chan, M; et al. Community-based health and exposure study around urban oil developments in South Los Angeles. Int J Env. Res Public Heal. 15, 138 (2018).

<sup>53</sup> Johnston, JE; Enebish, T; Eckel, SP; Navarro, S & Shamasunder, B. Respiratory health, pulmonary function and local engagement in urban communities near oil development. Env. Res 197, 111088 (2021).

oil and natural gas extractive areas.<sup>54</sup> The commenter recommends that EPA outlines clear recommendations to ensure that oil and natural gas producers engage local communities to participate in decisions regarding new extraction and refining operations and to participate in local monitoring strategies. Furthermore, the commenter suggests that funds be allocated to ensure that CBPR initiatives can monitor the community health and environmental impacts of nearby oil and natural gas facilities.

Response I-6-13: EPA finalized requirements regarding meaningful engagement associated with state plan development in the final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

## **6.4 Proposed Rule Will Result in Adverse Economic Impacts/Environmental Justice Economic Impacts**

Comment: Commenter (0803-Ohio Oil and Gas Association (OOGA)) contends that the November 2021 Proposal will stifle oil and gas development in Ohio which will result in inverse EJ and significant negative impacts to Ohio's economy. While U.S. EPA's intentions are seemingly well intentioned, the commenter states that the U.S. EPA's analysis and considerations in this regard are, at best, one sided. According to the commenter, the additional and more stringent controls required under the November 2021 Proposal impose substantial burdens on the industry that will inevitably render many operations, particularly low production wells, economically infeasible. The commenter adds that the U.S. EPA fails to recognize that the oil and gas industry provides necessary and critical services to overburdened and underserved communities and that the impact of November 2021 Proposal on the industry effectively results in "inverse" environmental justice in these communities. Notably, for example, there are approximately 61,000 active wells in Ohio. The commenter notes that about 60 percent of the wells in Ohio involve private contractual relationships between the producer and the landowner to take a limited amount of natural gas for the Lessor's private domestic use (*e.g.*, heat a farmhouse, supply fuel for cooking, etc.). The commenter states that this means that there are approximately 36,700 rural Ohioans who have direct access to natural gas because of oil and gas facilities. The commenter concludes that compliance with U.S. EPA's November 2021 Proposal will challenge the future viability of well operations in rural Ohio which will have a significant negative impact on the people in those communities.

Commenter (0911-NDPC) fears that potentially extraneous and overly burdensome new requirements would have the reverse impact on economically and socially disadvantaged communities by steering oil and gas investment away from communities of need.

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<sup>54</sup> Cumming, DG. Black Gold, White Power: Mapping Oil, Real Estate, and Racial Segregation in the Los Angeles Basin, 1900-1939. *Engag Sci Technol Soc* 4, 85–110 (2018).

Commenter (1301-Northern Arapaho Tribe Business Council) suggests that EPA recognize the challenges for relatively small owners and operators such as the Tribe and help mitigate economic impacts to small operators by providing for streamlined or phased-in compliance. Given the noted EJ implications of the Rule, the commenter suggests prioritizing measures that improve local air quality and health impacts.

Response I-6-14: EPA's NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. Pursuant to section 603 of the RFA, EPA prepared an FRFA that examined the impact of the rule on small entities along with regulatory alternatives that could minimize that impact. The complete FRFA is available for review in the Regulatory Impact Analysis (RIA) (see section 4.4).

Comment: Commenters (0814-Independent Petroleum Association of America (IPAA) *et al.*, 0836-Domestic Energy Producers Alliance (DEPA)) express that the EPA should take into consideration that many rural areas of this country rely on oil and gas industry for their livelihood.

Commenter (0814-IPAA *et al.*) states that the EPA's November 2021 Proposal dedicates extensive discussion to ensure "robust and meaningful public engagement" with "underserved or overburdened communities." The commenter adds that the EPA focuses on the "particularly vulnerable to the climate and health impacts of pollution from this source category." The commenter supports such efforts. The commenter reminds EPA that in many rural areas of this country that "this source category" is not simply something defined by the CAA but it is their livelihood – it allows them to heat their homes and hopefully stay above the poverty level. The commenter adds that workers in this source category and their families live and breathe in close proximity to these emissions sources – they care what is being emitted. EPA's November 2021 Proposal represents a real threat to these rural communities. Homeowners and farms often rely on the gas from wells located on their property or pipelines that transverse their property to heat their homes and/or provide critically important income.

Commenters (0814-IPAA *et al.*, 0836-DEPA) note that, beyond the homeowners and farmers that directly rely on gas from wells on their property and/or pipelines that transverse their property, there are many communities that rely exclusively on gas supplied by low production/marginal wells located geographically close to their homes and would not be served if certain low production wells are shut-in because the small, local oil and natural gas company cannot afford to comply with the regulations in the November 2021 Proposal. While the citizens of these rural parts of the country are certainly concerned with the "climate and health impacts of pollution from this source category" – they are also concerned with their livelihood and putting food on the table. The potential impacts of the November 2021 Proposal extend well beyond the operators in this "source category." According to the commenters, consideration of the impact to the numerous "mom and pop" companies selling gas, food, lodging, etc. that rely on this source category needs to be factored into the "environmental justice implications" of the November 2021 Proposal in order to constitute "meaningful engagement" of "underserved and overburdened communities." The commenters state that the November 2021 Proposal crunches numbers to support "cost-effective" controls. They add that EPA also engages in an interesting discussion of what constitutes the "best system of emission reduction" (BSER) and the "cost" of

achieving such reduction. The commenters suggest that describing or defining what is "reasonable" as something not "exorbitant" and not something "greater than the industry could bear and survive," by individuals that in most cases have never been to these rural areas of the country is not comforting to the members and their dependent families of employees. The commenters supports EPA's efforts to go beyond the numbers and to better understand the real impact of the November 2021 Proposal on rural populations of this country.

Commenter (0946-Michigan Oil and Gas Association (MOGA)) reminds the EPA that many "underserved or overburdened communities" are often located in rural areas where oil and gas drilling and production provides jobs and sustains local economies. The commenter is concerned that the proposed future new source performance standards (NSPS) OOOOb and emission guidelines (EG) OOOOc will likely result in the early plugging of marginal wells that cannot absorb the initial implementation and ongoing costs of the proposed regulations. The commenter states that plugging of wells will have a direct impact on associated small businesses, including hotels, restaurants, service, retail and other "mom and pop" stores that rely on the oil and gas industry to survive. The commenter recommends that EPA consider the economic impacts on these small rural "underserved or overburdened communities" when determining the cost benefit analysis for the minimal reduction of methane from marginal wells.

Commenter (0727-OSEE/ODEQ) expresses concern that the proposed rule's focus on environmental justice may not take into consideration its potential economic effects on EJ communities within oil and gas dependent economies and that the proposal does not provide fair consideration of the economic impacts in distressed rural communities that may not meet EPA's definition of "environmental justice community." The commenter encourages EPA to broaden its evaluation of the costs and benefits of the proposed rule to incorporate economic effects with the same level of granularity that was used in targeting communities living in proximity to facilities that would be subject to this rulemaking. In particular, how will these policies affect employment in economically-distressed rural communities in states like Oklahoma?

Commenter (0727-OSEE/ODEQ) is concerned that EPA's analysis is just too vague and too broad-brush. The commenter suggests that important questions need to be addressed. How many marginal wells are expected to close as a result of the proposed rules? How many jobs are expected to be lost and which communities are likely to experience those losses? The commenter notes that it may be challenging to attempt to address these issues with sufficient rigor, but an attempt is certainly warranted to justify policies that will have disproportionate impacts on some communities to benefit the entire public. To conclude, the commenter states that they do not object to the evaluation of environmental impacts on environmental justice communities, but respectfully request EPA perform a similarly detailed and rigorous analysis of economic impacts, especially in rural communities.

Response I-6-15: EPA disagrees it did not weigh the economic impacts on vulnerable communities, especially rural communities, as carefully as the environmental benefits. Employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas related activities and associated industries

might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products. However, regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes. At this time, EPA is unable to quantify well shut-in or employment shifts, either jobs losses in the oil and gas sector and oil and gas communities, or subsequent jobs gains in other sectors or locations. For more information, see EPA's final RIA.



## Chapter 7. Fugitive Emissions from Well Sites

### 7.1 Fugitive Emissions from Well Sites

#### 7.1.1 General Support

Comment: Several commenters (0196-Evangelical Environmental Network (EEN), 0443-Seventh Generation Interfaith Inc. (SGI), 0455-Radio Drama Network, Inc. (RDN), 0460-Trinity Health, 0538-Change Finance, PBC (Change Finance), 0559-TX State Senator Eckhardt, 0737-Clarke Valve, 0766-Cheniere Energy, Inc. (Cheniere), 0782-Berkshire Hathaway Energy Company (BHE), 0789-Pennsylvania Department of Environmental Protection (PA DEP), 0932-GHGSat, Inc., 1382-National Grid, 1389-VERIS Wealth Partners, 1372-Generate Capital, PBC (Generate), 0728-Calvert Research and Management (Calvert), 0724-Boston Trust Walden, 0720-Miller/Howard Investments, Inc. (MHI)) express general support for EPA's November 2021 Proposal to reduce methane emissions from the oil and gas segment. Several of the commenters urge the EPA to ensure strong methane emission performance standards by crafting a regulation that maintains or expands strong leak monitoring and repair standards, including through expanded use of advance leak detection technologies.

Commenter (0782-BHE) argues even without broad federal mandates for existing sources, LDAR programs have been “built out” within natural gas operations in response to NSPS OOOOa, voluntary programs, and state mandates. The November 2021 Proposal explores alternatives to current LDAR programs, such as tiered programs where leak mitigation schedules, reporting and other requirements are dependent on leak size. While leak mitigation program flexibility is a worthy goal, in general it may be premature to adopt LDAR replacement programs because technology such as component-level leak quantification is not yet available to quickly and cost effectively measure leak rates. Even as technology barriers are addressed, any “new” program elements should be added as optional alternatives rather than supplant established LDAR programs. For future scenarios that add alternative options, commenter (0782-BHE) recommends that EPA retain these standard LDAR programs and avoid adding complications or replacing current LDAR with alternatives. The current programs have been established across the asset base and have proven effective at eliminating most leaks and reducing leak emissions. Prescribed replacement of the current LDAR programs would inappropriately impugn existing and successful programs and introduce significant burden to build out new replacement programs without justification for such an outcome. Similarly, EPA requested feedback on programmatic approaches for LDAR such as subcategorization. The commenter recommends not adding such approaches to the existing, established LDAR approach because of potential complications. Commenter (0782-BHE) recommends that EPA explore development of alternative optional leak mitigation approaches through systematic development and demonstration of the alternatives.

Commenter (0789-PA DEP) notes that in Pennsylvania's experience, implementing quarterly leak detection and repair (LDAR) provisions has proven to be a cost-effective method to reduce methane emissions for new or modified natural gas production at unconventional wellsite, compression, processing, and transmission facilities. Accordingly, the commenter encourages EPA to include quarterly LDAR inspection requirements for all new or modified natural gas

production, compression, processing, and transmission facilities in the proposed rule. If an exemption is included in the rule, the commenter encourages EPA to consider limiting the exception to facilities which do not include equipment that is highly prone to failure.

Commenters (1389-VERIS Wealth Partners, 1372-Generate Capital, 0728-Calvert, 0724-Boston Trust Walden, 0720-MHI) urge EPA to ensure strong methane emission performance standards by crafting a regulation that includes all potentially significant sources of methane emissions, including smaller leak-prone wells, under emission standards.

Response I-7-1: EPA acknowledges the commenters support for the November 2021 Proposal's requirements for fugitive emissions components located at well sites. See discussion in section IV.A.1 of the December 2022 Supplemental Proposal for additional response to comments requesting strengthening of these standards.<sup>1</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions components located at well sites.

Comment: Commenter (0752-American Forest & Paper Association (AF&PA) and The Process Gas Consumers Group (PGC)) states that the pulp and paper industry and certain members spent approximately \$2.56 billion to purchase natural gas in 2018. Making a conservative assumption that leakage comprises a small percentage of the total gas purchased, it is estimated that the PGC spent at least \$50 million in 2018 for natural gas they did not receive due to leakage. Importantly, this estimation does not consider the costs of pipeline service disruptions from natural gas leakage. The commenter asserts that LDAR requirements in the proposed regulations could increase the safe and reliable operation of natural gas pipelines and reduce losses and these types of incidents.

Response I-7-2: EPA acknowledges the commenter's support for the November 2021 Proposal's standards for fugitive emissions components at well sites.

Comment: Commenters (0920-We Act for Environmental Justice (WAEJ); 1338-Lexington Climate Action Network (Lexington-CAN)) urge EPA to consider additional measures in order to reach the ambitious goal of reducing methane emissions 65 percent by 2025 (only 3 years from now) by making sure that all wells are subject to regular and frequent LDAR. Commenter (0920-WAEJ) urges the EPA to require companies to address leaks from ALL wells, including smaller wells as well as compressor stations and storage vessels, regardless of their potential to emit (PTE), ensuring they are subject to continuous LDAR as frequently as possible. EPA should work with the Department of Interior, which is responsible for distributing funds from the bipartisan infrastructure law, to identify and plug highly polluting orphan oil and gas wells across the country.<sup>2</sup>

Response I-7-3: EPA acknowledges the commenters support for the November 2021 Proposal's requirements for fugitive emissions components located at well sites. See discussion in section IV.A.1 of the December 2022 Supplemental Proposal for additional response to comments

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<sup>1</sup> 87 FR 74722-74736 (December 6, 2022).

<sup>2</sup> Grist, Abandoned oil well counts are exploding — now that there's money on the table (2022), <https://grist.org/energy/abandoned-oil-wells-cleanup-infrastructure-law/>.

requesting strengthening of these standards.<sup>3</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0949-Liveable Arlington) requests that EPA require 24-hour air monitoring for new and existing wells within half a mile of homes, schools, preschools, daycares, and medical centers. Automatic LDAR inspections should be required when air monitors show elevated levels of hazardous air pollutants (HAP). The commenter asks that EPA immediately deploy the best available emissions control technology. The commenter recommends monthly LDAR for all new and existing wells.

Commenters (0942-CleanEarth4Kids.org, 0937-Fort Berthold Protectors of Water and Earth Rights (Fort Berthold POWER), 0947-Alliance of Nurses for Healthy Environments-Colorado (ANHE-CO) *et al.*, 1339-Waterway Advocates) suggest the administration take immediate action to cut methane pollution by at least 65 percent for 2025 by requiring all wells, regardless of their size or PTE, to be monitored for monthly LDAR. The commenters assert that these reports must be publicly available.

Commenter (0841-Red Mesa Chapter Governance-Navajo Nation (RMCG-Navajo), 0840-Counselor Chapter House-Navajo Nation (Counselor-Navajo)) urge EPA to strengthen its final rule by eliminating loopholes that allow certain wells to forgo regular inspections and require regular monitoring at smaller, leak prone wells.

Response I-7-4: See discussion in section IV.A.1 of the December 2022 Supplemental Proposal for response to comments requesting strengthening of these standards.<sup>4</sup> See discussion in section IV.B.2 for response to comments related to the use of continuous monitoring systems.<sup>5</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to continuous monitoring under the advanced methane detection technology program.

Comment: Commenter (0786-Enerplus Resources (USA) Corporation (Enerplus)) has concentrated on technology and engineering to eliminate potential leak points through improved facility design and operation. The commenter specifically discusses a lock-down thief hatch system, which, according to the commenter, is a significant technological advancement to address leaks. More details on the technology are provided in the commenter's letter. The commenter requests reduced inspection frequencies for facilities engineered to eliminate and prevent leaks. Provisions for this allowance will encourage technological innovation across the industry.

Response I-7-5: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A of the

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<sup>3</sup> 87 FR 74722-74736 (December 6, 2022).

<sup>4</sup> 87 FR 74722-74736 (December 6, 2022).

<sup>5</sup> 87 FR 74744 (December 6, 2022).

December 2022 Supplemental.<sup>6</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0570-Konica Minolta Sensing Americas, Inc. (Konica)) states large leaks can be easily found even at long distances such as at the entrance to a facility. Therefore, the commenter considers periodic screening with an OGI as a practical solution. Many oil and gas operators and service companies already have or are considering OGI cameras, and they would utilize their own assets as much as possible. Therefore, the commenter believes it is possible to give operators flexibility in their choices while achieving emission reduction goals.

Response I-7-6: EPA agrees that providing owners and operators flexibility in achieving emission standards is appropriate. EPA proposed specific provisions for the use of advanced methane measurement technologies for both periodic screening and continuous monitoring as an alternative to OGI in the 2022 Supplemental Proposal (see Section IV.B.) The final NSPS OOOOb and EG OOOOc include provisions for the use of alternative test methods using advanced methane detection technologies that allow for periodic screening or continuous monitoring for fugitive emissions.

### ***7.1.2 Definitions Related to Fugitive Emissions Components***

Comment: Commenter (0737-Clarke Valve) encourages EPA to change the definition of a “leak” from 500 parts per million (ppm) to 50 ppm. It has been known for decades that methane is far more potent than carbon dioxide, as is reflected in the November 2021 Proposal.<sup>7</sup> Therefore, allowing emissions up to 500 ppm to continue accommodates aging seal technology, while significant scientific and material advances have been available for the last few decades that easily allow manufacturers to meet a more stringent standard. In fact, several valve manufacturers already are using widely available mature seal technology, such that their valves are achieving emissions below 50 ppm, the commenter notes. On the other hand, some of the largest valve manufacturers will only adhere to the minimum requirements in law, which is why the new requirements must be as stringent as possible to achieve maximum emissions reductions.

The commenter (0737-Clarke Valve) also encourages EPA to continue to further explore all options to reduce fugitive emissions, with a particular emphasis on control valves, where an immediate and significant impact can be achieved in the reduction of fugitive emissions. Currently, when analyzing types of equipment, although unintended, fugitive emissions from control valves are estimated to account for approximately 60 percent of total fugitive emissions.<sup>8</sup>

Response I-7-7: The BSER for fugitive emissions components is a fugitive emissions monitoring and repair program that includes audio, visual, and olfactory (AVO) monitoring with or without OGI monitoring, depending on the equipment at the well site or centralized production facility.

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<sup>6</sup> 87 FR 74722 (December 6, 2022).

<sup>7</sup> Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Proposed Rule), 86 Fed. Reg. 63110 (Nov. 15, 2021).

<sup>8</sup> Mackay, James E., and Kevin J. Smith. Monitoring and Containment of Fugitive Emissions from Valve Stems – Electrical Conductivity and Gas Adsorption Measurements on Metal Oxides. Department of Chemical and Biological Engineering, University of British Columbia.

EPA Method 21 is an allowed alternative to the OGI monitoring, where a leak is defined as an instrument reading of 500 ppm above background or greater.

Comment: Commenter (0793-Permian Basin Petroleum Association (PBPA)) states that EPA has proposed that emissions resulting from control devices operating in a manner that are not in full compliance with any federal rule, state rule, or permit “are also considered fugitive emissions.” See 86 Fed. Reg. at 63,170 & 63,247. Fugitive emissions components have traditionally been those associated with process equipment. See, e.g., 40 C.F.R. §60.5430a (defining “fugitive emissions component” to include those components associated with process equipment, such as “valves, connectors, pressure relief devices, open-ended lines, flanges, covers and [certain] closed vent systems.”). While malfunction-type emissions from control devices would be unauthorized emissions potentially subject to permit-driven reporting requirements, there is no reasoned basis for characterizing those as fugitive emissions.

Response I-7-8: In response to comments received on the November 2021 Proposal, EPA revised the fugitive emissions components definition to not include control devices in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal.<sup>9</sup> Please also see section X.A of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenter (0573-Kansas Department of Health and Environment (KDHE)) states that in anticipation of the potentially very large number of emission surveys that will need to be performed under this rule at its outset, particularly at low-emitting well sites, keeping the option of EPA Method 21 would help mitigate bottlenecks for owners/operators being able to carry out survey requirements.

Response I-7-9: Consistent with the November 2021 Proposal and the December 2022 Supplemental Proposal, the final NSPS OOOOb and EG OOOOc retain EPA Method 21 as an allowed alternative to OGI monitoring.

Comment: Commenter (0844-Environmental Defense Fund (EDF) *et al.*) notes that as EPA has recognized that “[a] key factor in evaluating how to target fugitive emissions is clearly identifying the emissions of concern and the sources of those emissions.”<sup>10</sup> According to the commenter, EPA has also correctly recognized that “data shows that the universe of components with potential for fugitive emissions is broader than the illustrative list included in the 2016 NSPS OOOOa, and that the majority of the largest emissions events occur from a subset of components that may not have been clearly included in the definition.”<sup>11</sup> The commenter supports EPA’s November 2021 Proposal to expand the definition of fugitive emission components to more broadly encompass significant emissions sources and offer a few

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<sup>9</sup> 87 FR 74705; December 6, 2022.

<sup>10</sup> 86 Fed. Reg. 63,169.

<sup>11</sup> *Id.*

recommendations on how EPA can further strengthen this definition to achieve the aims articulated in the November 2021 Proposal.

The commenter (0844-EDF *et al.*) recommends amending the proposed definition as follows (additions underlined and deletions struck out):

any component or piece of equipment with components that has the potential to emit fugitive emissions of methane and VOC at a well site (including a centralized production facility or tank battery) or compressor station, including but not limited to all valves, connectors, PRDs, open-ended lines, flanges, ~~all~~ covers and closed vent systems, ~~all~~ thief hatches ~~or~~ and other openings on ~~a controlled~~ any storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers, ~~or~~ natural gas-driven pumps, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals and diaphragms, separators, pressure vessels, dehydrators, heaters, flares, and other control devices. ~~However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from Emissions detected during fugitive monitoring from natural gas-driven pneumatic controllers, natural-gas driven pneumatic pumps, flares, and other control devices are not considered fugitive emissions only if the device is operating in a manner that is not in full compliance with any all applicable Federal rules, State rules, or and permits. are also considered fugitive emissions components.~~

The commenter (0844-EDF *et al.*) believes these recommended changes would reduce ambiguity about fugitive monitoring and what is considered a fugitive emission. The commenter recommends including equipment types in the definition to avoid ambiguity that might cause certain sources of fugitive emissions to not be surveyed (*e.g.*, separators are not included in the proposed definition even though separator dump valves are a known significant source of large fugitive emission events.) Under a proper reading of the proposed definition, separator dump valves should be included within the term “valve.” But to avoid ambiguity, the commenter believes EPA should include certain equipment types like separators in the definition so it is clear that monitoring of separator dump valves and components on all other equipment is required.

The commenter (0844-EDF *et al.*) also recommends including “centralized production facility” and tank batteries as affected facilities where fugitive monitoring is required. Again, under a proper reading of the proposed definition, the commenter thinks monitoring would be required at these sites. But including a specific reference or a cross-reference to the affected facility definition is important to avoid ambiguity and ensure fugitive monitoring occurs at tank batteries and other centralized production facilities, which are known large sources of fugitive emissions.

The commenter (0844-EDF *et al.*) thinks that EPA should include a non-exhaustive but more comprehensive list of fugitive emission components and equipment. Including a greater variety of components will help ensure they are not overlooked during fugitive monitoring and will reduce the potential for interpretations that might incorrectly narrow the scope of fugitive

monitoring. In Colorado, for example, fugitive monitoring is required at “well production facilities.”<sup>12</sup> Well production facility means:

*all equipment* at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.<sup>13</sup>

In the commenter’s opinion (0844-EDF *et al.*), it is critical that EPA must avoid circularity in the definition that could be interpreted as not requiring fugitive monitoring for venting components and control devices if the operator believes the components are operating as intended. Fugitive monitoring must be required at venting components (like pneumatics) and control devices (like flares) *for the purpose of determining* if the device is operating properly or not.<sup>14</sup> The commenter believes that as currently written, an operator might believe that a flare or venting pneumatic is operating as intended and decide that it does not need to be surveyed for fugitive emissions. However, monitoring is the only way to ensure such a device is operating correctly and not malfunctioning and emitting at greater levels than intended. The commenter suggests that EPA make clear that all gas-driven pneumatics, flares, and other control devices are subject to fugitive monitoring no matter whether they are operating correctly or not.<sup>15</sup> A clear regulatory definition explaining that fugitive emissions include impermissible vented emissions (*i.e.*, those exceeding permissible levels or due to malfunctions) is also important for the structure and follow-up requirements of advanced monitoring.<sup>16</sup>

Response I-7-10: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>17</sup> Please also see section X.A of the preamble to the final rule which details EPA’s

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<sup>12</sup>Colo. Code Regs. § 1001-9, Pt. F, § N, p. 287 (“‘Well production facilities’ are also subject to LDAR requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source[.]”).

<sup>13</sup>Id. at Pt. D, § I.B.30 (emphasis added).

<sup>14</sup>See, e.g., Cal. Code Regs. Tit. 17, § 95667, <https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf> (requiring leak monitoring at natural gas driven pneumatic controllers and pumps).

<sup>15</sup>According to the International Energy Agency, flare efficiency and methane slip is “an area often overlooked by regulators.” IEA analysis shows “in 2020, flares leaked on average around 8% of the natural gas and natural gas liquids that should have been combusted – more than double previous estimates. Incomplete combustion from flares accounted for about 10% of total oil and gas methane emissions, 95% of which was avoidable.” The best way to prevent emissions from flares is eliminating flaring entirely, as discussed in Part IV.I (flaring). IEA, Curtailing Methane Emissions from Fossil Fuel Operations: Pathways to a 75% Cut by 2030 (October 2021), <https://www.iea.org/reports/curtailing-methane-emissions-from-fossil-fuel-operations>.

<sup>16</sup> See Part IV.A.3 (advanced monitoring) of the commenter’s letter; see also Fox et al., A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas, 14 Env. Res. Lett. 053002 (2019), <https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf> (discussing regulatory equivalence issues stemming from advanced methods’ inability to distinguish between fugitive and vented emissions).

<sup>17</sup> 87 FR 74723 (December 6, 2022).

final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenters (0755-Texas Pipeline Association (TPA), 0803-Ohio Oil & Gas Association (OOGA), 0817-GPA Midstream Association (GPA), 0911-North Dakota Petroleum Council (NDPC), 0938-Texas Oil & Gas Association (TXOGA)) believe EPA's proposed definition of "fugitive emission component" is too broad and covers too many potential emission sources. Some commenters specifically object to the inclusion of emissions from non-regulated sources and malfunctioning controllers and control devices.

The commenter (0755-TPA) questions the November 2021 Proposal because the line between "operating properly" and not "operating properly" with this type of equipment is, in many cases, far from clear and the determination is often highly subjective in nature. In particular, the criteria for determining a malfunctioning device from an OGI survey is subjective, not objective. Finalization of this sort of definition would leave owners and operators with continuing questions and uncertainty as to whether, in a given circumstance at a given facility, a particular piece of equipment was included in the definition of "fugitive emissions component" such that the NSPS applied. This sort of uncertainty adds undue regulatory burden and makes compliance difficult, and in many cases a subjective guessing game. The emissions requirements related to control devices and pneumatic controllers should be handled under the rules governing each specific affected source type, not under rules applicable to fugitive emissions generally.

The commenter (0755-TPA) thinks it is important that EPA limit the list of fugitive emission components to equipment that is not designed to vent as part of its intended operations, so as to keep the rules' focus on equipment that creates emissions as the result of an abnormal, unintended condition that needs to be repaired. Removing equipment such as thief hatches and crankcase vents, which are intended to release emissions as part of normal operations, would bring the definition more in line with the traditional concept of what constitutes a fugitive emissions component, *i.e.*, a piece of equipment that is emitting fugitive emissions due to unintended malfunction, not intended operations. Narrowing the list in this manner would also have the benefit of reducing the number of individual components that would be subject to the extensive survey, repair, replacement, and recordkeeping/reporting requirements that would apply to components covered by the fugitive emissions rules. The application of such onerous requirements should be as limited as possible, and in no event should such requirements be applied to equipment that is allowing emissions as an integral part of its design and operations. The commenter notes that EPA did not include an unrealistically expansive list of fugitive emissions components in other rules, *e.g.*, LDAR regulations in subpart VVa, lists only the following covered equipment: "pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart."<sup>18</sup> Notably, this list does not include equipment types that are designed to vent as part of intended operations. The commenter argues in finalizing the list of fugitive components in this rulemaking, EPA should compose a list that is similarly reasonable and realistic.

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<sup>18</sup> 40 CFR § 60.481 a.



The commenter (0803-OOGA) requests that EPA exclude safety equipment (*e.g.*, pressure relief valves), which only emit out of necessity in an emergency situation, from the definition of “fugitive emissions component.” It is unclear whether such emissions are treated as “malfunctioning controllers” under the November 2021 Proposal. Regardless, safety equipment are integral and necessary components and the activation of such equipment resulting in emissions should not be treated as a malfunction nor otherwise regulated and included in the baseline methane emission estimate.

Commenter (0817-GPA) states that the November 2021 Proposal provides no basis for assuming OGI cameras can detect control device malfunctions. The commenter does not understand why EPA believes OGI cameras could detect malfunctioning control devices or how/if EPA evaluated a recent EPA Region 8 study examining OGI observations of enclosed combustion devices and their correlation to analyzer sampling.<sup>19</sup> The study does not reach a conclusion on the effectiveness of OGI to detect a malfunctioning control device and indicates there is no obvious comparison between stack test data and OGI observations. The study demonstrates the difficulty in distinguishing between control device heat signatures and emissions and identifies the challenges of using an OGI camera to determine if enclosed combustion devices are meeting desired combustion efficiencies. The commenter suggests EPA should address this study.

If EPA requires the use of OGI cameras to identify control device malfunctions, the commenter (0817-GPA) requests that it allow operators to take additional confirmatory steps prior to effectuating any repairs. After an OGI camera operator believes they have detected a malfunctioning control device, EPA should require the operator to first confirm the malfunction through other information, such as reviewing operating conditions at the facility based on thermocouple readings, flow rates, level indicators, gas analyses, and physical inspection of equipment. If this information fails to show a control device malfunction, then the operator should not be required to take any further action.

Response I-7-11: In the December 2022 Supplemental Proposal made significant revisions to the definition of fugitive emissions components that was proposed in November 2021. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>20</sup> Please also see section X.A of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites, including the final definition of fugitive emissions components, which does not include control devices or controllers. Please also see section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenters (0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ), 0817-GPA, 0911-NDPC, 0938-TXOGA) state that EPA seems to be using a different definition for fugitive emissions in the

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<sup>19</sup> EPA, Region 8, Wyoming Department of Environmental Quality, Measuring Enclosed Combustion Device Emissions Using Portable Analyzers (May 14, 2020).

<sup>20</sup> 87 FR 74723-74724 (December 6, 2022).

November 2021 Proposal than has been historically used in New Source Review (NSR) and Title V. In 40 CFR 70.2, fugitive emissions are defined as:

“those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.”

The commenter (0727-OSEE/ODEQ) indicates that in the November 2021 Proposal it is stated that:

“...fugitive emissions are unintended...” and “... not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specification.”

The commenters (0727-OSEE/ODEQ, 0911-NDPC) feel these statements are inconsistent and inaccurate. The EPA should consider that not all emissions can reasonably be routed to a control device or back into the process. Technical feasibility should be a consideration and option for any natural gas-driven pneumatic device standard.

The commenters (0727-OSEE/ODEQ, 0938-TXOGA) note that the November 2021 Proposal states that it would change and expand the definition of “fugitive emissions component” for the purpose of regulating the group of all fugitive emissions components at well sites and compressor stations<sup>21</sup>, providing:

[D]ata shows that the universe of components with potential for fugitive emissions is broader than the illustrative list included in the 2016 NSPS OOOOa, and that the majority of the largest emissions events occur from a subset of components that may not have been clearly included in the definition.<sup>22</sup>

The commenters (0817-GPA, 0938-TXOGA) indicate that it seems that the November 2021 Proposal anticipates including equipment that is already regulated and controlled in other sections of the subpart and should be removed from the definition to avoid ambiguity. For example, the commenter (0938-TXOGA) states that the current definition of “fugitive emissions component” under NSPS OOOOa specifically does not include covers and closed vent systems regulated under 40 CFR §§60.5411 or 60.5411a and thief hatches or other openings on a controlled storage vessel subject to §60.5395 or §60.5395a.<sup>23</sup> In the November 2021 Proposal, the commenter (0938-TXOGA) says that EPA seems to be reversing, without adequate explanation and conduct of reasoned decision making, equipment EPA previously considered and decided not to include in the definition in response to comments on the 2016 NSPS OOOOa

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<sup>21</sup> 86 Fed. Reg. at 63,169-170.

<sup>22</sup> Id. at 63,169.

<sup>23</sup> See 40 C.F.R. § 60.5430a (“Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to § 60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.”) (emphasis added).

proposed rule.<sup>24</sup> The commenters (0817-GPA, 0938-TXOGA) argue the November 2021 Proposal does not establish a basis for expanding this definition, and EPA needs to complete the required procedural steps if it wishes to do so.

The commenter (0817-GPA) indicates the November 2021 Proposal never discusses these aspects of the definition of “fugitive emission component” under 40 CFR §60.5430a or any of the exemptions to it. Nor does it acknowledge that covers, thief hatches, and closed vent system are already regulated by the Section 60.5411a work practice standards. Given the absence of either proposed regulatory language or discussion in the November 2021 Proposal preamble, the commenter does not know whether EPA intends to eliminate these work practice standards in lieu of fugitive emission monitoring or require adherence to both monitoring and work practice standards, much less why EPA is changing its position.

The commenter (0727-OSEE/ODEQ) notes that fugitive emissions components have not included sources of emissions that are vented to the atmosphere through a stack or something similar. If EPA intends for these additional sources to be included in an OGI survey, they should not be included within the fugitive source definition. If EPA insists on adding true point sources to the definition of “fugitive emissions component,” then EPA may need to provide additional clarification regarding the requirement to use the actual stack height for a flare subject to reporting requirements for emissions inventory purposes, since fugitive components have different parameters for characterizing the release.

Response I-7-12: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>25</sup> Please also see section X.A of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenter (0785-John Crane Inc.) recommends that EPA adopt the proposed definition of “fugitive emissions component” based on its increased inclusion of component types as compared to the prior definition. Prescriptive policies that target a subset of specific infrastructure could disincentivize emissions reduction for several large emitters previously left out of scope, in the commenter’s opinion.

Response I-7-13: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>26</sup> Please also see section X.A of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble

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<sup>24</sup> See 81 Fed. Reg. at 35,858.

<sup>25</sup> 87 FR 74723 (December 6, 2022).

<sup>26</sup> Id.

to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenter (0737-Clarke Valve) states control valves also leak through the stem of the valve. These emissions have a major impact, in terms of the emissions footprint of any facility or production unit. Thus, the commenter requests that EPA consider including in its rules going forward fugitive emissions from the stem of the control valve.

Response I-7-14: The definition of fugitive emissions component already includes valves, which include emissions from any part of the valve, including the stem. Therefore, no change to the definition is necessary for this purpose.

Comment: Commenters (0802-Kraken Oil & Gas LLC (Kraken), 0831-American Exploration and Production Council (AXPC)) ask that EPA maintain the definitions for fugitive emissions and fugitive emission components as defined in the 2016 NSPS OOOOa rule.

The commenters (0802-Kraken, 0831-AXPC) note that EPA's proposed definition conflicts with the current definition of fugitive emissions used in EPA's NSR and Title V permitting programs. Therefore, the commenters recommend that EPA revise the definition to be consistent with the current definitions used by EPA.

The commenter (0802-Kraken) provides two definitions of fugitive emissions:

The Montana Administrative Code, Chapter 17.8 – Air Quality, Section 17.8.101 – Definitions include the following definition of fugitive emissions:

(20) "Fugitive emissions" means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

(41) "Stack, vent, or roof monitor" means any flue, conduit, chimney, vent, or duct arranged to conduct emissions.

The North Dakota Administrative Code, Article 33.1-15 Air Pollution Control, 33.1-15-01-04. Definitions include the following definition of fugitive emissions:

14. "Fugitive emissions" means solid airborne particulate matter, fumes, gases, mist, smoke, odorous matter, vapors, or any combination thereof generated incidental to an operation process procedure or emitted from any source other than through a well defined stack or chimney. 47. "Stack or chimney" means any flue, conduit, or duct arranged to conduct emissions.

The commenter (0831-AXPC) adds, 40 CFR 70.2 defines fugitive emissions as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening." EPA's NSR and Title V regulations do not consider whether a source is operating properly to determine if their emissions are fugitive. Instead, for the new source rule, it should be determining if it could reasonably (or is it technically feasible) to pass through a stack, chimney, vent, or other functionally equivalent opening.

The commenter (0831-AXPC) states with respect to pneumatic devices, not all pneumatic devices are able to connect piping to route vented gas back into a lower pressure process or to a control device. The commenter provides a figure showing a vent that can be unscrewed and has standard pipe threads that can be adapted to piping on the left and a pneumatic device that does not have that capability on the right.

Response I-7-15: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>27</sup> Please also see section X.A of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

Comment: Commenters (0831-AXPC, 0808-American Petroleum Institute (API)) express various concerns related to the November 2021 Proposal's expansion of the definition of fugitive emissions component, including the proposal to classify a malfunction or operational upset as fugitive emissions.

The commenter (0831-AXPC) believes that the inclusion of control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any federal rule, state rule, or permit as a fugitive emission is wholly inappropriate for multiple reasons. It does not meet the long-standing and widely accepted definition of fugitive emissions and there is not a generally accepted methodology to inspecting a control device using current fugitive emission monitoring practices, AVO and OGI. The commenter (0808-API) similarly states that OGI and EPA Method 21 are not even feasible for flares and requests that EPA explain how these methods would apply or, conversely, prescribe acceptable and workable alternative methods under the LDAR program.

The commenter (0808-API) asks that the proposed definition be clarified. All other equipment included in the definition is not expected to leak (at least in any significant amount). As a result, when periodic leak monitoring is conducted, the goal is to discern the presence of a leak. In contrast, even well operating emissions control devices and flares will have a permissible level of emissions. Thus, a periodic LDAR-type emissions survey should be expected to detect some amount of methane or VOC emissions. This raises the question of what amount of emissions triggers the need for further action under the LDAR work practices, such as investigation and corrective action. The conceptual answer is an amount that represents noncompliance with applicable emissions or work practice standards. But the commenter indicates that the November 2021 Proposal does not describe a mechanism for determining what level of emissions corresponds to compliant conditions and how to determine the increased amount that represents actionable noncompliance. In other words, the rule does not define what constitutes a "leak" for purposes of emissions control devices or flares. To be workable, EPA must include such details in the final rule, the commenter recommends.

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<sup>27</sup> 87 FR 74723 (December 6, 2022).

Commenter (0808-API) believes that when work practice standards are fully implemented, emissions addressed by those standards cannot constitute a “violation.” The “no detectable emissions standard” is a work practice standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

Commenter (0808-API) points out that long ago, EPA rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the November 2021 Proposal to depart from its historical approach with regard to fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in compliance when a leak is detected, as long as the associated work practices requiring investigation and repair are followed.

According to the commenters (0831-AXPC, 0808-API), neither AVO nor OGI would be able to determine if the flare is not operating in compliance with federal, state or permit requirements; only a determination whether the flare is lit or unlit is possible with these methods. There is no published protocol that outlines how a control device should be observed with an OGI camera and what determines a malfunction. For example, a 95 percent control efficiency is allowed, so theoretically 5 percent of waste stream emissions are allowed to be emitted into the atmosphere.

The commenter (0831-AXPC) explains that malfunctions occur from mechanical equipment, but every malfunction may not be a potential violation of the underlying standards. There are some circumstances where EPA’s requirement to “take corrective action to complete all necessary repairs as soon as practicable and prevent reoccurrence of emissions,” could require a complete re-design of a facility. An example EPA includes is “unintentional gas carry through,” more commonly referred to as stuck dump valves (different than stuck liquid level controllers). The commenter explains that the root cause of unintentional gas carry through is typically that debris in a liquid line prevents a valve from closing. Most pressure vessel packages are not designed with a mechanism to catch debris prior to the valve, due to the infrequent occurrences when debris prevents the valve from closing. It is not cost effective in this example to implement a corrective action to prevent the emissions, but there are several options available to reduce the emissions.

The commenter (0831-AXPC) suggests the following language to better account for these situations:

In the case of a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule, this proposal would require the owner or operator to conduct a root cause analysis to determine why the emissions are present, take corrective action to complete all necessary repairs as soon as practicable and if reasonably feasible to prevent reoccurrence of emissions, and report the malfunction or operational upset as a potential violation of the underlying standards for the source of the emissions.

Response I-7-16: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to the definition of fugitive emissions components.<sup>28</sup> Please also see section X.A of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites and section XI.A.1.a of the preamble to the final rule which discusses responses to significant comments related to the definition of fugitive emissions components.

### ***7.1.3 Wellhead Only Well Sites***

#### **7.1.3.1 Clarification Needed**

Comment: Commenter (0831-AXPC) believes EPA needs to revise the proposed definition of “wellhead only well site.” As written, the definition of major production and processing equipment is too broad and will pull in sites that for all intents and purposes is a wellhead only well site. For example, a single storage vessel at a wellhead could meet the definition of “major production and processing equipment.” Although not routinely producing any sort of liquid, it’s common practice to see a single tank, at what is traditionally thought of at a wellhead only site, to ensure that if any liquid is ever recovered at the facility that there is proper storage and handling capacity to manage it.

The commenter (0831-AXPC) adds that natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines should not meet the definition of “major production and processing equipment” as each of these pieces of equipment do not function as the primary equipment for production and processing purposes, but instead, commonly serve in supplementary roles for the equipment characteristically associated with “major production and processing equipment.” Further, this equipment can all be found in operation with production and processing equipment at both well sites and wellhead only well sites. If they were to be included as “major production and processing equipment” it’s possible that no facilities would even qualify as a wellhead only well site. This ancillary equipment should be considered as such because they clearly do not meet the definition of “major production and processing equipment.”

The commenter (0831-AXPC) states that the definition should also include the type of production and lack of processing associated with wells that only have a storage tank and no other equipment installed at the same location. The storage vessel in this type of configuration serves as a secondary production collection point. These types of wellheads primarily produce gas and do so directly from the wellhead to the sales line. Liquid production is minimal from these wells, as the wellbore pressures are depleted and require rod lift to artificially produce liquids. There is no separation for production from these wells as the liquids produced are extremely minimal, removing any benefit or need for processing equipment. Because the storage tank is installed only to collect liquids that are inconsistently produced from the well, it cannot be defined as major production equipment, making the wellhead the only significant piece of equipment.

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<sup>28</sup> 87 FR 74723 (December 6, 2022).

Response I-7-17: The EPA acknowledges the concerns and requests for clarification as it relates to wellhead only well sites and major production and processing equipment.

The final rule maintains the definition of a wellhead only well site as follows:

*Wellhead only well site* means, for the purposes of the fugitive emissions standards at §60.5397b, a well site that contains one or more wellheads and no major production and processing equipment.

The EPA is finalizing a definition of major production and processing equipment that includes control devices, natural gas-driven process controllers, natural gas-driven pumps, and tank batteries, in addition to the previous equipment included in the definition in the December 2022 Supplemental Proposal. The final definition reads as follows, which EPA believes resolves the commenters concerns.

*Major production and processing equipment* means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

#### 7.1.3.2 Opposed to Exemption

Comment: Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0586-Navajo Nation Environmental Protection Agency (Navajo EPA), 0605-Muscogee (Creek) Nation, 0781-National Tribal Air Association (NTAA), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 0844-EDF *et al.*, 0943-Sault Ste. Marie Tribe of Chippewa Indians (Sault EPD)) disagree with EPA's November 2021 Proposal to retain the wellhead only well site exemption.

The commenters (0391-KBIC, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-Ute EPD, 0943-Sault EPD) say that even if these sites do not contain major production and processing equipment, they can contain smaller equipment that can leak or malfunction and are still capable of releasing, and still do release, fugitive emissions. Alternatively, EPA should narrow the definition of "wellhead only well sites" subject to this exemption so that sites that contain equipment with the potential to release fugitive emissions of methane and VOC are subject to the monitoring requirements. Given that wellhead only well sites connect to gathering facilities where fugitive emissions monitoring is required, the commenters do not believe requiring monitoring at these sites is infeasible or particularly costly.

The commenter (0844-EDF *et al.*) points out that emissions, including large emission events, have been observed at wellhead only well sites.<sup>29</sup> If EPA retains this exemption it should expand the definition of major production and processing equipment to ensure no equipment with potentially significant emissions is located at a site excluded from regular monitoring as a wellhead-only well site. The current definition does not include certain pieces of failure-prone

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<sup>29</sup>Attachment B to the commenter's letter (PermianMAP November 2021 Flyover Results).



equipment that could cause large emission events, like natural-gas driven pneumatic controllers and pumps, gas-driven pumpjack engines, and flares.<sup>30</sup> Flares can be located at or near wellhead-only sites and must be clearly encompassed in the definition of major production or processing equipment.<sup>31</sup> The commenter suggests EPA also make clear that the proximity of the major production and processing equipment to the wellhead is not relevant for determining whether a site qualifies for the exemption. The commenter feels that EPA should clarify that major production or processing equipment is at the site if it is associated with the site (*i.e.*, if gas is routed from the wellhead to a nearby flare, that flare is part of the site (unless already part of another affected facility, like a centralized production facility)). Otherwise, the commenter believes the regulations will create incentives to simply locate this equipment farther away from the site.

The commenter (0844-EDF *et al.*) supports EPA's November 2021 Proposal to include a definition of "centralized production facility," which would be subject to fugitive monitoring requirements, and believes this may help eliminate incentives to strategically place equipment to avoid fugitive monitoring requirements. If EPA retains the wellhead-only well site exemption, it should narrow it to apply only to single wellhead sites. Well sites that contain more than one wellhead must not be exempt, since there is no limit to the number of components (and therefore sources of fugitive emissions) that could exist at such sites, even if no associated equipment is present. Even without the addition of associated equipment, a well site with multiple single wellheads could be a significant source of emissions, if there is a very large leak coming from one of the wellheads.<sup>32</sup>

Response I-7-18: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to wellhead only well sites.<sup>33</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

#### 7.1.3.3 Support of Exemption

Comment: Commenters (0797-North Dakota Department of Environmental Quality (NDDEQ) and North Dakota Industrial Commission (NDIC), 0810-The Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) agree with EPA's November 2021 Proposal that wellhead only well sites be excluded from fugitive emissions monitoring based on considerable research and rationale already established in the 2016 NSPS OOOOa rulemaking as well as the 2020 Technical Rule.

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<sup>30</sup>See Part IV.A.2 of the commenter's letter for a full summary of scientific evidence on failure-prone equipment types.

<sup>31</sup> See Attachment B (PermianMAP November 2021 Flyover Results) (finding that low-producing sites had a higher rate of flare malfunctions (31.3%) when compared to higher production sites (9.4%), and that malfunctioning flares at low-producing sites are often completely unlit and venting methane).

<sup>32</sup> Zavala-Araiza (2015), at 8176-8174; Attachment B (PermianMAP November 2021 Flyover Results).

<sup>33</sup> 87 FR 74729-74736 (December 6, 2022).

The commenter's (0797-NDDEQ and NDIC) own experience supports EPA's conclusion that emissions from these sources are "extremely low." The commenters (0797-NDDEQ and NDIC) have only observed a handful of wellhead only well sites with fugitive emissions, and it appears that in those rare cases that the emissions were more a result of operator error. The commenters (0797-NDDEQ and NDIC) believe that the safety risk alone precludes any widespread issue of fugitive emissions from these sites.

Response I-7-19: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to wellhead only well sites.<sup>34</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0577-Kansas Independent Oil & Gas Association (KIOGA)) does not support the November 2021 Proposal that "wellhead only sites" must calculate fugitive emissions. The EPA stated it does not believe these emissions would exceed 3 tpy threshold to require routine monitoring; therefore, it should not impose substantial requirements. Additionally, the small businesses that make up the independent oil and gas industry should not be burdened with purchasing and learning how to operate an OGI device costing approximately \$90,000 to comply with the fugitive emissions requirements at wellhead only sites. The EPA did not evaluate the cost for these small entities to comply with the proposed EG OOOOc; therefore, they should be excluded from applicability.

Response I-7-20: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to wellhead only well sites.<sup>35</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

#### ***7.1.4 Baseline Methane Emissions Calculations***

##### ***7.1.4.1 Request for Clarification***

Comment: Commenter (0749-Petroleum Association of Wyoming (PAW)) claims there are inconsistencies in the method of calculating emissions at the well site. The commenter asks that EPA provide clarification on what methods would be considered acceptable.

Response I-7-21: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii. of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>36</sup>

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<sup>34</sup> 87 FR 74729-74736 (December 6, 2022).

<sup>35</sup> 87 FR 74729-74736 (December 6, 2022).

<sup>36</sup> 87 FR 74724-74736 (December 6, 2022).

Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0446-Artex Oil Company (Artex), 0739-Citation Oil & Gas Corp. (Citation), 0847-Mull Drilling Company, Inc. (Mull), 1085-Small Operator Society LLC (SOS)) requests clarification on the baseline emissions calculation.

The commenter (1085-SOS) states that EPA needs to define the emission production threshold that require inspection (*i.e.*, 3 tpy and above) and make explicit what operations are exempt from routine inspections as well as from what sources count toward that total (*i.e.*, only fugitives, tank battery, both, and/or other equipment).

The commenter (0739-Citation) also asks whether the site level baseline emissions should be based on post-control emissions, post-legally and practicably enforceable limits, actual emissions, pre-control emissions, *etc.*

The commenters (0847-Mull, 1085-SOS) understand that when estimating emissions, the tanks and well are considered a single site. However, the commenters are unsure how to estimate emissions from the tanks and ask for clear and consistent methodology to estimate the emissions from tanks.

Commenter (0446-Artex) states the proposed regulations are duplicative. For example, EPA proposes that the calculation of the baseline methane emission rate should include “each natural gas-driven pneumatic pump, continuous bleed natural gas-driven pneumatic controller...intermittent bleed natural gas driven pneumatic controller...major equipment found in Table W-1B and Table W-1C of Greenhouse Gas Reporting Program (GHGRP) Subpart W [which includes compressors]...[and] each storage vessel tank battery located at the well site.”<sup>37</sup> Each of these identified sources will already be regulated under the proposed NSPS OOOOb; therefore, including these sources artificially inflates the operator's calculation of the baseline emission rate as well as EPA's own estimated emissions reductions used to calculate the cost effectiveness of the November 2021 Proposal.

Response I-7-22: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>38</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0727-OSEE/ODEQ) believes that the proposal that well sites with site-level baseline methane emissions below 3 tpy are not required to conduct OGI monitoring, but are required to perform a survey to confirm if the well site actual emissions are less than 3 tpy appears to be a contradiction within the rule, making it unclear what EPA is proposing. The

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<sup>37</sup> 86 FR 63170 through 63171.

<sup>38</sup> 87 FR 74724-74736 (December 6, 2022).

commenter requests that EPA ensure that the rule text clarifies how facilities should demonstrate the actual emissions are accounted for in the calculation.

The commenter (0727-OSEE/ODEQ) note the ambiguity in EPA's November 2021 Proposal could be read to lead to two possible scenarios, and requests that EPA clarify its intent with respect to the requirements for well sites with site-level baseline methane emissions below 3 tpy. In these scenarios they use OGI as an example but recognize another approved leak detection method could be used.

*Scenario 1:* It can be inferred that the purpose of this demonstration is to require each well site with baseline methane emissions below 3 tpy to conduct an initial survey to find and fix any leaking fugitive emissions components, then no additional OGI monitoring would be required thereafter. If this is EPA's intent, EPA should clearly require an initial survey to be conducted at each well site requesting the exemption for methane emissions below 3 tpy and an additional requirement to fix any fugitive emission leaks within a 90-day timeframe with possible re-monitoring to verify repair of the leaking fugitive emission.

*Scenario 2:* It can be inferred that the purpose of this demonstration is to require each well site with baseline methane emissions below 3 tpy to quantify the emissions from each well site. Additionally, it is unclear whether, if a certain number of leaks are found, the well site would not qualify for this exemption. The tools to quantify emissions using OGI are expensive and time consuming for such a marginal well site, and it is questionable whether this is cost effective compared to any environmental benefit gained. If the purpose of the potential requirement in scenario 2 is EPA's intent, that requirement is unclear and OSEE and the commenter respectfully request EPA clarify the intent behind this requirement.

Response I-7-23: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>39</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0810-Petroleum Alliance-OK) urges EPA to use terminology small oil and gas operators are familiar with without the help of consultants. The lack of plain language and complicated compliance mandates has left many small businesses confused and overwhelmed. The proposal does not use common oil field measurement terminology that operators understand. The EPA's proposed thresholds in tpy do not equate to something understandable or useable by smaller operators without the assistance of hired consultants to conduct emission calculations for each well to make that determination. The commenter requests that EPA propose a rule using terminology that is transparent, understandable, and useable by small oil and gas businesses (preferably production info) so they can easily comply, avoiding the need to hire consultants which will increase the cost of compliance. As an alternative, EPA could

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<sup>39</sup> 87 FR 74724-74736 (December 6, 2022).

develop a matrix or framework that provides smaller operators the option to use in lieu of conducting detailed calculations to determine if the methane emission at their site exceed the proposed thresholds.

Response I-7-24: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>40</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0775-Air Pollution Control Division, Colorado Department of Public Health and Environment (CDPHE), 1267-California Office of the Attorney General (CA AG) *et al.*) state that EPA's approach does not account for equipment failures, which means more sites will fall below the 3 tpy methane emission threshold and will not be required to conduct any monitoring. EPA acknowledges that its approach "assumes all equipment is operating as designed."<sup>41</sup> Also, sites should be required to use the uncontrolled PTE calculation for their storage vessels in their site-level baseline estimate to account for times when these vessels are not operating as designed, which is a known cause of large emission events.

Response I-7-25: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>42</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0573-KDHE) believes that site-specific emissions estimates are the only means to achieve fair and accurate estimates. EPA's staff working on the (triennial) National Emissions Inventory for nonpoint sources has already developed a Microsoft Access-based Oil & Gas Tool, which would be capable of adapting current county-based estimates to well site-based estimates of methane emissions. The commenter strongly recommends that EPA staff developing this rule communicate with EPA Emissions Inventory System staff to see and understand the capabilities of their Oil & Gas Tool.

Response I-7-26: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>43</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

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<sup>40</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>41</sup> 86 Fed. Reg. at 63,171.

<sup>42</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>43</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0938-TXOGA) notes that the time frames in the proposal for calculating methane emissions per site are insufficient to allow operators time to generate accurate calculations. The commenter also requests that EPA specify in any supplemental proposal or final rule that operators who default to performing quarterly OGI at all locations are not subject to recordkeeping requirements related to methane site calculations.

Response I-7-27: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>44</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0938-TXOGA) notes EPA states that it may create a “sliding scale” requirement for OGI monitoring at well sites, which would correlate to PTE for fugitive emissions of the well site.<sup>45</sup> In discussing how to calculate baseline fugitive emissions, EPA notes that the calculation assumes (and has always assumed) that the equipment is operating as designed. This makes sense, of course, because a fundamental principal of determining potential emissions is the “physical and operational design” of equipment.<sup>46</sup> EPA asks whether it should require sites to “use the uncontrolled PTE calculation for their storage vessels in their site-level baseline estimate to account for times when these vessels are not operating as designed, which is a known cause of large emission events of concern.”<sup>47</sup>

Response I-7-28: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>48</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0938-TXOGA) argues treating large emission events as part of the baseline estimate is not appropriate and should not be included in any proposed or final rule. Reducing the incidence and magnitude of large emission events is best accomplished through other means, not by distorting the baseline emissions calculation to sweep into the requirements sources and emissions events that are not appropriately included. This would be similar to assuming that controls are malfunctioning and operating with upsets in determining PTE. The commenter believes that such an approach would distort the baseline calculation in a manner that would make the cost-effectiveness of the rule inconsistent with historic EPA actions and with the facts, in that it would assume very large emissions in the calculation—which are not occurring and may not ever occur—and then take credit for reducing them by sweeping into the

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<sup>44</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>45</sup> See 86 Fed. Reg. at 63,172, tbl. 13, Proposed Well Site Monitoring Frequencies Based on Site-Level Baseline Methane Emissions.

<sup>46</sup> See 40 C.F.R. § 52.21(b)(4) (potential to emit means “the maximum capacity of a stationary source to emit a pollutant under its physical and operational design”) (emphases added).

<sup>47</sup> 86 Fed. Reg. at 63,171.

<sup>48</sup> 87 FR 74724-74736 (December 6, 2022).

requirements sources that otherwise would not be appropriately regulated. While the November 2021 Proposal suggests that altering the baseline calculation methodology would lead to more precise baseline emission calculations, in fact, it would distort the calculation to be less accurate. Other approaches are available to address large emission events and those should be considered and proposed when EPA issues its upcoming proposed action.<sup>49</sup>

Commenter (0938-TXOGA) concludes EPA should not add to the definition of fugitive emission components equipment that is otherwise regulated or controlled by other portions of the subpart.

Response I-7-29: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>50</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

#### 7.1.4.2 Subpart W Emission Factors

Comment: Commenter (0727-OSEE/ODEQ) suggests that instead of owners/operators using default average component counts found in GHGRP to calculate their site-level baseline methane emissions, owners/operators should be allowed to use actual component counts if that data is available. For example, in Oklahoma's point source inventories, facilities provide their actual component counts, which in turn provides better emissions estimates.

Response I-7-30: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach in the December 2022 Supplemental Proposal that does not require owners/operators to calculate their site-level baseline methane emissions. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>51</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0814-Independent Petroleum Association of America *et al.* (IPAA)) states that, unlike other elements of the EPA proposal, the LDAR provisions are based on equipment within the well site. While this concept is appropriate, several key issues need to be understood:

1. The basis for the thresholds,
2. The scope of components that comprise the fugitive emissions baseline, and,
3. The validity of the emissions estimates for the fugitive emissions components.

The commenter (0814-IPAA *et al.*) states EPA's basis for selecting its thresholds is thinly based on assumptions related to the cost effectiveness of its OGI LDAR requirements that are

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<sup>49</sup> In the one instance of which TXOGA is aware in which EPA used uncontrolled emissions as a basis for applicability, the circumstances were narrow.

<sup>50</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>51</sup> 87 FR 74724-74736 (December 6, 2022).

debatable. EPA's scope of components for the fugitive emissions program must be consistent with its other requirements and reflective of the validity of its emissions estimating tools. The commenter believes EPA is correct in excluding individual wells from the well site definition for the LDAR program. EPA should similarly exclude individual wells from its other regulatory requirements. EPA is creating specific requirements for numerous components of the well site. These components should not be included in the fugitive emissions calculations, in part because Subpart W emissions factors would not reflect their emissions. These include pneumatic controllers, pneumatic pumps, and storage tanks.

The commenter (0814-IPAA *et al.*) suggests that before EPA implements these new requirements, particularly for low production existing wells, it must validate its subpart W emissions estimating factors. The subpart W emissions factors were not developed for the purposes for which they are now being used and are based on a limited number of facilities using technology that may be well out of date. It is also structured to reflect both normal and failed equipment operations and thereby includes factors to reflect the fat tail aspect of oil and natural gas production operations.

The commenter (0814-IPAA *et al.*) adds that the emissions factor for intermittent pneumatic control valves is a case in point. EPA is expanding its scope of pneumatic controller regulation in this proposal to include intermittent controllers. Part of EPA's justification for this action is the high Subpart W emissions factor for these controllers. This emissions factor resulted from work by the Gas Technology Institute (GTI). The factor is 13.5 standard cubic feet per hour (scfh). It is based on 19 intermittent controllers most of which were in Canada. Subsequent studies by Oklahoma Independent Petroleum Association (OIPA) (not the Petroleum Association of Oklahoma) and EPA of intermittent controllers, many of which were on low production wells have produced emissions factors far lower than the Subpart W factor – 0.4 scfh (OIPA) and 0.32 scfh (EPA). Yet, EPA still uses the GTI factor for the subpart W GHG reporting and presumably for its proposed emissions calculations justifying its new proposal.

The commenter (0814-IPAA *et al.*) adds that millions of dollars will be spent on compliance with these LDAR requirements (and on replacement of intermittent pneumatic controllers). The requirements should not impose these costs when the environmental benefits are specious. Among the most vulnerable operations to be burdened by these regulations will be low production wells – the primary target of the environmental groups determined to “keep it in the ground.” Recent work for a DOE Report shows that the low production wells that it measured and evaluated would overwhelmingly fall below the EPA proposed 3 tpy threshold. It is imperative that EPA's subpart W emissions factors are as accurate as these field tests.

The commenter (0814-IPAA *et al.*) notes that EPA offers no explanation or justification that the total site-wide calculations be re-calculated every time “equipment” is added or removed from the site. The commenter believes this calculation is unjustified with no environmental benefit.

Commenter (0577-KIOGA) requests clarification on how to calculate the emission factors to determine the level of methane emissions for leak monitoring frequency and to determine the GHG standards for well sites shown in Table 3 at 86 Fed. Reg. 63121. The EPA has stated that



the GHG emission factors in 40 CFR 98, Subpart W were to be used and not the emission factors in EPA-453/R-95-017 [Protocol for Equipment Leak Emission Estimates].

Response I-7-31: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>52</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

#### 7.1.4.3 Repeating Calculation When Equipment is Added/Removed

Comment: Commenter (0446-Artex) states EPA has not provided clear mechanisms for revising the required LDAR monitoring frequency based on changes to the baseline methane emission rate. EPA proposes that “this calculation would be repeated every time equipment is added to or removed from the site”<sup>53</sup> but does not explicitly explain how this repeated calculation would be used to revise the site’s applicable LDAR monitoring frequency. Without explicit “off-ramp” provisions for performing this analysis, state and local agencies implementing EPA’s proposed rule could invoke “anti-backsliding” principles to require that a site continue implementing LDAR monitoring at the frequency established based on the initial calculation of the baseline methane emission rate. In this case, EPA’s proposed requirement that the calculation be “repeated every time equipment is added to or removed from the site”<sup>54</sup> would constitute a meaningless paperwork exercise ostensibly occurring ad infinitum for even the smallest of routine maintenance and replacement activities at a given site.

Response I-7-32: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>55</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

#### 7.1.4.4 Large Events/Malfunctions/Abnormal Process Emissions

Comment: Commenter (0844-EDF *et al.*) supports EPA using site-specific baseline emission calculation to categorize sites. However, as proposed, the site-level estimates still fail to fully characterize site-level emissions because they do not account for super-emitter and abnormal process emissions. These categories of emissions are particularly prevalent and problematic in the production segment, representing more than 70 percent of total emissions.<sup>56</sup> Adopting the

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<sup>52</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>53</sup> 86 FR 63170.

<sup>54</sup> *Ibid.*

<sup>55</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>56</sup> Alvarez 2018.

following recommendations will help ensure sites fall into representative emission tiers and are subject to the appropriate frequency of monitoring:

1. Use emission factors that account for malfunctions,
2. Use uncontrolled emissions for tanks, and
3. Estimate emissions from all potentially emitting onsite equipment such as flares in the calculation.

The commenter (0844-EDF *et al.*) agrees with EPA that its previous model plant approach, which divided well sites into production-based categories and then assigned average estimated component and equipment counts to derive emissions, did not capture actual well site component and equipment counts, particularly at more complex facilities.<sup>57</sup> It was also not representative of well site emissions because it relied on emission factors that do not account for large emission events and because it tended to underestimate average onsite equipment counts.<sup>58</sup> The commenter believes EPA has correctly recognized the flaws in this approach, as well as in those that assume leak rates are well correlated with production levels.<sup>59</sup>

The commenter (0844-EDF *et al.*) notes however, EPA's proposed approach, suffers from flaws that will cause underestimating of actual emissions, shortcomings that are especially problematic when operators rely on the calculation to determine the required frequency of inspections for a particular site. The commenter recommends that EPA revise the site-level calculation methodology to account for super-emitters and equipment failures, rather than using the proposed PTE calculation described in the proposal preamble.<sup>60</sup>

The commenter (0844-EDF *et al.*) adds that another issue with the proposed approach is that it allows operators to estimate site-level emissions on the assumption that any control equipment will be 100 percent effective 100 percent of the time. This assumption does not reflect reality and ignores countless field observations of the repeated failure of control equipment that leads to large emission events, especially those associated with tanks.<sup>61</sup>

The commenter (0844-EDF *et al.*) notes that the proposed approach does not require operators to calculate potential emissions from all of the emitting equipment onsite, only a subset. Flares are an example of a commonly malfunctioning piece of equipment that can cause major emission events is totally left out of consideration in EPA's proposed site-level emission calculation. A representative site-level emission calculation cannot exclude potential emissions from any equipment located at the site.

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<sup>57</sup> Attachment F (ICR analysis).

<sup>58</sup> *Id.*

<sup>59</sup> 86 Fed. Reg. 63187; see also Lin et al., Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin, 11 *Sci. Reports* 22291 (2021), <https://www.nature.com/articles/s41598-021-01721-5> (finding a steady leak rate of 6-8% over six years in the Uinta Basin even as production declined and attributing high leak rate in part to the abundance of low producing wells in the basin).

<sup>60</sup> 86 Fed. Reg. 63171.

<sup>61</sup> See Attachment B (PermianMAP November 2021 Flyover Results); see also Part IV.A.1.

The commenter (0844-EDF *et al.*) states if PTE is supposed to represent the theoretical PTE, then in most cases, a well site's PTE is equivalent to its entire methane production (*i.e.*, natural gas production adjusted by methane content). For example, if there is a malfunction that causes 100 percent of the gas production to vent, such as a stuck separator dump valve, then the site's emissions are equivalent to its methane production. In rare cases, a site's emissions may even exceed production, such as an over-pressurized gathering system venting at an upstream tank. EPA's proposed calculation using subpart W methods and assuming controls are working does not, in fact, calculate PTE, but rather the possible baseline emissions of a site that is operating without any malfunctions whatsoever on a continuous basis. Numerous research studies have shown that this approach underestimates average emissions due to malfunctions.

Response I-7-33: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>62</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0814-IPAA *et al.*) asserts that baseline emissions calculations should be representative of normal operations, not large emissions events. The EPA seems to allow for sites with calculated baseline emission less than 3 tpy be exempt from surveying obligations and then makes every effort to make it such no sources will be able to demonstrate baseline emission below 3 tpy. To the extent low production wells are required to calculate baseline emission, the calculation should be a calculation of fugitive emissions, *i.e.*, leaks.

Response I-7-34: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>63</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

#### 7.1.4.5 Alternatives to Baseline Emissions Calculation

Comment: Commenter (0564-Arkansas Independent Producers & Royalty Owners (AIPRO)) believe baseline emissions for triggering LDAR survey frequency should be based on fugitive emissions only as defined by the fugitive emissions in 40 CFR 60, subpart OOOOa rather than the November 2021 proposal which includes all emissions sources/types in the baseline determination.

The commenter (0564-AIPRO) proposes that operators should be allowed to utilize the results of historical LDAR surveys to determine its baseline fugitive emissions PTE, rather than being required to use the component count methodology established in subpart W. Many operators have well sites already enrolled in an LDAR program that have established a low leak rate. Forcing these sites to utilize the component count methodology to calculate fugitive PTE while

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<sup>62</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>63</sup> 87 FR 74724-74736 (December 6, 2022).

possessing real world data is not practical. Utilizing site-wide methane emissions from all sources (process emissions, manual tank venting, process emissions, *etc.*) not just fugitive emissions, is not practical, overly burdensome, not cost-effective and, most importantly, will not accomplish meaningful fugitive emissions reductions, in the commenter's opinion.

The commenter (0564-AIPRO) states that 40 CFR subpart W, EPA's GHGRP, allows for adjusted emission factors based on the most recent LDAR survey conducted at the location, when done either voluntarily or as required by federal, state, tribal, or municipal regulation. In many instances this emission total is less than the calculated numbers based on emissions factors. Given that the LDAR survey calculation is more representative of the actual emissions at the location, it would only make sense to be able to have the option to use those numbers in determining the baseline fugitive emissions for a location.

Response I-7-35: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>64</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0938-TXOGA) believes that it is not necessary for EPA to propose a new methodology for determining site-specific emissions estimates. Rather, EPA should incorporate the emission calculation methodologies used for 40 CFR part 98, subpart W compliance into its proposed and final rules, to promote consistency between the NSPS and the current GHG reporting requirements under subpart W and greater accuracy in generating emissions estimates. For owners/operators that are already subject to mandatory GHG reporting under subpart W, any new approach to developing site-specific emissions estimates would create additional burden without commensurate benefit and, perhaps more importantly, confusion for sources calculating site-specific emissions under both programs.

Response I-7-36: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>65</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0739-Citation, 0777-Ascent Resources, LLC (Ascent)) argue that fugitive monitoring requirements based on emissions calculations is improper.

The commenter (0777-Ascent) argues the EPA should base the frequency of fugitive monitoring requirements under the NSPS and existing source guidelines on the level of methane emissions from sources and equipment that will be subject to the fugitive monitoring program. The commenter requests that EPA not use "site level methane baseline emissions" but rather site-level baseline fugitive emissions, based on the calculated emissions rates from the fugitive

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<sup>64</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>65</sup> 87 FR 74724-74736 (December 6, 2022).

components that will be subject to the fugitive monitoring program. It would be arbitrary to base the intensity of fugitive monitoring requirements on emissions calculations that do not reflect the number and type of fugitive components at a site, when those fugitive-specific emissions calculations are readily available.

The commenter (0739-Citation) similarly states fugitive monitoring requirements should be based on a facility's potential for fugitive emissions, not from emissions associated with engines, dehydrators, venting, storage tanks, *etc.* Fugitive emission monitoring will have no effect on emission rates other than on fugitive emissions.

Response I-7-37: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>66</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) believes EPA should require operators to calculate site-level baseline emissions using more accurate emission factors, like the averaged emission factors from Rutherford *et al.* The Rutherford tool provides equipment-level emission factors that are calculated by summing component-level emission factors according to estimated component counts per piece of equipment using methods described in Section 3.3 of the study and Section 5.2 for the GHG Inventory (GHGI).<sup>67</sup> These emission factors, derived from numerous recent peer-reviewed studies, will estimate site-level emissions more accurately than EPA's subpart W factors.

Response I-7-38: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>68</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0775-CDPHE, 0844-EDF *et al.*) question EPA's claims that the proposed quarterly monitoring at sites from 3 tpy to 8 tpy is more stringent than Colorado regulations.<sup>69</sup> EPA fails to account for the significant differences in actual coverage that result

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<sup>66</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>67</sup> *Id.* at 11-12.

<sup>68</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>69</sup> 86 Fed. Reg. 63,192. EPA's comparison uses a site-level VOC-to-methane ratio of 0.28 to compare the 3 tpy methane threshold to the Colorado's VOC tiers, but tanks typically have a much higher VOC-to-methane ratio, which EPA's analysis does not take into account. This is particularly important since Colorado regulations are based on tank emissions when tanks are present.

from using a different site-level emission calculation. Furthermore, Colorado recently updated its regulations, increasing monitoring frequencies and requiring regular monitoring at all tiers.<sup>70</sup>

Commenter (0844-EDF *et al.*) notes Colorado uses an uncontrolled tank emission calculation that is more representative of real site conditions.<sup>71</sup> This calculation still does not account for issues like unlit flares and stuck separator dump valves, but it is more representative of a site's actual potential emissions. The commenter states this approach still greatly underestimates actual site-level emissions because it does not account for most equipment failures and relies on outdated emission factors. However, it is directionally an improvement from EPA's proposed PTE calculation because it uses uncontrolled tank emissions, and tanks are the largest source of fugitive and abnormal process emissions by most estimates.

Commenter (0775-CDPHE) states EPA's calculations and claims that the proposed thresholds are much more stringent than Colorado's are based on the inappropriate assumption of 0.28 VOC: methane (by weight) in tank emissions. The commenter provides further information in their comment letter on why this assumption is inaccurate. In the commenter's estimation, the VOC emissions associated with a methane emission rate of 3 tpy from storage tanks equates to 32.7 tpy VOC, not 0.83 tpy VOC. At the threshold of 32.7 tpy VOC, Colorado is already requiring at least quarterly monitoring.

Commenter (0844-EDF *et al.*) replicated EPA's PTE analysis based on the Enverus 2019 well pads, using average component emissions per site, GHGRP tank emission factors, and a Monte Carlo simulation for pneumatic pump and pneumatic controller emissions.<sup>72,73</sup> The commenter was able to predict the number of sites above and below the proposed 3 tpy threshold. From this analysis, they were able to assign each site to an inspection frequency under the new Colorado regulations (annual for >0 and =2 and ≤50 tpy VOC, and monthly for >50 tpy VOC).<sup>74</sup> Under Colorado regulations, emissions are calculated using actual uncontrolled tank emissions (based on state-specified emission factors). If a site does not have a tank, the calculation is based on the site-wide actual controlled VOC emissions. Another commenter (0775-CDPHE) believes that

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<sup>70</sup> 5 Colo. Code Regs. § 1001-9, Pt. D, § II.E.4,  
[https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn\\_Z0x50X/view](https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view).

<sup>71</sup> 5 Colo. Code Regs. § 1001-9, Pt. D, § II.E.4.e,  
<https://drive.google.com/file/d/1ZwPwoAHVWEoRmPhoa11UNEiP-RC9ZpI7/view>.

<sup>72</sup> In order to recreate the site level dataset used by the EPA in their analyses, we first downloaded well level characteristic and production data for all wells with production in 2019 from Enverus Prism. We removed offshore wells by excluding Enverus Basin "GOM Offshore", Enverus State "CAO" and a series of counties designated as offshore (see API State and County Codes). After speaking with Enverus regarding their methods for creating their pad identifier, we identified an issue of exceptionally large pads (>25,000 active wells) created through their spatial model. Enverus is currently working to resolve this issue, and is open to feedback on a more accurate model. As a preliminary step, EDF decided to disaggregate sites by operator in order to split identified pads with more than one operator. This led to the creation of ~4,000 more pads from the original dataset (~.5%). To determine low-producing sites we calculated site level BOE produced per day and selected those below 15 BOEpd.

<sup>73</sup> Attachment G (Lyon PTE Analysis).

<sup>74</sup> For simplicity, we ignored differences for sites in proximity to occupied areas or in disproportionately impacted (DI) communities. This is a conservative comparison because many sites in Colorado are subject to more frequent inspections than in our simplified analysis.

EPA should permit states to use VOC emissions as a proxy for comparing the stringency of a state program with EPA's proposed thresholds.

Commenter (0844-EDF *et al.*) states Colorado's site-level calculation more accurately predicts actual emissions and therefore places sites in more accurate monitoring tiers. Because EPA's proposed calculation will underestimate actual emissions in the vast majority of cases and fails to account for the well-documented problem of abnormal emission events caused by equipment failures, the commenter recommends EPA revise the calculation by 1) employing emission factors that account for malfunctions, 2) using uncontrolled tank emissions, and 3) ensuring that every piece of equipment at the site, including flares, is included in the calculation.

Response I-7-39: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>75</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0437-New York Office of the State Comptroller (NYOSC), 0756-Baker Hughes, 0788-350 Seattle) believes that the total site-wide emission baseline should be measured, rather than calculated.

The commenter (0756-Baker Hughes) is of the opinion that emissions factors are often inaccurate as applied to a given site and cannot capture the normal variation between different sites. Nor does this approach account for the age of equipment, variation in gas quality (wet, dry, sweet, sour, *etc.*), or provide a means of assessing the likelihood and impact of large emission events. Only by direct measurement can an appropriate and effective baseline be determined.

The commenter (0437-NYOSC) urges EPA to take measures to ensure accurate assessment of methane emissions using empirical data rather than factor-based estimates.

The commenter (0788-350-Seattle) believes that a rule based on a PTE calculation may allow thousands of wells to avoid regular monitoring. The commenter agrees with the testimony of Natural Resources Defense Council's Lissa Lynch in calling for the removal of this loophole for smaller wells.

Response I-7-40: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>76</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

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<sup>75</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>76</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0785-John Crane Inc.) recommends that the site-level methane baseline emissions are open to be derived from population-based emission factors or from surveys, based on the owner or operator's preference. The sites will require some frequency of surveys regardless of the baseline calculation; therefore, some operators may choose to perform the survey at once (and instead of a calculation) and consider it a part or whole of their annual survey requirements. The commenter recommends that the EPA foster the exploration and use of a variety of measurement and monitoring system technologies appropriate for the region and conditions for which they are being deployed to ensure optimal efficiency and accuracy of results.

Response I-7-41: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>77</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0737-Clarke Valve) believes that valves that are part of such production and processing equipment should continue to be included in a site's baseline emissions. More specifically, stem fugitive emissions from control valves should be part of a site's baseline emissions. The commenter encourages EPA to continue allowing EPA Method 21 to be used to calculate baseline emissions at oil and gas sites.

Response I-7-42: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>78</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0446-Artex) states EPA is proposing "site-specific emissions estimates based on the number and type of equipment located at the individual site to determine the monitoring frequency." EPA acknowledges that these types of equipment include pressure relief valves (PRVs) and pneumatic controllers which are both integral to the safe design and operation of a well site. Establishing LDAR applicability on the basis of the number of these critical safety components effectively encourages owners and operators to forego the installation of PRVs and pneumatic controllers in an attempt to achieve baseline methane emission rates below the 3 tpy threshold. The possibility of catastrophic equipment failure motivated by these attempts to avoid LDAR applicability would pose a far greater risk to human health and environmental protection than the risks mitigated by EPA's November 2021 Proposal.

Response I-7-43: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. This approach proposed that the equipment located at

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<sup>77</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>78</sup> 87 FR 74724-74736 (December 6, 2022).



the site would be the basis for determining the fugitive emissions monitoring requirements, in lieu of using the self-reported baseline emissions as a threshold proposed in November 2021. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>79</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

#### **7.1.5 Well Sites with Baseline Emissions <3 tpy**

Comment: Commenters (0195-Evangelical Environmental Network (EEN), 0201-Sierra Club, Lone Star Chapter (Sierra Club-LSC), 0391-KBIC, 0401-Mercy Investment Services, Inc. (Mercy), 0421-Big Thicket Biosphere Reserve (BTBR), 0434-Impax Asset Management, LLC (Impax), 0448-As You Sow (AYS), 0435-Wespath Benefits and Investments (Wespath), 0455-RDN, 0460-Trinity Health, 0560-Legal & General Investment Management America, Inc. (LGIM America), 0586-Navajo EPA, 0589-NEI Investments (NEI), 0753-Institute of Governance & Sustainable Development (IGSD) and Center for Human Rights and the Environment (CHRE), 0757-Private Equity Stakeholder Project (PESP), 0781-NTAA, 0807-BP America Inc. (BP), 0812-Ohio Farmers Union (OFU) *et al.*, 0844-EDF *et al.*, 0931-Essential Information, Inc. (Essential), 0937-Fort Berthold POWER) agree that well sites with baseline emissions below 3 tpy should be required to report emissions. Some commenters believe EPA's proposed reporting requirements suffice while others argue for more stringent requirements.

Commenters (0195-EEN, 0201-Sierra Club-LSC, 0391-KBIC, 0586-Navajo EPA, 0753-IGSD/CHRE, 0757-Private Equity Stakeholder Project, 0775-CDPHE, 0781-NTAA, 0844-EDF *et al.*) believe well sites less than 3 tpy should be required to conduct quarterly or at least regular monitoring for leaks, particularly where leak prone equipment is present on the site. The commenter (0201-Sierra Club-LSC) requests that EPA should go further and require monthly LDAR for wells and compressor stations.

Commenter (0837-Clean Water Action (CWA) *et al.*) requests that EPA increase monitoring and inspection for smaller, high polluting wells.

Commenters (0753-IGSD/CHRE, 0775-CDPHE) argue the EPA should follow Colorado's lead and require monitoring of all wells.<sup>80</sup> Further, Colorado's program, which has formed the basis

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<sup>79</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>80</sup> CDPHE, Air Quality Control Commission Regulation Number 7: CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS (EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES), (2021), 1-404, 287 ("Well production facilities' are also subject to LDAR requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The 'owned, operated, or leased' qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from 'well production facility' and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells."); See also Environmental Defense Fund (17 Dec. 2021) With Powerful New Oil and Gas Rules, Colorado Sets Bar for Nation-leading Protections, Press Release ("Today the Colorado Air Quality Control Commission voted unanimously to adopt landmark rules limiting oil and gas methane and air pollution. The rules will require frequent inspections for all

for many other LDAR programs around the country, including EPA's, should continue to be found equivalent to EPA's LDAR program, without the need for an overly complicated and technical comparison of the proposed thresholds. Grouping small, potentially leak-prone wells into LDAR requirements sets Colorado closer to achieving the state's environmental justice law (HB21 – 1266), which calls for a 60 percent reduction in greenhouse gas emissions by 2030.<sup>81</sup>

The commenter (0753-IGSD and CHRE) notes that exempting sources below 3 tpy from monitoring would ignore the risks these wells represent and the threat that these sources could become large emitters, or that collectively, they might nonetheless represent significant emissions.

The commenters (0605-Muscogee (Creek) Nation, 0833-Ute EPD, 0943-Sault EPD) argue that simply because a well site has lower estimated emissions does not mean that the equipment will not malfunction or fail resulting in significant emissions. These leaks and malfunctions must be identified and addressed as soon as possible to avoid emission of VOC, methane, and HAP. A single inspection after the rule is finalized will not address this problem, in the commenters' opinion.

The commenter (0201-Sierra Club-LSC) states EPA must remove the LDAR exemption for well sites that have a calculated PTE below 3 tpy of methane. Under the proposal, these wells need only conduct one LDAR inspection to fulfill their obligations; the commenter wants them to be subject to no less stringent LDAR requirements than all other wells. At a minimum, if EPA insists on including some form of relaxed LDAR standards for less complex wells, it must limit that exemption more than it has done in the proposal. For instance, EPA could require regular LDAR at all well sites that have certain kinds of malfunction-prone equipment (like storage vessels and separators), even if they otherwise fall below the 3 tpy threshold. Other possibilities also exist as well to limit this exemption.

The commenter (0195-EEN) indicates that the proposed standards in the rule would be strengthened by incorporating quarterly LDAR inspection of all wells with 2 tpy or more. This recommendation is based on the EPA's own conclusion in the November 2021 Proposal, which states: "...sites with total baseline methane emissions of 2 tpy, the commenter concludes that regular monitoring at semiannual or quarterly frequencies would be cost-effective." Based on this conclusion that quarterly inspection of well sites with 2 tpy is cost-effective, the commenter recommends that the 3 tpy emissions threshold in the November 2021 Proposal be reduced to 2

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wells, including smaller, leak-prone ones which have been shown to be responsible for an outsized share of emissions. In addition, the rules will prohibit venting of methane during maintenance activities.").

<sup>81</sup> Boulder County (17 Dec. 2021) Air Commission strengthens oil and gas leak repair requirements, but fails to ensure Colorado will meet its climate goals (last visited 5 Jan. 2022) ("The new regulations will move Colorado towards the targets set by a 2021 environmental justice law (HB21-1266), but the state will fall short of the goal of 60 percent reductions by 2030. Additional emissions reductions will still be needed to meet that goal. HB21-1266 also requires these regulations to provide extra protections for communities that are disproportionately impacted by oil and gas pollution, as well as by climate change. The rules adopted today do require more frequent inspections and repairs at sites near where people live, work and play. But some provisions do not extend to disproportionately impacted communities statewide — only in the ozone-impacted Front Range.").

tpy emissions and that the frequency of inspections be increased to quarterly. The commenter recommends that sites below 2 tpy be inspected at least annually.

The commenter (0937-Fort Berthold POWER) states all wells, regardless of their PTE should have monthly LDAR inspections. The commenter's community is directly impacted by the toxic pollutants that are emitted alongside methane and the commenter is also facing the terrible consequences of these greenhouse gases being emitted by the effects of global warming.

Commenter (1330-Catskill Mountainkeeper) suggests requiring monthly leak inspections at all wells and compressor stations and eliminate exemptions for smaller, high polluting and leak-prone wells, including for wells that produce less than 3 tpy of emissions (or, alternatively, consider mandating continuous monitoring with real-time reporting, which may be cost-effective at many sites and allow earlier detection and enforcement).

Response I-7-44: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>82</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0401-Mercy, 0434-Impax, 0435-Wespath, 0448-AYS, 0455-RDN, 0460-Trinity Health; 0589-NEI; 0757-PESP; 0812-OFU *et al.*, 0931-Essential) believe that the EPA's November 2021 Proposal standards for oil and natural gas methane emissions are an important step in the right direction, and urge the EPA to ensure strong methane emission performance standards by crafting a regulation that includes all potentially significant sources of methane emissions, including smaller leak-prone wells, under emission standards.

The commenter (0757-PESP) believes that rigorous monitoring requirements that reduce emissions by 80 to 90 percent must apply comprehensively across all facilities, including wells below 3 tpy. These PTE calculations are based on emission factors that very likely underrepresent the true extent of fugitives originating from these wells, and do not account for equipment failures or malfunctions that can lead to super-emitting events. Furthermore, marginal wells are mostly owned by larger companies that have the capacity to ensure compliance. Thus, EPA should not provide special and more lenient requirements for these wells, but should mandate regular monitoring at all wells, regardless of their calculated PTE.

The commenter (0931-Essential) strongly opposes the lack of emissions monitoring at small oil and gas wells under the proposed rules. The commenter states if equipment breaks or is not functioning as intended, significantly greater amounts of methane emissions could be leaking from these small wells for years. It would fall on state air control agencies to catch problems. However, air control agencies are only required under federal guidelines to conduct regular Full Compliance Evaluations, Partial Compliance Evaluations, and Investigations for Title V major emitter sources, and for synthetic minor sources with potentials to emit 80 percent of Title V

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<sup>82</sup> 87 FR 74724-74736 (December 6, 2022).

major emitter thresholds.<sup>83</sup> Thus, the commenter says that smaller well sites have no federally-mandated inspection schedule and fugitive emissions problems may be ongoing for years with no plan for government intervention. Even if a state inspector happened to visit a small well, he/she would not be likely to do OGI monitoring and so could miss the fugitive emissions problems, unintentionally allowing methane leaking to be chronic.

The commenters (0589-NEI, 0931-Essential) argue if owners have the resources to invest in the building and operating of these small wells, they surely have the resources to conduct a site visit twice a year to check for fugitive methane and VOC emissions. Furthermore, it is presumably in their interest to visit wells occasionally to ensure that they are operating at maximum efficiency to obtain good returns on investments. Thus, the commenters do not think it can be convincingly argued that bi-annual inspections for fugitive emissions is an undue burden on an owner. The commenter (0931-Essential) recommends a minimum of semiannual OGI monitoring for all well sites with total site-level baseline methane emissions less than 3 tpy.

Response I-7-45: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>84</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0421-BTBR)) says that currently the EPA monitors methane emissions from industries in the Beaumont/Port Arthur area including a number of high polluting facilities, such as Valero and Oxbow Calcining. Under the current rule, the EPA allows operators to calculate lower potential polluting emissions (less than 3 tpy) that can escape regular leak detection. The Texas Commission of Environmental Quality (TCEQ) Emissions Event database indicates that tons more sour gas is released annually through flaring. Moreover, flaring releases sulfur dioxide, which likely contribute to exceedances of the EPA's health-based sulfur dioxide National Ambient Air Quality Standard (1-hour standard) for Jefferson County, Texas.

Response I-7-46: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>85</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) supports the November 2021 Proposal's requirements for quarterly OGI monitoring at well sites and tanks batteries, but the commenter urges the Agency to finalize stronger standards that require quarterly monitoring at all sites with potentially significant emissions including smaller sites below 3 tpy. If EPA retains the tiered

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<sup>83</sup> EPA Office of Enforcement and Compliance Assurance, Oct 4, 2016. Clean Air Act Stationary Source Compliance Monitoring Strategy of October 2016. EPA Online. Accessed Jan 20, 2022: <https://www.epa.gov/sites/default/files/2013-09/documents/cmsspolicy.pdf>, pp. 6-12.

<sup>84</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>85</sup> 87 FR 74724-74736 (December 6, 2022).

structure, it should categorically exclude sites with failure-prone equipment from any tier subject to less frequent monitoring. The commenter also urges EPA to increase monitoring frequencies at the largest sites where potential emissions are very high and monitoring is highly cost-effective.

The commenter (0844-EDF *et al.*) states to remedy the numerous problems inherent in allowing smaller sites to forgo regular monitoring, EPA should eliminate the 3 tpy tier and require quarterly monitoring at these sites, particularly if it retains the wellhead only exemption.<sup>86</sup> Quarterly monitoring is effective at reducing emissions and can be conducted at low cost at all sites. If EPA retains the tiering structure, it should exclude sites with known high-emitting equipment from any low-PTE category because of the potential for failure that could lead to major emission events. Numerous studies show that tanks, separators, flares, and gas-driven pneumatics commonly fail and lead to significant emissions.<sup>87</sup> EPA should categorically exclude any site with this type of equipment from qualifying for an exemption from routine monitoring through a low-PTE calculation. This would also streamline the rule's compliance and enforcement process because operators and inspectors could automatically eliminate certain well sites from qualifying for the exemption from regular monitoring simply by observing that certain kinds of equipment were present at the site, rather than having to calculate and verify PTE for those sites. Under their first approach, the commenter replicated EPA's PTE analysis. Following EPA's methods using 2019 Enverus Prism data and subpart W methods, the commenter estimates that the 3 tpy threshold would exempt 20 percent of well sites (48 percent of oil wells and 19 percent of gas wells) from regular monitoring, forgoing up to 330,000 tons of methane reductions.<sup>88</sup> These 20 percent of wells comprise 14 percent of fugitive emissions, in line with what EPA estimates in the rule.

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<sup>86</sup> See, e.g., CARB, Oil and Gas Methane Regulation 2019 Annual LDAR Summary (Nov. 2021) <https://ww2.arb.ca.gov/sites/default/files/2022-01/CARBOilandGasMethaneRegulation2019AnnualLDARSummary-Revised.pdf> (requiring quarterly monitoring regardless of site-level emissions potential).

<sup>87</sup> See Part X, Subsection A *infra*; Zavala-Araiza et al., Toward a Function Definition of Methane Super-Emitters: Application to Natural Gas Production Sites, 49 *Env. Sci. Tech.* 8167 (2015), <https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b00133>; Lyon, D. R. et al. Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites, 50 *Env. Sci. Tech.* 4877–4886 (2016) (finding that emissions from tank vents and hatches accounted for roughly 90% of all detected hydrocarbon sources emitting >3–10 kg per hour. Other sources observed included separator pressure relief valves, dehydrators and flares.); Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 *Nature Comms.* 4715 (2021), <https://www.nature.com/articles/s41467-021-25017-4#citeas> (Figure 3 shows tanks as the largest emission source and biggest reason for disagreement with GHGI data. It also shows that flare methane emissions are underestimated in the GHGI and shows pneumatics and separators as large sources.); Zavala-Araiza et al., Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 *Nature Comms.* 14012 (2017), <https://www.nature.com/articles/ncomms14012>; Tyner & Johnson, Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, 55 *Env. Sci. Tech.* 9773 (2021) <https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572> (“More than half of emissions were attributed to three main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%).”); Lyman et al., Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells, 7 *Elementa. Sci. of the Anthropocene* 43 (2019), <https://doi.org/10.1525/elementa.381> (“The majority of observed emission plumes were from liquid storage tanks (75.9% of all observed plumes), including emissions from pressure relief valves and thief hatches on the tank or from piping that connects to the tank. Well pads with control devices to reduce emissions from tanks (combustors or vapor recovery units) were more likely to have detected emissions.”).

<sup>88</sup> Attachment G (Lyon PTE analysis).

As a second approach to estimating the 3 tpy threshold, commenter (0844-EDF *et al.*) used GHGRP data, extrapolated nationwide and disaggregated to the site level. First, GHGRP data were analyzed with a statistical model that uses production data and reported basin-level emissions to estimate county-level emissions from both reporters and non-reporters. Then, facility-level emission estimates were disaggregated down to an individual site level based on that site's percentage of the whole facility's production. This method of disaggregation likely overestimates emissions at lower production sites, which may not have all of the equipment found at larger sites. This method predicts that close to 70 percent of sites will be below the 3 tpy threshold, comprising 21 percent emissions. These first two methods likely approximate ways in which operators will estimate their own PTE. However, measurement studies have shown that these "bottom-up" approaches can significantly underestimate emissions at a site. Therefore, the commenter also performed the analysis using measured site-level emission factors.

For the third approach, commenter (0844-EDF *et al.*) used the site-level emissions factors (weakly correlated with production) from Alvarez *et al.* to predict site-level emissions.<sup>89</sup> Comparing these site-level emissions estimates to the 3 tpy threshold, the commenter estimates that about 14 percent of sites are actually under a 3 tpy threshold, but that these sites only comprise around 1 percent of fugitive emissions. This method may overestimate emissions at some of the smaller, low-equipment site since emission factors aren't able to distinguish between sites with significant equipment and sites with very little equipment.

The commenter (0844-EDF *et al.*) continues, the fourth approach represents a hybrid: calculating whether a site is above or below the 3 tpy threshold using the GHGRP emissions approach, but then calculating the percentage of site and fugitive emissions under that threshold using the Alvarez site-level emissions. This column approximates the potential impacts of operators using a PTE approach but having site-wide emissions in line with what Alvarez *et al.* found. This approach finds that the roughly 70 percent of sites below the 3 tpy threshold comprise about 40 percent of fugitive emissions.

The commenter (0844-EDF *et al.*) finds these methods demonstrate that it is difficult to predict exactly what percentage of emissions are left unmitigated by the 3 tpy threshold, but that it is likely to be substantial. Uncertainty around the number of sites that could be allowed to forgo regular monitoring and the magnitude of emissions potentially forgone strongly weigh against EPA finalizing the November 2021 Proposal's approach to sites below 3 tpy. The commenter argues EPA should not finalize a loophole for sites below 3 tpy because doing so could leave sites responsible for up to 43 percent of fugitive emissions inadequately monitored. To look at this another way, if EPA finalizes its LDAR program as proposed and includes a one-time only inspection frequency for well sites under 3 tpy, their analysis shows this could reduce the overall effectiveness of its LDAR program by as much as half and leave millions of tons of pollution unaddressed. This one-time monitoring loophole thus significantly undermines the effectiveness of not just the fugitive monitoring program, but the entire November 2021 Proposal.

The commenter (0844-EDF *et al.*) goes further, the November 2021 Proposal's loophole is not supported by cost considerations, scientific evidence of emissions from smaller sites, or any

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<sup>89</sup> Alvarez 2018.

small business concerns. Leaving such a significant portion of easily achievable emission reductions on the table that could be cost-effectively cut is illogical and goes against EPA's directives under the CAA, the Congressional Review Act Resolution (which, in practice, effectively nullified the low-production well exemption), and Executive Order 13,990. Forgoing these emission reductions will make it much more difficult for the Administration to meet its climate commitments made in Glasgow at the 26th United Nations Climate Change Conference of the Parties and under the Global Methane Pledge. It will also cause serious enforceability and compliance issues, setting up gamesmanship and creating room for inaccurate interpretations of regulatory obligations. Further, the November 2021 Proposal's loophole raises serious environmental justice concerns that undercut the Administration's commitment to protecting frontline communities from the disproportionate burdens of pollution. Last, exemptions for low-utility sites allow operators to neglect maintenance and disincentivize proper closure, potentially exacerbating the orphan well problem.

The commenter (0844-EDF *et al.*) states while the November 2021 Proposal's one-time monitoring requirement differs from the low-production or marginal well exemption for new sources finalized under the last Administration, the commenter expects the universe of sites falling into each category to be very similar.<sup>90</sup> The 3 tpy category does not include all low-producing or marginal sites (*i.e.*, those producing an average of less than 15 BOE/d), but it will likely exempt hundreds of thousands of sites from regular monitoring. Marginal sites tend to have less equipment onsite, and therefore will calculate low potential emissions using EPA's proposed PTE calculation.

Related to the flaws in EPA's November 2021 Proposal's PTE calculation for operators (discussed above), commenter (0844-EDF *et al.*) thinks EPA's analysis estimating the number of sites and amount of emissions potentially falling below 3 tpy is flawed. The commenter's attempt to recreate this analysis, which is outlined in EPA's Appendix A, revealed multiple problems, and the commenter believes it is unsuitable for estimating sites' PTE.<sup>91</sup> First, well site equipment counts, which are key inputs to the fugitive emission calculations, are applied randomly and do not account for likely relationships between production and equipment counts. Similarly, pneumatic controller and pump counts are assigned randomly even though higher production sites are expected to have higher equipment counts. In the likely case that low-production sites tend to have lower equipment counts, then this method of estimating site-level PTE over-assigns pneumatic pumps and controllers to these sites, which means EPA projects that less sites are below 3 tpy than would be expected. Second, these methods do not account for regional differences in emission factors or natural gas composition. Finally, and most critically, these approaches do not account for anomalous emission rates that can occur due to malfunctions. For example, a high production natural gas site with low equipment counts and little condensate production may have a low PTE based on these calculations, but if the separator dump valve is left open, then the site's emissions may be several orders of magnitude higher.

Using the Rutherford model, commenter (0844-EDF *et al.*) separately evaluated the sites and emissions from sites that EPA would classify as below 3 tpy. The commenter estimates that of all the sites EPA's analysis would place below 3 tpy, 22 percent actually have emissions above

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<sup>90</sup> Attachment G (Lyon PTE Analysis).

<sup>91</sup> *Id.*

that threshold. Those 22 percent of sites account for 90 percent of total emissions from all sites that would qualify for the exemption under EPA's analysis. In other words, 90 percent of the unabated emissions that EPA estimates would result from the 3 tpy exemption originate from sites that should not, in fact, qualify for that exemption based on their actual emissions. Further, their analysis indicates that emissions from sites EPA would deem below 3 tpy PTE are underestimated by a factor of four.<sup>92</sup>

Response I-7-47: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>93</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) states EPA's November 2021 Proposal to require a one-time inspection at smaller sites is an inadequate approach for dealing with fugitive emissions from oil and gas sources, which are known to be intermittent, varying in size, and difficult to predict. For instance, operators may choose to conduct one-time monitoring during favorable conditions that do not accurately reflect the true extent of emissions from the site in question. And even if a one-time survey is conducted properly, it only represents a snapshot in time, and an equipment failure (particularly for sites with failure-prone equipment like tanks and flares) could cause the same site to begin experiencing large emissions any time after the survey. The commenter argues under the proposed approach, super-emitters at these sites could go permanently undetected. Many of the smaller sites that would be allowed to conduct a one-time survey are older and declining in production and are therefore more likely to be poorly maintained. Most of them have also never been subject to federal air-pollution regulation and have likely never upgraded any of their equipment. These older, declining sites are less valuable to operators who have little financial incentive to maintain them properly, resulting in components that may be rusted and in poor condition. All of these factors make sites below 3 tpy highly prone to leaks and equipment failures, and a one-time inspection does not resolve that problem.

The commenter (0844-EDF *et al.*) continues, results from recent surveys conducted in the Permian Basin confirm that emissions from low production sites are recurrent and would not be mitigated by a one-time inspection and repair standard.<sup>94</sup> From November 12-21, 2021, the commenter contracted Leak Survey Inc. (LSI) to survey emissions across the Permian Basin using helicopter-based OGI. With an infrared camera mounted to an R44 helicopter with a gimbal for image stabilization, LSI visited 519 different upstream production sites. LSI then returned to 154 of these sites to collect repeat observations within a week's time. At each site, LSI noted any source of detectable methane emissions and recorded video, which are publicly available along with a complete methodology on Permianmap.org. Over 80 percent of

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<sup>92</sup> Id.

<sup>93</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>94</sup> Attachment B (PermianMAP November 2021 Flyover Results); see also EDF, Methodology for EDF's Permian Methane Analysis Project (PermianMAP) (Nov. 17, 2021), [https://www.edf.org/sites/default/files/documents/PermianMapMethodology\\_1.pdf](https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf).



observations were linked to production data from Enverus Prism by totaling the amounts of oil and gas produced within a 175m radius buffer from the latitude and longitude reported by LSI. Roughly 60 percent of observations were from low-producing sites generating less than 15 BOED.

The commenter (0844-EDF *et al.*) finds these low-producing sites had a higher rate of flare malfunctions (31.3 percent) when compared to higher production sites (9.4 percent). Additionally, the malfunctioning flares found at low-producing sites were almost all (90.5 percent) completely unlit and venting methane.<sup>95</sup> Even if only active for a short period of time, unlit flares release large amounts of methane into the atmosphere. For example, a flare with 98 percent combustion efficiency would have nearly fifty times higher emissions than normal when unlit. Possible causes of this high rate of malfunction include the intermittency of flares at these sites, due to low production levels, as well as likely less-frequent site visits by operators. The fact that low-producing sites more often exhibit one of the most consequential equipment malfunctions stresses the importance of surveying those sites frequently.

The commenter (0844-EDF *et al.*) states when comparing repeat observations from low-producing sites within a week, 56.3 percent of sites (54/96) had detectable emissions at some point. This includes emissions from all equipment types, such as flares, tanks, separators, and compressors. About one-third of sites had emissions during one site visit and not the other, while about one-quarter had detectable emissions during both visits. Of the sites with emissions observed during both visits, more than half of the sites had different pieces of equipment emitting on each day.

Although the analysis is segregated based on production, commenter (0844-EDF *et al.*) expects similar emission trends between the low-producing sites surveyed and Permian sites classified as less than 3 tpy PTE, given the low production and relatively low equipment counts of the surveyed sites. Based on EPA's PTE methodology in RIA Appendix A, the commenter estimates these sites would have a maximum emission rate of ~10 tpy for tank and fugitive emissions. One-time monitoring is inadequate because these sites often have highly intermittent emissions and emissions that emanate from variable pieces of equipment. At the low-producing sites where LSI collected repeat observations, a site visit on only one day would fail to mitigate emissions from 52.8 percent of sites that had multiple emission sources over two days.<sup>96</sup>

Response I-7-48: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>97</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

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<sup>95</sup> See Attachment I (Warren Permian Slides 2021) ("Insights from Repeated Helicopter OGI on Methane Emissions and Flaring Performance across Industry Segments in the Permian Basin.").

<sup>96</sup> On average, the sites that would still have emissions after one day of survey and repairs include one half of the sites that had emissions on one survey day and not the other, along with the sites that had emissions on both days but from different sources each day. These sites total 28.5 out of the 54 sites seen to have emissions across both days.

<sup>97</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0844-EDF *et al.*) states several recent studies demonstrate that smaller wells emit a significant percentage of their gas production—some venting all of their reported produced gas to the atmosphere, or even losing more gas through leaks than they produce for sale.<sup>98</sup> A recent study involving site-level measurements of over seventy well pads in the Permian Basin found that methane emissions are higher than in most other measured basins. This study also found no relationship between production and emissions, and that marginal wells had similar emissions to non-marginal wells.<sup>99</sup> Other recent observations in the Permian Basin have confirmed that marginal sites and even wellhead-only sites can be sources of the largest methane plumes.<sup>100</sup>

The commenter (0844-EDF *et al.*) adds another 2018 study investigated methane emissions characteristics to develop a new national methane emission estimate for the natural gas production sector. The study used site-level methane emissions data from over 1,000 natural gas production sites in eight basins, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg basins.<sup>101</sup> It examined natural gas production sites and categorized them as low (sites producing 1,000 Mcfd). The study found that low natural gas production sites “emit a larger fraction of their CH<sub>4</sub> production” than the intermediate and high production sites.

The commenter (0844-EDF *et al.*) states a 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells in the Appalachian Basin of southeastern Ohio, all producing <1 BOE/d, found similar results.<sup>102</sup> The study found that marginal wells are a disproportionate source of methane and VOC emissions relative to production. It estimated that oil and gas wells in this lowest production category emit approximately 11 percent of total annual methane from oil and gas production reported in EPA’s GHGI, even though they produce only about 0.2 percent of oil and 0.4 percent of gas in the U.S. per year.

The commenter (0844-EDF *et al.*) states despite this wealth of data examining emissions from marginal sites, some industry stakeholders have claimed that EPA does not have enough information to regulate marginal sites and should wait for a pending study conducted by GSI Services with funding from the Department of Energy.<sup>103</sup> Yet this study looks only at emissions from sites that operators volunteered for the study and primarily utilizes component-level measurements that have been demonstrated to underestimate site-level emissions. Even so, drafts of the study show general agreement with skewed emission distributions but find lower average

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<sup>98</sup> Deighton et al., Measurements show that marginal wells are a disproportionate source of methane relative to production, 70 J. of Air & Waste Mgmt. 1030 (2020), <https://www.tandfonline.com/doi/full/10.1080/10962247.2020.1808115> ; see also EDF Marginal Well Factsheet (2021), [https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021\\_0.pdf](https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf) .

<sup>99</sup> Robertson et al., New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5-9 Times Higher Than U.S. EPA Estimates, 54 Env. Sci. Tech. 13926 (2020), <https://pubs.acs.org/doi/pdf/10.1021/acs.est.0c02927>.

<sup>100</sup> Attachment B (PermianMAP November 2021 Flyover Results).

<sup>101</sup> Omara et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, 52 Env. Sci. Tech. 12915 (2018), <https://pubs.acs.org/doi/10.1021/acs.est.8b03535>.

<sup>102</sup> Deighton et al., Measurements show that marginal wells are a disproportionate source of methane relative to production (2020).

<sup>103</sup> See, e.g., IPAA, SER Comments (Aug. 12, 2021), [https://www.ipaa.org/wp-content/uploads/2021/08/SER103Comments-GO-WV.IPAA\\_.TIPRO-color.pdf](https://www.ipaa.org/wp-content/uploads/2021/08/SER103Comments-GO-WV.IPAA_.TIPRO-color.pdf).

emission rates than other literature. Nothing contained in the draft study significantly changes what is already known about emissions from marginal sites.

The commenter (0844-EDF *et al.*) adds that the most comprehensive study of marginal well site (<15 BOED) emissions to date finds that these sites have production-normalized methane loss rates six to twelve times higher than other sites and represent roughly half (37-75 percent) of all U.S. production site methane emissions.<sup>104</sup> While 80 percent of production sites nationwide contain these marginal wells, they only produce 6 percent of the nation's oil and gas output. Nationally, about 60 percent of marginal sites are ultra low-production sites, producing less than 2 BOED. These wells generate just a trickle of usable product despite disproportionately harming human health and the environment.

The commenter (0844-EDF *et al.*) states the Omara *et al.* study uses available production data from Enverus to assess marginal sites' regional distribution, production characteristics, and operator profiles. Using this data in combination with data on marginal well site emissions previously collected from a diversity of regions across the U.S., the study generates a new national estimate of the total methane emissions from marginal well sites and assesses the significance of these emissions in comparison to emissions from all U.S. production sites. Omara *et al.*'s assessment carries significant policy implications for effective mitigation of U.S. oil and gas methane emissions. It finds that marginal well sites are abundant and that their methane losses occur at high rates exceeding 10 percent of site-level methane production.<sup>105</sup> Field-based observations point to avoidable maintenance-related issues as a key driver of emissions at marginal well sites, particularly at older, lower-producing sites that tend to suffer from prolonged lack of attention from their owners or operators<sup>106</sup>—the precise problem that would be rectified by regular monitoring requirements. Even as their production declines over time, marginal sites' emissions continue from both routine and nonroutine, but avoidable, sources. Marginal sites also display the fat-tailed emission distribution commonly observed in the oil and gas sector.<sup>107</sup> Identifying high-emitting sites and uncovering the root causes of excessive emissions is key to mitigation.

The commenter (0844-EDF *et al.*) argues recognizing the disproportionately large role that low-producing sites play in contributing to total emissions in the U.S. is critical to developing appropriate regulations and achieving targeted reductions.<sup>108</sup> Exemptions for marginal sites risk leaving half of production site emissions unabated without adequate justification. Given that marginal sites generate less than 6 percent of domestic oil and gas production, there are no legitimate concerns that requiring their owners to regularly monitor them and repair equipment leaks would significantly harm domestic energy production. The commenter argues these studies underscore the critical importance of regular LDAR at the smallest of sites—many of which

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<sup>104</sup> Omara et al., Methane emissions from U.S. marginal oil and gas wells, \_\_ Nat. Comms. \_\_ (2021) (accepted for publication); Attachment A (Omara AGU Slides 2021); March 12 EDF Meeting Slides Attachment - Marginal Wells, available here: <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0107>.

<sup>105</sup> Id.

<sup>106</sup> Deighton et al., Measurements show that marginal wells are a disproportionate source of methane relative to production. 70 J. Air & Waste Mgmt. 1030-1042 (2020); Omara et al., Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region, 50 Env. Sci. Tech. 2099—2107 (2016).

<sup>107</sup> Attachment A (Omara AGU Slides 2021).

<sup>108</sup> Id.

would be exempt under EPA’s proposed 3 tpy threshold. These wells—which number in the hundreds of thousands—produce very little usable product, yet they are large and disproportionate polluters. EPA must ensure emissions from these wells are minimized by requiring regular monitoring and repairs.

Response I-7-49: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>109</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF et al.) states EPA partially justifies the 3 tpy exemption on a finding that “given the diversity of ownership, while their cost assumption that distributes the costs of recordkeeping evenly across 22 sites within a company-defined area is a reasonable estimate for the population as a whole, it may underestimate the costs and therefore overestimate the cost-effectiveness for owners with fewer than 22 well sites (and conversely, underestimate cost-effectiveness for owners with more than 22 well sites).”<sup>110</sup> Again, this consideration is incorrectly applied to smaller sites: any different treatment on the basis of production (or potential emissions) will likely disproportionately benefit larger operators who own many sites. The vast majority of marginal sites are owned by companies operating 50 or more sites—and this is without considering those companies’ additional ownership of non-marginal sites.<sup>111</sup>

The commenter (0844-EDF *et al.*) finds throughout the November 2021 Proposal, EPA seems to believe that smaller sites are owned by smaller companies that operate fewer wells. EPA provides no justification for this assumption, and the commenter’s analyses of Enverus Prism data shows that it is incorrect. Ninety-two percent of marginal well sites are actually owned by larger companies, defined as those that operate 25 or more sites.<sup>112</sup> The commenter’s analysis also shows that more than three-quarters of marginal wells are owned by companies that operate more than one hundred well sites and generate hundreds of millions in gross revenue each year.<sup>113</sup>

Response I-7-50: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>114</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

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<sup>109</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>110</sup> 86 Fed Reg 63190.

<sup>111</sup> Attachment A (Omara AGU Slides 2021).

<sup>112</sup> Attachment J (Wolfe & Lackner Operatorship Analysis).

<sup>113</sup> As noted above, although marginal production does not directly correlate to PTE, many marginal sites will fall below 3 tpy using EPA’s proposed calculation.

<sup>114</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0844-EDF *et al.*) states a tiering system that is based on self-determined PTE calculated via a complex mathematical formula is prone to human error and gamesmanship. It will also be more difficult to enforce because determining the applicable regulatory standard for a site requires a regulator to conduct the same complex mathematical calculation. A site's PTE is likely to change over time, as equipment is added and removed and as production levels vary. EPA has proposed that operators would have to recalculate PTE every time equipment is added or removed from the site, creating further potential for error and confusion.<sup>115</sup> If EPA retains a tiered approach, categorically excluding sites with failure-prone equipment from tiers subject to less frequent monitoring is a solution that would ease some enforcement concerns.

The commenter (0844-EDF *et al.*) continues, in the article *Next Generation Compliance: Preventing Widespread Violations that Threaten Climate Goals*, Cynthia Giles highlights methane regulations for oil and gas production as “the classic situation in which compliance is likely to be bad.”<sup>116</sup> The oil and gas sector has many characteristics that make it prone to poor compliance, including: “millions of widely dispersed sources; emissions that are hard to observe or measure; industries that know government’s chances of figuring out they are in violation are low; and many states that are unwilling to hold operators accountable.”<sup>117</sup> The article also points out that the “widespread and faulty assumptions that most companies comply, and that enforcement can take care of the rest, are obviously incorrect here,” arguing that more stringent standards will lead to even greater noncompliance as operators—many of whom have never been subject to federal methane regulation—are faced with new costs.<sup>118</sup> Giles’ topline recommendations for federal oil and gas regulations are to 1) aim for clarity and simplicity, 2) minimize exemptions, and 3) require frequent monitoring.<sup>119</sup> The commenter includes Giles’ recommendations in detail.<sup>120</sup>

The commenter (0844-EDF *et al.*) argues Giles’s concerns are directly applicable to the November 2021 Proposal’s exemption from regular monitoring for sites below 3 tpy, and to the co-proposed middle tier. In the November 2021 Proposal, EPA proposed to draw lines between categories of sites for differential treatment and plans to let operators themselves calculate where their sites fall. EPA has thus built in pathways to noncompliance and created incentives for operators to find ways to qualify for less frequent monitoring. And once an operator has decided its site is below 3 tpy and conducted a one-time inspection, that site will no longer be monitored or subject to recordkeeping and reporting standardse.

The commenter (0844-EDF *et al.*) argues enforcement is likewise complicated and made less effective by the tiering structure. Inspectors will be unable to simply visit a site and determine its compliance obligations. Rather, they will have to conduct a PTE calculation, which they will

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<sup>115</sup> 86 Fed. Reg. 63170.

<sup>116</sup> Cynthia Giles, *Next Generation Compliance, Part 4: Preventing Widespread Violations that Threaten Climate Goals*, Harvard EELP, at 43 (April 2021), <http://eelp.law.harvard.edu/wp-content/uploads/Cynthia-Giles-Part-4-FINAL.pdf> [hereinafter *Next Generation Compliance*].

<sup>117</sup> Giles, *Next Generation Compliance* at 45; see also EPA, *New Owner Clean Air Act Audit Program for Upstream Oil and Natural Gas Exploration and Production Facilities, Questions and Answers*, at 1 (March 29, 2018), <https://www.epa.gov/sites/production/files/2018-06/documents/qaoilandnaturalgasnewownerauditprogram>.

<sup>118</sup> Giles, *Next Generation Compliance* at 47.

<sup>119</sup> *Id.* at 48-49.

<sup>120</sup> *Id.* at 48-49.

then compare to the operator's own calculation, and will have to resolve any resulting discrepancies before determining the source's compliance obligations. Nor can inspectors determine a site's compliance obligations through by monitoring, since PTE is not reflective of the site's actual emissions. These concerns are exacerbated by the resource limitations that EPA and states will face when enforcing these rules at hundreds of thousands of sources nationwide. For these reasons alone, EPA should eliminate the PTE-based tiered monitoring system and require quarterly monitoring at all sites. At a minimum, EPA should include equipment-based categorical exclusions so it is visibly apparent upon a site inspection what frequency of monitoring is required.

Response I-7-51: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, which included an equipment-based approach for determining the fugitive emissions monitoring requirements.<sup>121</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) states a problem with the 3 tpy threshold is that by exempting these frequently older sites from regular inspections and federal requirements, operators will have no reason or incentive to take care of them and ensure they are properly shut down. In fact, the exemption creates the opposite incentive: because an operator would not have to spend any money or take any steps to comply with the regulations, they would be incentivized to leave the site as-is rather than properly shut it down. The commenter believes EPA should structure regulatory requirements to ensure proper maintenance and closure as well sites reach the end of their productive and economically viable lives. By failing to require regular inspections at smaller wells, EPA is enabling poor maintenance and disincentivizing proper plugging and closure.

The commenter (0844-EDF *et al.*) continues, as regulations become more stringent and leading operators endeavor to reduce their emissions, operators increasingly offload underperforming assets to smaller companies that lack shareholder and other external pressure to reduce emissions.<sup>122</sup> A lack of stringent regulatory requirements for these under-performing assets makes them more attractive to prospective buyers who lack both internal emission reduction goals and would not face regulatory pressure to cut emissions.<sup>123</sup> And to larger companies seeking to reduce their overall emissions, these are "assets with disproportionately high

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<sup>121</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>122</sup> Hiroko Tabuchi, Here Are America's Top Methane Emitters. Some Will Surprise You., New York Times (Oct. 2021) <https://www.nytimes.com/2021/06/02/climate/biggest-methane-emitters.html> ("As the world's oil and gas giants face increasing pressure to reduce their fossil fuel emissions, small, privately held drilling companies are becoming the country's biggest emitters of greenhouse gases, often by buying up the industry's high-polluting assets.").

<sup>123</sup> See, e.g., Zachary Mider and Rachel Adams-Heard, Diversified Energy Said Emissions Fell. Now It Says They Didn't: U.S. gas producer told investors one thing, regulators another, Bloomberg Green (Oct. 20, 2021), <https://www.bloomberg.com/news/articles/2021-10-20/gas-producer-diversified-energy-said-emissions-fell-now-it123says-they-didn-t>.

emissions primed for disinvestment.”<sup>124</sup> This problem is borne out in emissions data for companies, which shows that “five of the industry’s top ten emitters of methane . . . are little-known oil and gas producers, some backed by obscure investment firms, whose environmental footprints are wildly large relative to their production.”<sup>125</sup>

The commenter (0844-EDF *et al.*) states a lack of federal requirements to detect and fix leaks may make these assets more attractive to buyers and allow the high-polluting practice of extending the lives of aging, underperforming sites, even while they often lack the funds to pay for plugging.<sup>126</sup> Exempting smaller sites from regular inspections could thus encourage companies to buy up these underperforming and high-polluting sites and keep them operating longer before potentially going bankrupt, leaving taxpayers holding the bag.<sup>127</sup> Among many other reasons described herein, EPA should subject these sites to similar requirements as other well sites to avoid inadvertently incentivizing and subsidizing irresponsible business models.<sup>128</sup>

Response I-7-52: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>129</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) reiterates utilization of the Rutherford model indicated that 22 percent of sites that could be placed in the less than 3 tpy PTE tier are actually likely to emit more than 3 tpy.<sup>130</sup> This analysis required matching the commenter’s 2019 wellsite dataset to 2019 GHGRP facilities and wells. The commenters were then able to determine which facilities had average emissions per site below 3 tpy. Of the approximately 530,000 wells in EF\_W\_ONSHORE\_WELLS\_2019 from the 2019 GHGRP Subpart W dataset<sup>131</sup> they were able to match ~460,000 wells with production in 2019 (330,000 sites) from Enverus Prism. Of the sites matched to GHGRP facilities, more than 50 percent of sites were determined to be at facilities with average site level emissions below 3 tpy and 25 percent of sites between 3 and 8

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<sup>124</sup> Andrew Baxter and Gabriel Malek, Oil and gas companies, investors, and policymakers all have important roles to play to solve the problem of transferred emissions, Investor Engagement (Nov. 2021), <https://business.edf.org/insights/why-we-need-leadership-to-close-the-transferred-emissions-loophole/>.

<sup>125</sup> Hiroko Tabuchi, Here Are America’s Top Methane Emitters. Some Will Surprise You., New York Times (Oct. 2021) <https://www.nytimes.com/2021/06/02/climate/biggest-methane-emitters.html> (citing CATF, Benchmarking Methane and Other GHG Emissions of Oil & Natural Gas Production in the United States (June 1, 2021), <https://www.catf.us/resource/benchmarking-methane-emissions/>).

<sup>126</sup> See, e.g., Zachary Mider and Rachel Adams-Heard, Diversified Energy Said Emissions Fell. Now It Says They Didn’t: U.S. gas producer told investors one thing, regulators another, Bloomberg Green (Oct. 20, 2021), <https://www.bloomberg.com/news/articles/2021-10-20/gas-producer-diversified-energy-said-emissions-fell-now-it-says-they-didn-t>.

<sup>127</sup> Haynes Boone, Oil Patch Bankruptcy Monitor (June 30, 2021), [https://www.haynesboone.com/-/media/project/haynesboone/haynesboone/pdfs/energy\\_bankruptcy\\_reports/oil\\_patch\\_bankruptcy\\_monitor.pdf?rev=61c2606a5be547598c8d716d1a795c39&hash=97ECA4B149560404B19497FA37CB2B50](https://www.haynesboone.com/-/media/project/haynesboone/haynesboone/pdfs/energy_bankruptcy_reports/oil_patch_bankruptcy_monitor.pdf?rev=61c2606a5be547598c8d716d1a795c39&hash=97ECA4B149560404B19497FA37CB2B50).

<sup>128</sup> See Part IV.J (Abandoned Wells) (discussing end-of-life well issues).

<sup>129</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>130</sup> Attachment K (Rutherford PTE Slides).

<sup>131</sup> EPA 2019 Greenhouse Gas Reporting Program Subpart W (2021). Retrieved from Envirofacts: <https://www.epa.gov/enviro/greenhouse-gas-customized-search>.

tpy. Average site level emissions were calculated using reported 2019 emission data and the number of matched sites at each facility. While the sites below 3 tpy emitted about 11 percent of reported 2019 facility emissions, they produced almost 30 percent of matched 2019 production. Comparatively, sites between 3-8 tpy emit almost 25 percent of reported emissions but produce the lowest fraction of production, 24 percent. While the commenter would need to run the Rutherford Model for these sites specifically, it is reasonable to assume that with a more accurate prediction method, the commenter would also find that sites originally placed in the 3-8 tpy tier have higher emissions in reality.

Response I-7-53: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>132</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) states EPA should require quarterly or more frequent OGI at all sites regardless of the site-level emission estimate, particularly if EPA retains its well-head only exemption. If EPA retains the tiered approach, it should exclude sites with failure-prone equipment from tiers subject to less frequent monitoring and should revise the PTE calculation to account for the well-documented existence of super-emitters. Covering smaller, leak-prone wells with frequent inspections is critical as the commenter's analysis here shows that EPA's currently proposed one time only inspections at these well sites could reduce the overall effectiveness of its LDAR program by as much as half.

Response I-7-54: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>133</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) argues the November 2021 Proposal's PTE calculation is less likely to accurately capture potential emissions when considering its application to smaller sites that may calculate less than 3 tpy, allowing those sites to avoid regular monitoring and repair. These sites, many of which are declining marginal or stripper wells, are even less likely than other sites to be operating correctly in the way the proposed PTE calculation assumes.<sup>134</sup> Most of these declining sites have never been subject to federal air pollution regulations, will have older and more-leak prone equipment and components, and are likely lowest on operators' priority lists for regular inspections and equipment upgrades.<sup>135</sup> All of these factors suggest that

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<sup>132</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>133</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>134</sup> See Attachment B (PermianMAP November 2021 Flyover Results).

<sup>135</sup> Wendt *et al.*, Methane Gas Emissions - is Older Infrastructure Leakier?, AGU (2015) <https://ui.adsabs.harvard.edu/abs/2015AGUFM.A43F0346W/abstract>.



many sites calculating less than 3 tpy are among the most likely to emit above the level otherwise determined by EPA's calculation under the November 2021 Proposal.

Response I-7-55: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>136</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0326-Driss A. Lonqueux (Private Citizen), 0357-National Parks Conservation Association (NPCA), 0398- Representative Barragan *et al.*, 0437-NYOSC, 0560-LGIM America, 0605-Muscogee (Creek) Nation, 0715-Dayenu Circle of Jewish Silicon Valley (DCJSV), 0744-New York State Department of Environmental Conservation (NYSDEC); 0753-IGSD/CHRE, 0803-OOGA, 0822-Texas Alliance of Energy Producers (TAEP), 0833-Ute EPD, 0943-Sault EPD, 1267-CA AG *et al.*, 1270-League of Women Voters of the United States (LWVUS), 1387-350 Bay Area Action, 1388-Private Citizen, 1423-Representative Beyer *et al.*, 1434-Senator Heinrich *et al.*) encourage the EPA to issue the strongest regulations possible in oil and gas monitoring, regardless of source-size, to ensure that leaks and plumes are included. It is commonly understood that oil and gas sites currently emit more methane (often many times more) than is generally estimated, due to the existence of unaccounted-for methane plumes and leaks.

The commenter (0560-LGIM America) adds research has shown that these wells can often be a significant source of methane emissions and the lack of ongoing monitoring may allow them to continue the outsized rate of pollution. Ownership data has also shown that such wells are often owned by large companies, who likely have the financial wherewithal to perform more robust maintenance.<sup>137</sup>

Response I-7-56: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>138</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0326-Private Citizen) states the November 2021 Proposal shows unprecedented intention to expand requirements to existing sources. Identifying and repairing leaks is essential and quarterly inspections are a good start. The use of a production level threshold to determine the exemption of well sites is flawed because low-production sites account for disproportionately high levels of methane emission. While the November 2021 Proposal seeks to focus monitoring efforts on sites with larger likelihood of leakage, low-production wells are generally older and therefore more prone to fugitive emissions. They must be submitted to the same rigor of monitoring. The monitoring and reporting of wells cannot be

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<sup>136</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>137</sup> [https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021\\_0.pdf](https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf).

<sup>138</sup> 87 FR 74724-74736 (December 6, 2022).

conditioned on output. With over 75 percent of marginal well sites owned by large companies with over 100 active wells, there is no reason for these companies, which already monitor their high-production wells—not to bear the cost of monitoring and reporting performance standards on low-production wells. The commenter recommends that the EPA removes the inspection exemption on low-production wells to ensure that (1) well-resourced companies are not given a free pass to pollute and (2) the improvements due to increased monitoring efforts are not offset by exemption loopholes.

Response I-7-57: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>139</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (1270-LWVUS) states small producers are less likely to take these actions voluntarily because they are often using old equipment on wells that have long since passed peak production, meaning that their ratio of leaked gas to marketed gas is much higher than that of major producers. The November 2021 Proposal appears to emphasize self-reporting. The commenter believes that this needs to be augmented by oversight and independent measurements of leakage at the well sites.

Response I-7-58: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>140</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0803-OOGA) objects to EPA’s November 2021 Proposal to remove the exemption (from the requirement to monitor fugitive emissions) for low production wells from Subpart OOOOa. 286 FR 63170 and urges EPA to retain the exemption for low-production wells. A significant portion of the more than 61,000 wells in Ohio meet the definition of a low production well (*i.e.*, produce at or below 15 barrels of oil equivalent per day (BOED) and, in fact, produce on average far less than 15 BOED. Notwithstanding the Association’s objection to removing the exemption for low production wells, the November 2021 Proposal’s site-level baseline methane estimate methodology to determine whether a well site is subject to the fugitive emissions monitoring requirement is flawed for several reasons.

Commenter (0431-NuEnergy Operating, Inc. (NuEnergy)) states that the lower limit for exempt wells is too low and could easily be tripled with negligible effect on the environment.

Response I-7-59: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii

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<sup>139</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>140</sup> 87 FR 74724-74736 (December 6, 2022).

of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>141</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (1423-Representative Beyer *et al.*; 1434-Senator Heinrich *et al.*) argue EPA should finalize a comprehensive rule that includes pollution reduction requirements for smaller wells. There are thousands of these wells scattered across the country and while they produce very little usable product, they can be a significant and disproportionate source of methane emissions. Under the November 2021 Proposal, operators that calculate lower potential emissions could escape regular leak monitoring. This gap needs to be addressed before the EPA rules are finalized to ensure that smaller wells are also regularly monitored.

The commenter (1423-Representative Beyer *et al.*) adds that such wells comprise a majority of the nation's fleet of oil and gas wells, produce a small fraction of the nation's petroleum, and are responsible for an outsize share of methane emissions from the industry.<sup>142</sup> In order to protect public health, particularly in frontline communities, EPA must ensure these wells receive frequent inspections to find and fix pollution leaks. Furthermore, the fact that the vast majority of these wells are owned by large operators and the availability of technology for cost-effective leak monitoring and detection means any carve-outs or exemptions are simply unnecessary. Reducing methane emissions can create good, high-quality jobs. The methane mitigation service sector in the U.S. has nearly doubled in size since 2017 and would have further opportunity to grow.<sup>143</sup>

Response I-7-60: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>144</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0605-Muscogee (Creek) Nation, 0833-Ute EPD, 0943-Sault EPD) support the November 2021 Proposal's increased frequency of fugitive emissions monitoring for new and existing sources. The commenters believe that the shortest duration of time between monitoring should be used in the final rule. Because many large emission events occur because of leaking equipment, longer monitoring periods would allow leaks to continue to emit unchecked for longer periods of time.

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<sup>141</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>142</sup> Deighton, Jacob A., et al. "Measurements show that marginal wells are a disproportionate source of methane relative to production." *Journal of the Air & Waste Management Association*, vol. 70, no. 10, Oct. 2020, pp. 1030-1042, <https://pubmed.ncbi.nlm.nih.gov/32776822/>; Omara, Mark, et al. "Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin." *Environmental Science & Technology*, vol. 50, no. 4, Feb. 2016, pp. 2099-<https://pubs.acs.org/doi/10.1021/acs.est.5b05503>.

<sup>143</sup> Lowe, Marcy, et al. "Find, Measure, Mix: Jobs in the U.S. Methane Emissions Mitigation Industry." Environmental Defense Fund Report, Prepared by Datu Research, June 2021.

<https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf>.

<sup>144</sup> 87 FR 74724-74736 (December 6, 2022).

The commenters (0605-Muscogee (Creek) Nation, 0833-UTE EPD, 0943-Sault EPD) support the use of advanced technologies, but for them to be used as a complement to the required monitoring until the technologies are more proven. Once the advanced technologies are proven, the owner/operator can submit them for approval as an equivalent alternative method. The commenters feel this is important to protect fenceline communities from the HAP associated with oil and natural gas emissions.

The commenter (0833-UTE EPD) believes that the use of OGI should be emphasized over EPA Method 21 for monitoring and that Method 21 should not be used for follow-up surveys after emissions were detected. The commenter (0833-UTE EPD) believes OGI is more efficient and effective at identifying leaks and fugitive emissions.

The commenters (0605-Muscogee (Creek) Nation, 0833-UTE EPD, 0943-Sault EPD) believe well sites with estimated emissions of less than 3 tpy should be required to conduct quarterly or at least regular monitoring for leaks, particularly where leak-prone equipment is present on the site. Again, leaks and malfunctions are the largest source of emissions. Just because a well site has lower estimated emissions, does not mean that the equipment will not malfunction or fail resulting in significant emissions. These leaks and malfunctions must be identified and addressed as soon as possible to avoid emission of VOC, methane, and HAP. A single inspection after the rule is finalized will not address this problem.

Response I-7-61: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>145</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (1267-CA AG *et al.*) states EPA's November 2021 Proposal of a one-time survey for sites with PTE of 3 tpy or less to "ensure that they are operating in a well-controlled manner and not experiencing leaks or malfunctions that would cause their emissions to exceed 3 tpy,"<sup>146</sup> does not address the problem of future leaks or malfunctions. Malfunctions are known to account for a large amount of methane emissions. The commenter (1267-CA AG *et al.*) urges EPA at a minimum to require a resurvey or monitoring on at least an annual basis to account for such situations.

The commenter (1267-CA AG *et al.*) recommends, based on the experience of some leading states, that EPA consider requiring regular fugitive emissions monitoring and repair for all well sites regardless of their PTE or production level. Large leaks can happen at any time, even at well sites with low PTE, and regular monitoring is necessary to detect and mitigate those fugitive emissions. EPA's exemption of well sites with a PTE of less than 3 tpy also leaves a significant source of methane emissions on the table. According to EPA's 2021 GHGI, fugitive methane emissions for 2019 in the oil and natural gas source category were 96,000 metric tons methane for petroleum systems and 351,500 metric tons for natural gas systems, for a total of 447,500

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<sup>145</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>146</sup> *Id.* at 63,190.

metric tons.<sup>147</sup> And scientific evidence shows that EPA inventories dramatically underestimate the amount of methane emitted by the oil and natural gas sector. A synthesis of site-level emissions studies in 2018 found that the U.S. oil and natural gas sector methane emissions are approximately 60 percent higher than EPA estimates.<sup>148</sup> By EPA's estimate, approximately 86 percent of fugitive emissions can be attributed to wells with site-wide baseline emissions of 3 tpy or greater.<sup>149</sup> Thus, EPA's proposed exemption for well sites with PTE of less than 3 tpy would leave approximately 14 percent of fugitive emissions—as much as 100,000 metric tons of methane by some estimates—unregulated.

Response I-7-62: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>150</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0744-NYSDEC) adds, if adopted, New York's Part 203 rulemaking will cover lower producing wells, based on the finding that exempting such wells would decrease emissions reductions in this subsector around 95 percent. The commenter strongly urges EPA to consider the contribution of methane from these wells, including their potential to be super-emitters, to determine if future action is warranted. 1, the commenter recommended that EPA work with small-business sources to identify areas where they may gain experience and other resources in meeting the requirements to ensure critical emission reductions. EPA has not yet addressed this, and the commenter suggests that this be considered for future work.

Response I-7-63: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>151</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0795-American Lung Association (ALN) *et al.*) provides studies and data that conclude fugitive emissions are underestimated and smaller wells are a major contributor.

The commenter (0795-ALN *et al.*) states considerable amounts of methane leak from oil and gas wells, driving up atmospheric methane levels and exacerbating climate change. Quantifying that leakage has proven difficult, with academic studies estimating average leaks from active gas

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<sup>147</sup> 86 Fed. Reg. at 63,186.

<sup>148</sup> See Alvarez *et al.*, Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 Sci. 186-88 (2018); see also Omara *et al.*, Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, 52 Env. Sci. Tech. 12915 (2018), <https://pubs.acs.org/doi/10.1021/acs.est.8b03535>; Cusworth *et al.*, Intermittency of Large.

<sup>149</sup> 86 Fed. Reg. at 63,190.

<sup>150</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>151</sup> 87 FR 74724-74736 (December 6, 2022).

wellsites (encompassing production, gathering, and processing) at rates ranging from 1.9 percent<sup>152</sup> to nearly 10 percent.<sup>153</sup> Regardless of the uncertainty over the precise amount, the problem of methane leakage from oil and gas wells is significant, and EPA is right in calling for meaningful steps to identify those leaks and repair them.

Commenter (0795-ALN *et al.*) argues not all wells contribute equally to methane leakage. Marginal wells near the end of their lifespans—so-called stripper wells—appear to represent a disproportionately large source of methane emissions relative to their production, according to a study published in 2020.<sup>154</sup> The study found that stripper wells typically are not profitable to operate but because the cost of decommissioning them can be greater than the cost of keeping them running they are kept online or at the ready, sometimes leaking more gas than what is intentionally extracted, captured, and used. An estimated 700,000 of these low-producing, marginal wells exist in the United States. The commenter continues, while many stripper wells have low emissions, a few emit at much higher levels. On the face of it, this would seem to make high-emitting stripper wells an ideal target for regulation. However, researchers have found it difficult to predict which wells are going to be “super-emitters.” Furthermore, where emissions are intermittent, accurate measurement would require continuous, site-specific monitoring, which is not a realistic prospect given the number of possible leak sites and the time and cost required to deploy enough inspectors and equipment. Thus, a broadly applicable regimen of monitoring and repair is necessary, with small wells and large ones subject to regular leak inspection and requirements for repair. Any proposal that would exempt wells whose operators calculate low levels of emissions would be misguided.

Commenter (0753-IGSD/CHRE) cites a study that found including leaks in methane emission estimates would result in emissions estimates 48–76 percent greater than the EPA’s current estimates.<sup>155</sup> In places where oil and gas production has decreased, methane leaks may still

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<sup>152</sup> Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, et al. 2018. “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain.” *Science* 361 (6398): 186–88. <https://doi.org/10.1126/science.aar7204>.

<sup>153</sup> Howarth R.W. October 8, 2015. “Methane emissions and climatic warming risk from hydraulic fracturing and shale gas development: implications for policy” in *Energy Emission and Control Technologies*. [http://www.eeb.cornell.edu/howarth/publications/f\\_EECT-61539\\_perspectives-on-air-emissions-of-methane-and-climatic-warmin\\_100815\\_27470.pdf](http://www.eeb.cornell.edu/howarth/publications/f_EECT-61539_perspectives-on-air-emissions-of-methane-and-climatic-warmin_100815_27470.pdf).

<sup>154</sup> Jacob A. Deighton et al. 2020. “Measurements Show That Marginal Wells Are a Disproportionate Source of Methane Relative to Production,” *Journal of the Air & Waste Management Association* 70, no. 10 (2020): 1030–42, <https://doi.org/10.1080/10962247.2020.1808115>.

<sup>155</sup> Barkley Z. R., et al., (2021) Analysis of Oil and Gas Ethane and Methane Emissions in the Southcentral and Eastern United States Using Four Seasons of Continuous Aircraft Ethane Measurements. *GEOPHYS RES ATMOS* 126, (“In this study, we perform an inverse analysis on 200 h of atmospheric boundary layer C2H6 measurements to estimate C2H6 emissions from the US O&G sector. Measurements were collected from 2017 to 2019 as part of the Atmospheric Carbon and Transport (ACT) America aircraft campaign and encompass much of the central and eastern United States. We find that for the fall, winter, and spring campaigns, C2H6 data consistently exceeds values that would be expected based on EPA O&G leak rate estimates by more than 50%. C2H6 observations from the summer 2019 data set show significantly lower C2H6 enhancements in the southcentral region that cannot be reconciled with data from the other three seasons, either due to complex meteorological conditions or a temporal shift in the emissions. Combining the fall, winter, and spring C2H6 posterior emissions estimate to an inventory of O&G CH4 emissions, we estimate that O&G CH4 emissions are larger than EPA inventory values by 48%–76%.”).

significantly contribute to greenhouse gas emissions.<sup>156</sup> Random and persistent methane plumes that would classify a site as super-emitting may escape accountability under current estimates. The EDF detected 900 methane plumes from over 500 sites in the Permian Basin over an 11-day period, demonstrating that super-emitting sites are still prevalent in the basin.<sup>157</sup>

Commenter (0578-Grand Canyon Trust (GCT)) states recent research estimates that some marginal oil and gas wells emit as much or more gas than they are reported producing.<sup>158</sup> It is also estimated that wells in this lowest production category emit approximately 11 percent of total annual methane emissions in the from oil and gas production, despite that they produce about 0.2 percent of oil and 0.4 percent of gas in the United States each year.<sup>159</sup> Another study from 2018 found that “On average, low NG [natural gas] producing sites emit a larger fraction of their CH<sub>4</sub> production than high NG producing sites.”<sup>160</sup> In their comments, EDF estimates that the 3 tpy threshold would exempt 20 percent of well sites total, 40 percent of which are oil wells and 19 percent of which are gas wells, from regular monitoring, forgoing up to 330,000 tons of methane reductions.<sup>161</sup> As these wells are a significant source of methane pollution, and are found across the country including on the Colorado Plateau, the commenter urges the EPA to strengthen its monitoring requirements to require at a minimum quarterly monitoring at wells including those with baseline emissions less than 3 tpy.

Commenter (0822-TAEP) states while EPA has chosen to reverse its position on the use of production rates to define a threshold to recognize lower regulatory requirements, it should recognize that the DOE funded study of the emissions profile of marginal wells (low production wells) provides data showing that these well sites overwhelmingly fall below the 3 tpy of methane emissions based on actual sampling. However, the framework that the DOE study created in defining the factors that can influence emissions – *e.g.*, production rate, oil or natural gas

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<sup>156</sup> Lin J. C, Bares R., Fasoli B., Garcia M., Crosman E., Lyman S., (2021) Declining methane emissions and steady, high leakage rates observed over multiple years in a western US oil/gas production basin. SCI REP 11, 22291, 1-12, 1 (“Here we present a unique analysis of one of the longest-running datasets of in-situ methane observations from an oil/gas production region in Utah’s Uinta Basin. The observations indicate Uinta methane emissions approximately halved between 2015 and 2020, along with declining gas production. As a percentage of gas production, however, emissions remained steady over the same years, at ~6–8%, among the highest in the U.S. Addressing methane leaks and recovering more of the economically valuable natural gas is critical, as the U.S. seeks to address climate change through aggressive greenhouse emission reductions.”).

<sup>157</sup> McGee M., (23 Sept. 2021) New Aircraft Measurements Once Again Detect High Levels of Methane in Permian Basin, Environmental Defense Fund (last visited 5 Jan 2022) (“The new data was collected during an 11-day period in August by Carbon Mapper as part of EDF’s PermianMAP initiative. The aircraft detected over 900 plumes of methane from more than 500 sources. As with previous surveys of the area, this new data again confirm that super emitting sites continue to be a problem across the Permian.”).

<sup>158</sup> National Library of Medicine. Measurements show that marginal wells are a disproportionate source of methane relative to production. September, 2020. Available at: <https://pubmed.ncbi.nlm.nih.gov/32776822/>.

<sup>159</sup> *Id.*

<sup>160</sup> Mark Omara, Naomi Zimmerman, Melissa R. Sullivan, Xiang Li, Aja Ellis, Rebecca Cesa, R. Subramanian, Albert A. Presto, and Allen L. Robinson. Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate. Environmental Science & Technology. 2018 52 (21), 12915-12925 DOI: 10.1021/acs.est.8b03535. Available at: <https://pubs.acs.org/action/showCitFormats?doi=10.1021%2Facs.est.8b03535&href=/doi/10.1021%2Facs.est.8b03535>.

<sup>161</sup> Based on EDF’s approach, a single pneumatic controller causes emissions to exceed 3 tpy. EPA assumes that approximately 20% of well pads have no pneumatic controllers.

production, number of pieces of equipment at the site – could provide EPA with a framework for the development of an emissions calculation guideline for small businesses and low production well sites.

Commenter (0948-CA Assemblymember Quirk) adds studies by researchers at Carnegie Mellon University and others have shown that these wells have disproportionately high emissions and generate relatively low contributions to national oil and gas production. Subjecting even small, low-production wells and facilities to regular inspections is necessary for mitigating climate impacts.

Commenter (0918-Colorado Local Government Coalition (Colorado LGC)) states low-producing wells are the most abundant type of oil and gas well in the United States, and a surprising number of them are venting all or more than their reported produced gas into the atmosphere.<sup>162</sup> This makes low-producing wells a disproportionate source of VOC and methane emissions compared to their energy production and underscores the need for robust control requirements.

The commenter (0918-Colorado LGC) states a 2020 study involving direct measurements of methane and VOC emissions from marginal oil and gas wells (wells producing less than 1 BOE/d) in the Appalachian Basin of southeastern Ohio found that marginal wells are a disproportionate source of methane and VOCs relative to oil and gas production. The study estimated that oil and gas wells in this lowest production category emit approximately 11 percent of total annual methane production from upstream oil and gas sources in the EPA greenhouse gas inventory, although they produce about 0.2 percent of oil and 0.4 percent of all gas produced in the US per year.<sup>163</sup>

The commenter (0918-Colorado LGC) adds in another recent study involving site-level measurements of over 70 Permian Basin well pads found no relationship between emissions and production. Per the study, wells with production below 10 BOE/d had similar emissions as non-marginal wells, based on a comparison of absolute methane emissions and gas production by site.<sup>164</sup>

The commenter (0918-Colorado LGC) states a 2018 study of sites in eight basins across the US is in accord. Researchers obtained site-level methane emissions data from over 1000 natural gas production sites, including 92 new site-level methane measurements in the Uinta, northeastern Marcellus, and Denver-Julesburg Basins, to investigate methane emissions characteristics and develop a new national methane emission estimate for the natural gas production segment. The study looked at natural gas production sites and categorized them as low (sites producing 1000

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<sup>162</sup> Deighton, Jacob A. et al., Measurements show that marginal wells are a disproportionate source of methane relative to production, 70(10) J. AIR & WASTE MGMT. ASSOC. 1030 (Aug. 2020).

<sup>163</sup> Id.

<sup>164</sup> Robertson et al., New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, 54:21 ENVTL. SCI. TECHNOL. 13926-13934 (2020), <https://pubs.acs.org/doi/10.1021/acs.est.0c02927>.



Mcfd). Low natural gas production sites accounted for 85 percent of the total number of sites in the study and nearly two-thirds (63 percent) of the total methane emissions.<sup>165</sup>

The commenter (0918-Colorado LGC) states several past studies have reported measurement-based results for methane leakage from low production oil and gas wells. These studies varied in geography and scope; while some focused on low-production wells, others measured low production wells as part of a larger measurement campaign that also included non-low production wells. The commenter (0918-Colorado LGC) has identified seven of these studies based on the criteria that they reported both the measured site-level methane emissions and the O&G production data.

The commenter (0918-Colorado LGC) states the studies reveal wide variability in methane leakage rate at the site-level, ranging from 0 to 22 kg/h/site (median = 0.32 kg/h/site = 2.8 metric tpy; average = 1.2 kg/h/site = 10.5 metric tpy). Similarly, as a fraction of their methane production, the data show that methane loss rates from these sites ranged from 0 to >100 percent. More than one-quarter (28 percent) of the measured sites emitted >1 kg/h/site (or > 8.8 metric tpy) and nearly one-third (31 percent) emitted more than 10 percent of their production. The top 5 percent of high emitting sites accounted for approximately 50 percent of the total measured methane emissions, indicating that the phenomenon of “super-emitting” sites that has been observed throughout the O&G supply chain is also prevalent among these low-producing sites.

The commenter (0918-Colorado LGC) notes these studies identified poor maintenance as one of the primary drivers of observed methane leakage at these sites. For example, Deighton *et al.* (2020) observed that the “state of maintenance at these wells was poor;” some sites were in a state of disrepair (*e.g.*, rusty well shafts, broken valves, *etc.*), while others were found to be venting as a result of fallen trees on the wellheads.<sup>166</sup> Similarly, Omara *et al.* (2016) reported “rusted or corroded well casings, field piping, regulators, valves and meters,” and identified a few of these decrepit components as “substantial sources of leaks” at the low-production well sites.<sup>167</sup> These avoidable methane emissions are not well represented in traditional emission factor calculations and contribute to the significant differences that have often been observed between inventory-based estimates and measurement studies.

The commenter (0918-Colorado LGC) states the studies assessed here indicate that low-production wells are likely a disproportionately large source of O&G methane emissions nationally. For example, for the very low production category of 0-1 boe per day wells, Deighton *et al.* (2020) estimate that these wells account for 11 percent of the production-related methane emissions in the EPA’s GHGI. Similarly, Omara *et al.* (2018) estimated that 63 percent of production-related methane emissions come from well sites that produce <100 Mcfd. Therefore,

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<sup>165</sup> Omara, M. et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, 52 ENVTL. SCI. TECHNOL. 12915 (Sept. 2018).

<sup>166</sup> Deighton, Jacob A. et al., Measurements show that marginal wells are a disproportionate source of methane relative to production, 70(10) J. AIR & WASTE MGMT. ASSOC. 1030 (Aug. 2020).

<sup>167</sup> Omara, M. et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, 52 ENVTL. SCI. TECHNOL. 12915 (Sept. 2018).

mitigating the methane emitted from these sites could reduce a significant proportion of oil and gas methane emissions nationally.

The commenter (0918-Colorado LGC) argues these studies demonstrate that controlling low-producing wells is essential to curbing emissions from oil and gas facilities.

Commenter (0918-Colorado LGC) states an analysis conducted through the Boulder County Public Health's oil and gas inspection program concluded that low-producing facilities (*i.e.*, those with tank VOC emissions less than 6 tpy) leak at similar frequencies as larger facilities, supporting proposals to increase LDAR inspection frequencies at these well sites. The commenter cited results from the Boulder County oil and gas inspection program in place since 2014.<sup>168</sup>

The commenter (0918-Colorado LGC) provides a table showing the sites for each of the five years of the program where leaks were detected as well as the cumulative data for all five years of the program.<sup>169</sup> The commenter (0918-Colorado LGC) provides a figure showing the number of sites in Boulder County that experienced one or more leak(s) from 2014 through 2018.<sup>170</sup>

The commenter (0918-Colorado LGC) states in the 2019 AQCC Regulation 7 rulemaking, the Local Government Coalition, which was a party to the hearing, analyzed the frequency of leak occurrence at low producing facilities from the Boulder County LDAR program. The LGC obtained the Division's Air Pollutant Emission Notice (APEN) database containing potential storage tank VOC emissions estimates used during the permitting process. These estimates can classify a well production facility into the corresponding Regulation 7 well production facility LDAR requirements for inspection frequency. A comparison of these estimates with leak frequency over a 5-year inspection period in Boulder County showed little correlation. That is, well production facilities experienced roughly the same rate of leaks across the range of leak inspection frequencies. The commenter provides a table showing Boulder County Voluntary Inspection Program Leak Frequency by Regulation 7 Denver Metro/North Front Range (DMNFR) Ozone Nonattainment Area Storage Tank VOC Threshold.<sup>171</sup> Facilities with greater than one leak did not differ significantly based on production level. In short, low producing facilities leak at similar frequencies as larger facilities.

Response I-7-64: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>172</sup>

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<sup>168</sup> Id. at p. 6.

<sup>169</sup> Between 2014 and 2018, more than 600 oil and gas facility site visits were conducted with an infrared camera for leak detection. Cumulatively, gas leaks were detected at 86% of inspected sites, with the percentage each year ranging from 38% to 49%. 64% of the sites with leaks experienced them in multiple calendar years.

<sup>170</sup> Id. at p. 7.

<sup>171</sup> Rebuttal Statement of the Local Government Coalition, Proposed Amendments to Regulation Number 7 and Regulation Number 22, p. 4-5 (Nov. 23, 2021).

<sup>172</sup> 87 FR 74724-74736 (December 6, 2022).

Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: The commenters (0437-NYOSC, 0918-Colorado LGC, 1388-Private Citizen) believe small wells less than 3 tpy emissions should be monitored often like larger wells. Altogether (or individually) small wells can be massive methane emitters. Requiring only an annual inspection is not sufficient and will result in months of undetected fugitive emissions.

Commenter (0437-NYOSC) believes the November 2021 Proposal only partially meets investors' expectations for a robust rule that fully addresses methane emissions. The commenter urges the EPA to expand monitoring requirements to require regular inspection and repair of leaks from wells with low production rates (those with estimated annual emissions of 3 tpy or less). These smaller wells can be a significant source of methane emissions and regular inspections are needed to ensure that leaks at these sources are detected and stopped.<sup>173</sup>

Response I-7-65: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>174</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) opposes the November 2021 Proposal's baseline requirements for fugitive emissions at well sites with fugitive emissions between 0 and 3 tpy. Establishing a substantive requirement would require an air quality permit in West Virginia and would impose a burden on the state and the sources it regulates without providing any air quality benefit because there is not any proposed control following the baseline measurement. This is a bureaucratic overreach.

Commenter (0424-WVDEP) believes in the final EG OOOOc low production well sites should be exempt from the rule along with individual homeowners, farmers, and very small businesses. The designated facility category for fugitive emissions at well sites between 0 and 3 tpy should be eliminated in the final rule because low production wells should be exempt. Additionally, the commenter objects to the November 2021 Proposal to repeal the amendments in the 2020 Technical Rule that exempted low production well sites from monitoring fugitive emissions under the NSPS.

Response I-7-66: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>175</sup>

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<sup>173</sup> Zavala-Araiza, Daniel, et.al. "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," Environmental Science and Technology, 49, 13, 8167-8174, 2015/.

<sup>174</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>175</sup> 87 FR 74724-74736 (December 6, 2022).

Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0446-Artex) states EPA relied on potentially suspect data to conclude that “fugitive emissions at any given site is impacted more by the number and type of equipment at the site and maintenance practices, which can vary widely among well sites with low production.”<sup>176</sup> To support this claim, EPA cites an October 2020 study<sup>177</sup> in which 29 of the 71 “successful” measurements were actually below the detection limit (BDL). A study in which over 40 percent of the measurements are BDL does not meet minimum data quality standards for a rulemaking of this magnitude. The only other study cited in support of EPA's claim actually arrives at the opposite conclusion, “finding a reduced but still significant prevalence of OGI-detectable emissions at complex marginal wellpads”<sup>178</sup> where “Classification of marginal vs non-marginal wells followed the criterion of 15 barrels-of-oil equivalent (BOEd) production...”<sup>179</sup> Since EPA's own sources establish a correlation between production and emission rate, the commenter requests that EPA retain the exemption for low-production well sites currently codified at 40 CFR 60.5397a(1)(i) and (ii) in NSPS OOOOa and that EPA include this same exemption in NSPS OOOOb.

Response I-7-67: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>180</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0598-Countrymark Energy Resources, LLC (CER)) states the first way to relieve the compliance burden on Small Entity Representatives (SER) is to provide a path to remove affected facilities (well sites, tank batteries, and/or compressors) from monitoring when the PTE is low. As EPA has noted in the preamble, there is a point where the environmental benefits do not exceed the cost of completing the inspections and reporting requirements. To remain consistent with EPA's proposed structure, the commenter recommends when wellsite emissions fall below 3 tpy, monitoring and reporting requirements may be eliminated (eliminated for both the well site and associated tanks). The commenter further recommends that any tank battery that falls below 7.2 tpy (6 tpy VOC and 1.2 tpy methane) have monitoring and reporting requirements be eliminated. Monitoring and reporting requirements will not be required for the affected facilities until the facility meets EPA's definition of a “modification,” whereby monitoring and reporting activities will begin again.

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<sup>176</sup> 86 FR 63187.

<sup>177</sup> New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Anna M. Robertson, Rachel Edie, Robert A. Field, David Lyon, Renee McVay, Mark Omara, Daniel Zavala-Araiza, and Shane M. Murphy Environmental Science & Technology 2020 54 (21), 13926-13934, DOI: 10.1021/acs.est.0c02927.

<sup>178</sup> Methodology for EDF's Permian Methane Analysis Project (PermianMAP), November 17, 2021, [https://www.edf.org/sites/default/files/documents/PermianMapMethodology\\_1.pdf](https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf) (accessed 1/20/22).

<sup>179</sup> Ibid.

<sup>180</sup> 87 FR 74724-74736 (December 6, 2022).

Response I-7-68: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>181</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0573-KDHE) opposes the proposed baseline requirements for fugitive emissions at well sites with fugitive emissions between 0 and 3 tpy. Establishing a substantive requirement would require an air quality permit in Kansas and would impose a burden on the state and the sources it regulates without providing any air quality benefit because there are not any proposed controls following the baseline measurement.

Response I-7-69: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>182</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) states requiring an initial OGI survey to demonstrate non-leaking status for well sites with baseline PTE emissions less than 3 tpy of methane assumes that the newly constructed or modified facilities are out of compliance, which is not typical in the commenter’s NSR authorization mechanisms. The EPA has not indicated how this reporting will be accomplished and how an enforceable limit can be implemented at an affected facility. Commenter (0763-TCEQ/RRC) requests that EPA confirm the recordkeeping, monitoring, and reporting requirements under these rules are sufficient to meet the periodic and sufficiency monitoring requirements of Title V.

Response I-7-70: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>183</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0577-KIOGA) states in January 2021, the International Energy Agency (IEA) released a regulatory roadmap and toolkit focused on “Driving Down Methane Leaks from the Oil and Gas Industry.” The roadmap details that, “understanding the nature and magnitude of your emissions will be critical to designing sound regulations.” This is a primary tenet of what the commenter seeks to convey with the Biden Administration. One key aspect of the independent component of the oil and natural gas production industry is its breadth – spanning

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<sup>181</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>182</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>183</sup> 87 FR 74724-74736 (December 6, 2022).

from large, high production wells to low production wells. These wells do not all have the same emissions profiles, and those different profiles should be considered in regulations.

The commenter (0577-KIOGA) states low production wells are those that produce 15 barrels/day (or 90 mcf/d) or less. The national average low production oil well is about 2.5 barrels/day and the low production natural gas well is about 24 mcf/d. Of the roughly one million active oil and natural gas wells in the United States, about 750,000 are low production wells, typically operated by small businesses. The regulatory structure applied to low production wells is significant because their viability is so dependent on their cost of operation.

The commenter (0577-KIOGA) notes the 2016 EPA NSPS fugitive emissions regulations created a specific problem for low production wells. When EPA developed its fugitive emissions requirements, it generated its BSER technology based on large, hydraulically fractured well sites and its initial proposal applied only to these sites. However, in finalizing the fugitive emissions regulations, EPA expanded their scope to include low production wells, but it never revised the BSER requirements to reflect this broader application. The high production well LDAR program is economically infeasible for low production wells and provides minimal environmental benefits. EPA agreed to reconsider the low production well impact of its fugitive emissions program. In its 2020 revisions to the NSPS, the fugitive emissions program now provided an off-ramp when well sites fall below 15 barrels/day. The implications for low production wells are further compounded by the decision to base the EPA regulatory program on managing methane. Under the CAA, the choice of regulating methane can trigger a nationwide existing facility regulation that would apply EPA BSER technology to the 750,000 low production wells currently in operation.

The commenter (0577-KIOGA) adds industry does not question the need to cost effectively manage its emissions. Many independent producers participate in voluntary actions to reduce emissions — including fugitive emissions.

The commenter (0577-KIOGA) argues industry seeks to find a regulatory pathway designed for the sources it regulates. The 2016 NSPS fugitive emissions program that was designed for large facilities should not be applied to low production well sites. The 2020 NSPS reconsideration moved to correct that error. EPA followed the path it used in its October 2016 Control Techniques Guidelines for low production wells when it excluded them from its model fugitive emissions program. There may be an appropriate low production well program. When EPA developed its NSPS regulations, it had no emissions profile for low production wells. The U.S. DOE initiated a study of low production well air emissions that was completed at the end of 2021. Results from the DOE third-party methane emission study of low production wells and facilities indicate no quantifiable or measurable emissions from wells or tank facilities. If EPA needs to design a low production well program, it should utilize the emissions profile information developed by the DOE and then focus on the most cost-effective options to address the key sources.

Response I-7-71: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii

of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>184</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0577-KIOGA) opposes the proposed baseline requirements for fugitive emissions at well sites with fugitive emissions between zero and 3 tpy. This action would impose significant burdens and costs without providing any air quality benefit.

Response I-7-72: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>185</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0431-NuEnergy) states the best way to keep stripper wells producing is for the EPA to continue to exempt wells that produce less than 15 barrels per day from complying with methane emissions. Otherwise, those wells would likely be plugged rather than spend the capital to comply.

Response I-7-73: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>186</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0425-Darrah Oil Company, LLC (Darrah)) states wells that are low producers of the hydrocarbon products are also low producers of methane. The information that suggested that they are disproportionately large emitters has been proven to be wrong by the DOE among others, but the ghost of this idea lives on. These are the wells that can least afford monitoring and are the lessor of the sources. Most states already have definitions of “stripper wells” that allow them to extend the last few years of a well’s economic life. It would benefit the EPA not to waste resources on these margins and it should adopt exemptions for wells that states define as stripper wells. An outright exemption would eliminate confusion for state regulations that are expected to regulate them.

Response I-7-74: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>187</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

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<sup>184</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>185</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>186</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>187</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0822-TAEP) supports the concept of using a 3 tpy low production facility exclusion from the quarterly LDAR program but recommends an annual AVO (audio, visual, olfactory) review rather than the OGI EPA program. However, it is essential that EPA recognize that most of the well sites falling below 3 tpy will be operated by small businesses and small businesses that are currently below the 25,000 tpy of CO<sub>2</sub>eq reporting threshold (1,000 tpy of methane) for the GHGI. Consequently, EPA needs to develop, in concert with the Small Business Administration, a straightforward guideline document for use in determining whether a site is below 3 tpy of methane. This guideline document should be developed prior to the planned supplemental proposal for subparts NSPS OOOOb and EG OOOOc and subject to comments during that proposal.

Response I-7-75: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>188</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenters (0444-Damascus Citizens for Sustainability (DCS), 0538-Change Finance, 0770-Northern Plains Resource Council (NPRC)) urge EPA to craft a regulation that includes all potentially significant sources of methane emissions, including smaller or low-emitting wells.

The commenter (0444-DCS) is concerned about the November 2021 Proposal to only monitor air pollution at so-called "low-emitting wells" once a year. Special attention must be given to sites where air pollution is assumed to be low. Penn State University concluded that the EPA underestimates methane pollution from the gas industry by 48 to 76 percent. The commenter believes EPA should establish accurate, real-time air pollution monitoring systems at new and existing well sites. EPA must continue to conduct this air monitoring as wells age because EPA correctly states in the proposed rulemaking that the majority of avoidable air pollution at gas wells is caused by aging, unmaintained equipment.

The commenter (0444-DCS) urges the EPA to go further to ensure public health is prioritized, frontline communities are protected, climate emissions are addressed, and oil and gas companies are held accountable. The new rule will also go a long way to meeting US obligations under the Global Methane Pledge, which requires a reduction of methane emissions by 30 percent by 2030.

Response I-7-76: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>189</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

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<sup>188</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>189</sup> 87 FR 74724-74736 (December 6, 2022).



Comment: Commenter (0785-John Crane Inc.) notes that in cases where the advanced measurement technology has been field-proven and has demonstrated commercially and academically the ability to provide accurate emissions quantification (and not just detection) at a level below the 3 tpy threshold, it should be acceptable to use it as an appropriate alternative to OGI for all emissions rates. Given that OGI and EPA Method 21 may not find all leak sources, and therefore would not be appropriate for detection when large leaks have been found, the commenter proposes that EPA Method 21 is no longer appropriate alternative to routine OGI surveys.

Response I-7-77: See discussion in section IV.B.3 of the December 2022 Supplemental Proposal.<sup>190</sup> For the final rule, EPA maintains that EPA Method 21 is a valid alternative to OGI surveys. See section X.B.1 of the preamble to the final rule for description of the final rule requirements. The EPA disagrees with the commenter that OGI and EPA Method 21 are not appropriate for detection when large leaks have been found. Both methods have routinely been used to find small and large leaks.

#### ***7.1.6 Well Sites with Baseline Emissions $\geq 3$ tpy***

Comment: Commenters (0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-UTE EPD, 0943-Sault EPD, 0391-KBIC) support quarterly monitoring versus semiannual monitoring for well sites between 3 and 8 tpy.

Response I-7-78: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>191</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0777-Ascent) believes that semiannual monitoring is appropriate for well sites with baseline methane emissions below 8 tpy and represents a reasonable balance of the cost and burden associated with conducting fugitive monitoring surveys and the potential emissions reductions from these smaller sites with lower fugitive component counts.

Response I-7-79: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>192</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0795-Allergy & Asthma Network) states EPA must strengthen the rule to ensure that small wells are included in frequent regular inspection and repair requirements. At

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<sup>190</sup> 87 FR 74747 (December 6, 2022).

<sup>191</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>192</sup> 87 FR 74724-74736 (December 6, 2022).

a minimum EPA must ensure that sites with estimated emissions between 3 and 8 tpy are subject to the same frequency of inspection as those with estimated emissions above 8 tpy.

Response I-7-80: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>193</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) states EPA should at minimum finalize quarterly monitoring at all sites above 3 tpy, but should also require more frequent monitoring, especially at the largest sites.

Commenter (0844-EDF *et al.*) supports EPA's November 2021 Proposal to require quarterly monitoring at sites above 8 tpy. Quarterly monitoring, and in many cases more frequent monitoring, is in the commenter's opinion well-justified, cost-effective, and necessary to achieve substantial emission reductions. The commenter believes EPA should require at minimum quarterly monitoring at all sites where it is cost-effective, including those from 3 to 8 tpy and all or at least some sites below 3 tpy.

The commenter (0844-EDF *et al.*) believes at large sites, where an abnormal process event could emit even more massive amounts of pollution into the air, quarterly monitoring may not be sufficient, and EPA should therefore require monthly monitoring where it is cost-effective to do so.<sup>194</sup> Leaving such events undetected and unrepaired for multiple months at a time could have devastating climate and health impacts.<sup>195</sup> By EPA's own analysis, monthly monitoring at these sites is extremely cost-effective, even resulting in cost savings for the largest sites.<sup>196</sup> It is arbitrary for EPA to so closely scrutinize cost-effectiveness at the smallest of sites on grounds that those sites have lower potential emissions but not require more frequent monitoring at the sites with the highest potential emissions—especially where increased monitoring could be achieved at low or zero net cost.

The commenter (0844-EDF *et al.*) states it is also incrementally cost-effective to increase monitoring from quarterly to monthly at sites above 20 tpy.<sup>197</sup> EPA should more granularly evaluate whether it might be incrementally cost-effective to increase to monthly monitoring at sites between 15 and 20 tpy. EPA should also evaluate the incremental cost-effectiveness of increasing to bi-monthly (six times per year) monitoring.

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<sup>193</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>194</sup> Our modeling with FEAST, discussed more below, shows that monthly monitoring is highly effective at reducing super-emitter events. See Attachment L (FEAST National Slides).

<sup>195</sup> See, e.g., Conley et al., Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA, 351 Science 1317 (2016), <https://www.science.org/doi/10.1126/science.aaf2348>.

<sup>196</sup> TSD at Table 12-13a, 12-13b.

<sup>197</sup> TSD at Table 12-13c.

The commenter (0844-EDF *et al.*) notes the D.C. Circuit has repeatedly held that section 111 requires the “maximum practicable degree” of control.<sup>198</sup> The CAA does not necessarily require EPA to set a standard at a level that reflects the maximum level of control that is technologically possible, but it does require the agency to maximize the level of emission reductions that can be achieved while giving reasonable consideration to the other statutory factors.<sup>199</sup>

The commenter (0844-EDF *et al.*) continues, with regard to costs, this means that the standard must achieve the maximum degree of emission reductions without becoming exorbitantly costly or ruinous for the regulated industry.<sup>200</sup> Monthly monitoring at the highest tpy sites is well within the range EPA has deemed reasonable; in some cases, it even results in negative costs, while achieving at least 10 percent more emission reductions than quarterly monitoring and even better results if super-emitter reductions are considered. EPA should thus require monthly monitoring at any site where it is cost-effective.

Response I-7-81: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>201</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0564-AIPRO) proposes that the agency delay further proposed rulemaking until the DOE concludes its study on marginal well emissions and the EPA is able to consider the DOE conclusions in its proposed rule. If based solely on fugitive emissions PTE or actuals, the commenter supports the November 2021 Proposal for well sites with baseline emissions between 3 and 8 tpy of semiannual OGI surveys, as well as quarterly OGI surveys for sites above 8 tpy.

The commenter (0564-AIPRO) believes that a 3 tpy site-wide baseline methane emissions triggering quarterly LDAR survey frequency is not practical, overly burdensome, not cost-effective and, most importantly, will not accomplish meaningful fugitive emissions reductions.

Response I-7-82: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>202</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

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<sup>198</sup> *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 437 (D.C. Cir. 1973) (citing Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970, 116 Cong. Rec. 42384, 42385 (1970)).

<sup>199</sup> *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981); see also *id.* at 326 (a standard of performance must “reduc[e] emissions as much as practicable.”).

<sup>200</sup> See *Essex Chemical Corp.*, 486 F.2d at 433; *Portland Cement Ass’n*, 513 F.2d at 508; *Lignite Energy Council*, 198 F.3d at 933.

<sup>201</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>202</sup> 87 FR 74724-74736 (December 6, 2022).

Commenter (0573-KDHE) believes quarterly OGI monitoring for site-level methane thresholds of  $\geq 3$  and  $< 8$  tpy is too burdensome for smaller producers. The commenter recommends the frequency be lowered to semiannual, as in the November 2021 Co-Proposal.

Response I-7-83: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>203</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

### **7.1.7 Monitoring Costs**

Comment: Commenter (0844-EDF *et al.*) indicates that fugitive monitoring is generally very low cost, and in many cases may lead to cost savings from captured gas. Recent reports have identified oil and gas methane mitigation as a crucial near-term opportunity to limit climate warming that can be accomplished at low cost with available technologies and practices, making it the low-hanging fruit of climate action. For fugitive monitoring specifically, costs are extremely low, particularly in comparison to control techniques required in other sectors.<sup>204</sup> The commenter provides extensive input on fugitive monitoring costs and cost-effectiveness.

The commenter (0844-EDF *et al.*) cites to the IEA who recently found that “more than 70 percent of [global oil and gas methane] emissions can be abated with existing technologies” and “the cost of mitigation is often lower than the market value of the gas that is captured.”<sup>205</sup> The IEA estimates that “almost 45 percent of oil and gas methane emissions can be avoided with measures that would come at no net cost,” and identifies LDAR standards as one of the most important measures.<sup>206</sup> The IEA's analysis assumes quarterly monitoring occurs at all sites, but it also finds that “new and emerging technologies—including continuous monitoring sensors, aircraft, drones and satellites—can significantly reduce the cost of detecting fugitive sources when combined with on-site surveys.”<sup>207</sup>

The commenter (0844-EDF *et al.*) also cites to the United Nations Environment Program (UNEP) has similarly found that 60–80 percent of total oil and gas methane emissions can be cut at low cost and that the sector has “the greatest potential for negative cost abatement” because “captured methane adds to revenue instead of being released to the atmosphere.”<sup>208</sup> According to the commenter, A recent UNEP report examines analyses of per-ton abatement costs in the oil and gas sector and finds averages “around US \$1,000 per tonne of methane in the Harmsen

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<sup>203</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>204</sup> 86 Fed. Reg. 63,157 (EPA estimated that total capital costs due to compliance with the proposal would only represent a 0.3% increase for the sector. EPA regulations for EGUs increasing capital expenditures by 15.8% have been upheld as reasonable by the D.C. Circuit. This underscores how minimal any compliance costs are for an industry that spends hundreds of billions annually.).

<sup>205</sup> IEA, *Curtailling Methane Emissions from Fossil Fuel Operations: Pathways to a 75% cut by 2030* (October 2021), <https://www.iea.org/reports/curtailling-methane-emissions-from-fossil-fuel-operations>.

<sup>206</sup> *Id.*

<sup>207</sup> *Id.* at 25.

<sup>208</sup> UNEP, *Global Methane Assessment 96* (May 2021), <https://www.unep.org/resources/report/global-methane> [hereinafter “UNEP Global Methane”].

analyses, near zero in the IEA analysis, and having a net negative cost of roughly US \$700 per tonne methane in the IIASA analysis.”<sup>209</sup> Even the highest of these figures—\$1,000 per ton—is less than half of the cost reported by EPA for the vast majority of the industry.<sup>210</sup> The report further points out that “[IEA] analysis shows that the category with the largest mitigation potential, upstream LDAR, is also the cheapest.”<sup>211</sup>

According to the commenter (0844-EDF *et al.*), numerous studies have shown that over time and with repeated inspections, OGI programs reduce emissions and also help to prevent large emission events.<sup>212</sup> Studies have indicated that repair programs are highly effective where some are finding that more than 90 percent of leaks remained fixed a year later.<sup>213</sup> However, the same study also found that each individual survey reduced a site’s overall fugitive emissions by only 22 percent on average because of new leaks that occurred afterwards, indicating the need for “frequent, effective, and low-cost LDAR surveys to target new leaks” and a “more definitive classification of leaks and vents.”<sup>214</sup>

The commenter (0844-EDF *et al.*) believes that EPA’s methodology for calculating costs of the OGI program generally overestimates costs, thereby underestimating cost-effectiveness. When coupled with the failure to account for large emission events, the LDAR requirements appear much less cost-effective than would actually be true in most situations. The commenter urges EPA to revisit its repair cost assumptions, especially given the changes to the definition of “fugitive emission component” and the updated work practice standards for other sources to ensure they are not overestimates. The commenter is of the opinion that repairs of certain components and equipment that are required to be functioning properly under other work practice standards, *e.g.*, pneumatics, tank control systems, and flares, and cannot be attributed to the costs of fugitive monitoring and repair. The operator is already required to ensure certain components and equipment function properly, so counting those costs in the costs of the LDAR program would be double counting.

The commenter (0844-EDF *et al.*) conducted an in-depth analysis of EPA’s cost analysis. The commenter indicates that if EPA relies on API cost data for reporting, recordkeeping and data management then it should not also include recordkeeping and reporting costs elsewhere in its analysis. Specifically, EPA should remove the \$15,000 per year recordkeeping and reporting costs that are factored into the \$142/hour labor rate for OGI camera surveys. The commenter notes that EPA should adjust its annual report cost to account for the fact that the API cost data includes preparation of the report for submittal to EPA. The three hours of additional labor EPA includes for preparing the annual report and storing/filing records likely double counts API’s costs to review and submit the annual report to EPA.

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<sup>209</sup> Id. at 96.

<sup>210</sup> Id.

<sup>211</sup> Id. at 102.

<sup>212</sup> Wang *et al.*, Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane LDAR Programs at Oil and Gas Facilities, EarthArXiv (2021) (non-peer reviewed preprint), <https://eartharxiv.org/repository/view/2935/>; Ravikumar *et al.*, Repeated LDAR surveys reduce methane emissions over scale of years, 15 *Env. Research Letters* 034029 (2020), <https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf> [hereinafter “Ravikumar 2020”].

<sup>213</sup> See Ravikumar 2020.

<sup>214</sup> Id.

The commenter (0844-EDF *et al.*) adds there are additional reasons to think that API's costs do not accurately reflect current costs associated with the OGI program. The costs provided by API were submitted in 2019, before EPA's 2020 amendments to NSPS OOOOa that streamlined the rule's recordkeeping and reporting requirements. In the 2020 rulemaking, EPA eliminated the requirement to keep various records, including those related to interim repairs and annual reports, and estimated the revisions would save \$1,100 per site annually. The EPA has not explained how the costs submitted by API in 2019 accurately reflect the costs that would be expected to occur under the revised and retained 2020 recordkeeping standards. EPA simply assumed in certain instances that the 2020 revisions would reduce costs by 25 percent.

The commenter (0844-EDF *et al.*) specifically also says that if EPA accounts for travel in the total hours used to calculate OGI camera survey costs, per well site, then it should not also include travel time costs in the labor costs. Two hours per well site for travel time is likely an overestimate, based on survey times in annual compliance reports submitted to EPA. In 2018, MJB concluded that the average time to conduct an LDAR survey is approximately 1.25-1.6 hours per well, including travel time between sites.<sup>215</sup> Specifically, MJB reported an average time between ending a survey at one site and starting a survey at the next site from less than five minutes to more than 2 hours, with an average of 30 minutes.

The commenter (0844-EDF *et al.*) also believes that survey times are also likely overestimated. Based on a review of annual compliance reports submitted to EPA in early 2021, for the approximately 300 upstream LDAR surveys with reported start-and end-time data reviewed, over half took less than 30 minutes to complete and 82 percent took an hour or less. Less than five percent of the LDAR surveys in the reports reviewed took more than 1.5 hours per well site. The average reported time to conduct the LDAR surveys was just over 30 minutes per well site across the data set.

The commenter (0844-EDF *et al.*) highlights that one company submitted 71 reports in the first quarter of 2021 and reported that it completed each of its surveys in exactly one hour. This survey time covered upstream sources, including tank batteries and well pads with up to 30 wells, and is presumably a time period that adequately captures the time spent at these sites. One hour therefore likely overestimates many surveys for well pads with fewer wells. For this company, a one hour survey is reportedly sufficient for all of its first quarter 2021 surveys.

In the commenter's (0844-EDF *et al.*) opinion, annual recordkeeping database maintenance and license fee costs are overestimated. The commenter notes that EPA's OGI costs include a category for annual recordkeeping database maintenance and license fee costs based on the average cost provided to EPA by API.<sup>216</sup> In its memo to EPA, API reports data for two data systems: (1) in-house database and/or spreadsheets; and (2) customized commercial software systems. API reports, and EPA uses, the average of the cost per facility for 29 in-house and 308 customized commercial software systems. The fact that over 90 percent of the facilities in the dataset are using the customized commercial software system should be reflected in the average cost per facility in order to account for the fact that most facilities are using this type of system. The commenter believes EPA should use the weighted average of the data points across all 337

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<sup>215</sup> Attachment C (Memo from MJB to EDF 2018).

<sup>216</sup> EPA- EPA-HQ-OAR-2017-0483-2248\_attachment\_1 (May 22, 2019).

facilities, or \$544/year per facility, instead of the \$868/year per facility cost presented by API, which is the average of the two costs.<sup>217</sup>

The commenter (0844-EDF *et al.*) states that EPA used an average ongoing annual fee of \$470 for its model plant. Applying this same method but using API's weighted average of \$544/year results in an even lower estimate for annual recordkeeping and data management costs, closer to \$300/year.

The commenter (0844-EDF *et al.*) also believes the initial costs to set up a data management program are overestimated. The fact that over 90 percent of the facilities in the dataset are using the customized commercial software system should be reflected in the average setup cost per facility in order to account for the fact that most facilities are using this type of system. EPA should consider the weighted average of the data points across all 337 facilities, or \$1,622 per facility, instead of the \$2,839 per facility cost presented by API.<sup>218</sup> In fact, this cost is more in line with the \$1,500 per facility setup cost assumed by CARB in its 2017 rulemaking for GHG emission standards for oil and gas facilities.<sup>219</sup>

The commenter (0844-EDF *et al.*) indicates that it revised EPA's cost analysis to include:

1. Revised labor rate for OGI camera surveys that removes the recordkeeping, reporting, and travel time costs,
2. Revised annual recordkeeping database maintenance and license fee costs to reflect the weighted average API data, and
3. Revised one-time initial setup costs to reflect CARB's setup cost estimate.

According to the commenter (0844-EDF *et al.*), these changes result in a roughly 20 percent decrease in annual costs per well site. Note, these revised costs likely still overestimate costs as annual reporting costs are included in both additional recordkeeping/data management costs and annual report costs, and the revised costs also likely overestimate both the travel time and survey time assumed for OGI camera surveys. If the time for survey and travel were revised from 3.4 hours to 1.25 hours the well site costs for monthly OGI monitoring (including all of the other revisions described above) would be \$2,493, or roughly 40 percent less than EPA's estimates. The commenter provides Figure 5: Comparison of OGI Cost of Control & Revised Cost of Control.<sup>220</sup>

Using these revised cost assumptions, the commenter (0844-EDF *et al.*) recalculated the cost-effectiveness of OGI monitoring frequencies across the same tiers used by EPA.<sup>221</sup> Specific

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<sup>217</sup>Costs are calculated using API data, as follows:  $\$36,500/29 \text{ facilities} = \$1,259/\text{facility}$  for in-house systems  $\$147,000/308 \text{ facilities} = \$477/\text{facility}$  for customized commercial systems Weighted average:  $(\$1,259/\text{facility} * 29 \text{ facilities}) + (\$477/\text{facility} * 308 \text{ facilities}) / (29 + 308) = \$544/\text{facility}$ .

<sup>218</sup> Costs are calculated using API data, as follows:  $\$125,000/29 \text{ facilities} = \$4,310/\text{facility}$  for in-house systems  $\$421,500/308 \text{ facilities} = \$1,369/\text{facility}$  for customized commercial systems Weighted average:  $(\$4,310/\text{facility} * 29 \text{ facilities}) + (\$1,369/\text{facility} * 308 \text{ facilities}) / (29 + 308) = \$1,622/\text{facility}$ .

<sup>219</sup> CARB, Cost Estimates (2017), <https://www.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm>; CARB, Attachment 2, (2016), <https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasatt2.pdf>

<sup>220</sup> Attachment E (EPA OGI Cost Analysis - well sites).

<sup>221</sup> See Attachment E (EPA OGI Cost Analysis - well sites).

details can be found in the commenter's letter and attachments. As noted above, these are conservative estimates based on reduced costs per well site of 20 percent. If EPA revised travel time and time for the survey, the cost per well site would be reduced by about 40 percent, which results in an even greater cost-effectiveness. The commenter provides tables with additional information in their commenter letter.

The commenter (0844-EDF *et al.*) believes that EPA should consistently apply its cost-effectiveness calculations and questions why EPA does not explain why it evaluated cost at granular level for smaller sites, but not at larger sites. With very small calculated baseline emissions such as 1 tpy, control measures appear less cost-effective. The commenter believes this methodology is inappropriate and places undue emphasis on cost-effectiveness at the smallest sites. Nevertheless, EPA found quarterly monitoring at 2 and 3 tpy sites to be within its accepted cost-effectiveness range.<sup>222</sup>

The commenter (0844-EDF *et al.*) believes the granularity skews the analysis to disfavor monitoring at lower tpy sites, yet there is no guarantee that these sites will remain below a given tpy threshold. If EPA retains this granularity at lower tpy sites, it should evaluate higher tpy sites the same way and examine whether more frequent monitoring is justified at those sites, including by evaluating bi-monthly monitoring. If the majority of sites within a given tier (*i.e.*, 1-3 tpy) can be monitored cost-effectively, then EPA should require monitoring at all the sites within that tier or otherwise adjust its parameters. The commenter asserts that it is arbitrary for EPA to exclude an entire tier of sites consisting of 3 tpy increments from regular monitoring because it found that monitoring at only one tpy increment within the tier would not be cost-effective.

The commenter (0844-EDF *et al.*) emphasizes that cost, which must only be "reasonable" under section 111 of the CAA is only one factor EPA must examine when setting BSER, and EPA may not elevate costs over other statutory factors, such as the quantity of emission reductions achieved by a particular system. Nor does section 111 require EPA to use any particular approach to evaluate whether costs are reasonable. Thus, in this case EPA could evaluate LDAR costs by simply averaging cost-effectiveness across tpy tiers and setting BSER applied to all sites within a given range. It would be reasonable for EPA to assume that the average operator owns a diverse array of sites, spanning the different tpy tiers, and that the average 22-site area consists of sites spanning the tpy tiers. The commenter thinks that EPA could therefore assume that costs would be spread across those sites, allowing for higher costs at certain sites that would be offset by lower costs at others. Finally, EPA should not elevate its incremental cost-effectiveness analysis over more important considerations, such as emission reductions.

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<sup>222</sup>86 Fed. Reg. 63189 ("[F]or sites with total baseline methane emissions of 2 tpy, we conclude that regular monitoring at semiannual or quarterly frequencies would be cost-effective."); see also *id.* at 63,155 ("EPA finds the cost-effectiveness values up to \$1,800/ton of methane reduction to be reasonable").



The commenter (0844-EDF *et al.*) adds that cost-effectiveness estimates from leading states are much lower than EPA's, *e.g.*, Colorado.<sup>223,224</sup> Colorado's 2021 rulemaking used hourly inspection rates of \$105 for in-house and \$137 for contractors, as well as an hourly repair cost of \$82.06 to generate cost-effectiveness estimates.<sup>225</sup> The commenter relied on these assumptions (with a slightly shorter repair timeline) and the EDF Methane Policy Analyzer to generate adjusted cost-effectiveness estimates based on the 2021 Colorado rulemaking.<sup>226</sup> These estimates generally employ the Colorado Air Pollution Control Division's methodology but reflect the commenter's alternative proposal as part of the Colorado rulemaking to require monthly screening at all well sites and all compressor stations in Colorado (as opposed to the tiered structure that was ultimately adopted). Under the alternative proposal operators would choose between monthly advanced screening (paired with annual or semiannual Approved Instrument Monitoring Method (AIMM) or monthly AIMM). The commenter includes *Figure 7: EDF-Adjusted Cost-Effectiveness Estimates Based on CO 2021 Methodology*.<sup>227</sup>

The commenter (0844-EDF *et al.*) notes that CARB cost estimates are also lower than EPA's. In 2016, CARB estimated that quarterly monitoring cost \$23-\$75 per ton of CO<sub>2</sub>e reduced using 20-and 100-year GWP, with and without gas savings.<sup>228</sup> CARB used \$60/hr for labor, based on the average of contractor data points it gathered (\$55, \$70, \$62, \$55, \$50).<sup>229</sup> CARB also assumed \$1,500 per facility to account for setup costs.<sup>230</sup>

The commenter (0844-EDF *et al.*) states that publicly available cost estimates are much lower than EPA's and are around \$500-600 per well site.<sup>231</sup> Data from oil and gas producing companies and methane mitigation companies consistently confirm the cost of LDAR surveys are even lower. One company, Jonah Energy, documented a 75 percent reduction in leak

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<sup>223</sup>Colorado Air Quality Control Commission, Cost-Benefit Analysis (Nov. 29, 2019), <https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf>.

<sup>224</sup>Well site estimates are drawn from: Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7, pg. 28, Table 34 (Feb. 7, 2014), <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7573>.

<sup>225</sup>Colorado Air Pollution Control Division, Final Economic Impact Analysis for Regs. 7 and 22 (2021), <https://drive.google.com/drive/folders/18e3kQ9heBASpIE5e6-bwzpFOzetxdA2G>.

<sup>226</sup>For a full explanation of the methodology, see EDF, Prehearing Statement, Exhibit 25 (2021) (EDF\_PHS\_EX 025), <https://drive.google.com/drive/folders/1Wr6pbY7NoOXoDwIyXF3vXptF3OLG0gm->.

<sup>227</sup>EDF, Alternative Proposal, Economic Impact Analysis for Regs. 7 and 22 (2021), <https://drive.google.com/drive/folders/1UY2aiAZ8HjsVx7QiFzlxCdZSA4bhs>.

<sup>228</sup>CARB, Attachment 2 (2016), <https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasatt2.pdf>.

<sup>229</sup> *Id.*

<sup>230</sup> *Id.*

<sup>231</sup>Kemp & Ravikumar, New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, but Policies Will Require Careful Design to Establish Mitigation Equivalence, 55 *Env. Sci. Tech* 9140 (2021) <https://pubs.acs.org/doi/10.1021/acs.est.1c03071>; EPA Methane Detection Technology Workshops (Presentations of Arvind Ravikumar and Erin Tullos), available at, <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0181>; Ravikumar & Lyon, Impact of survey frequency on emissions mitigation at oil and gas sites, Appendix D (December 2018), [https://www.edf.org/sites/default/files/content/Appendix\\_D\\_Ravikumar\\_and\\_Lyon\\_Impact\\_of\\_Survey\\_Frequency\\_on\\_Emissions.pdf](https://www.edf.org/sites/default/files/content/Appendix_D_Ravikumar_and_Lyon_Impact_of_Survey_Frequency_on_Emissions.pdf).

detection over five years in Wyoming.<sup>232</sup> Jonah Energy also found that total LDAR program costs decreased from \$99 per inspection in the first year to \$29 per inspection in the fifth year.<sup>233</sup> Further, in each year, the total value of the captured gas across Jonah Energy's operations offset LDAR survey costs by at least \$10,000, including one year where the captured gas resulted in more than \$90,000 net in savings.<sup>234</sup>

Lastly, the commenter (0844-EDF *et al.*) points out that Texas-based Rebellion Photonics has stated that its own leak detections services cost \$250 per site.<sup>235</sup> FLIR Systems reports that LDAR inspections conducted by third-party service providers may cost as little as \$141 per site, which is far lower than EPA's estimate.<sup>236</sup> Based on its own data, Target Emission Services found that LDAR monitoring costs for compressor stations are \$1,220, inclusive of onsite monitoring, travel expenses, and reporting, per survey.<sup>237</sup>

Response I-7-84: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>238</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0597-Indiana Oil & Gas Association (INOGA)) advocates that EPA perform a cost effectiveness analysis at multiple points during the life of a well to determine when the additional regulatory requirements can no longer be economically justified. While EPA may consider this analysis to be burdensome, the proposed regulations will be far more burdensome for the commenter's members as they are required to implement new requirements that substantially increases their operating costs for the entire life of each asset.

Response I-7-85: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii

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<sup>232</sup>Wyoming Public Media, WY Approves Strict Air Pollution Regs for Pinedale (2015), <http://wyomingpublicmedia.org/post/wy-approves-strict-airpollution-regs-pinedale>.

<sup>233</sup>EDF, Finding, fixing leaks is a cost-effective way to cut oil and gas methane emissions (2016), <http://www.methanefacts.org/files/2016/05/LDAR-Fact-Sheet-FINAL.pdf> (citing WCCA Spring Meeting, Jonah Energy Presentation, May 8, 2015 delivered by Paul Ulrich. It is unclear if this assumed one or two well sites per inspection.).

<sup>234</sup>The first year resulted in a net savings of \$22,159, \$10,955 in the second year, \$90,577 in the third year, \$41,256 in the fourth year, and \$28,691 in the fifth year.

<sup>235</sup>Rebellion Photonics comments at the EPA public hearing on the proposed NSPS OOOOa rule in Dallas, TX on September 23, 2015, [https://www.edf.org/sites/default/files/content/attachment\\_1\\_-\\_rebellion\\_epa\\_hearing\\_testimony.pdf](https://www.edf.org/sites/default/files/content/attachment_1_-_rebellion_epa_hearing_testimony.pdf).

<sup>236</sup> FLIR Systems, (Apr. 22, 2016) <https://www.regulations.gov/?elq=3ff5b8047ab24463aa9991e03f221745%26elqCampaignId=1306#!documentDetail;D=BLM-2016-0001-9035>.

<sup>237</sup> Terence Trefiak, Target Emission Services, NSPS OOOOa Monitoring Case Study (Mar. 7, 2018), Docket ID No. EPA-HQ-OAR-2017-0483-0031.

<sup>238</sup> 87 FR 74727-74729 (December 6, 2022).

of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>239</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0955-Vaquero Energy Inc. (Vaquero)) requests that for wells that do not meet the November 2021 Proposal’s categorical exemption, EPA revise the cost effectiveness data. EPA has used a linear model to predict the reduction in emissions from increasing the inspection frequency. However, EPA estimates that the costs will not increase linearly. The commenter states that if inspection frequency doubles, inspection cost will at least double. The commenter believes EPA has also significantly underestimated the cost for inspection. Hiring an out-of-state contractor with an OGI camera to perform inspections will be twice the cost if inspections are performed twice as many times per year, not 7 percent greater (\$3,200 Semiannual inspection cost / \$3,000 Annual inspection cost = 7 percent).

Response I-7-86: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>240</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0835-Center for Methane Emissions Solutions (CMES)) believes EPA has miscalculated LDAR costs. As the leading organization of methane mitigation companies in the United States, the commenter claims it is uniquely suited to convey to the Administration an accurate accounting of the true costs associated with implementing an OGI LDAR program.

For example, the commenter (0835-CMES) believes EPA has significantly increased cost estimates of “annual recordkeeping database maintenance and license fee” and “additional recordkeeping/data management costs.” According to assumptions provided to the Agency, EPA suggests that costs associated with recordkeeping is responsible for an increase of \$700 in monitoring costs since 2020. The commenter notes that these assumptions are inaccurate. For example, one nationally recognized member of the commenter’s organization provides recordkeeping to its customers as part of their standard agreement and estimates the cost at about \$50. The commenter encourages EPA to revise this estimate because recordkeeping is likely already included in service contracts, and that readily available technology makes such a task cost-effective.

Response I-7-87: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>241</sup>

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<sup>239</sup> 87 FR 74727-74729 (December 6, 2022).

<sup>240</sup> 87 FR 74727-74729 (December 6, 2022).

<sup>241</sup> 87 FR 74727-74729 (December 6, 2022).

Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0959-Colt Midstream LLC (Colt)) states the November 2021 Proposal would make it difficult for small and midsize operators to have in-house individuals trained to perform the surveys as well. The number surveys, approximately 100, where a trainer and trainee are required to perform together creates a burden for operators who may not have the quantity of facilities or personnel to meet the 100 surveys required prior to field testing. The additional requirement for the senior survey personnel to require having 500 documented surveys to act as trainer is a burden. Most companies just starting a program may have a difficult time acquiring this person.

Response I-7-88: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>242</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions from well sites.

Comment: Commenter (0844-EDF *et al.*) states because EPA found quarterly monitoring at sites as low as 2 tpy cost-effective,<sup>243</sup> it should at least extend quarterly monitoring requirements to those sites. EPA acknowledges that regular monitoring at certain sites below 3 tpy would be cost-effective, but states that “[c]ost-effectiveness, however, is not the only relevant factor in setting the BSER, particularly for a source as numerous and diverse as well sites.”<sup>244</sup> But EPA’s stated rationales under the other BSER considerations are not supported by the record. EPA states that “[v]arious studies demonstrate that the vast majority of emissions come from a relatively small subset of wells,” and because of this, “EPA would like to ensure that resources and effort are focused on those wells that emit the most methane and VOC.”<sup>245</sup> While focusing resources on mitigating the greatest sources of emissions makes sense, that is no justification to categorically exempt other important sources from regular monitoring requirements.

The commenter (0844-EDF *et al.*) states there is no evidence of a shortage of resources. Most information available suggests that there are ample resources and that methane mitigation services are widely available and rapidly growing.<sup>246</sup> A recent report from Datu Research provides a comprehensive survey of the U.S. methane mitigation industry.<sup>247</sup> This report shows that this is a rapidly growing industry—finding a 90-percent increase in services firms over the

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<sup>242</sup> 87 FR 74727-74729 (December 6, 2022).

<sup>243</sup> 86 Fed Reg. 63189.

<sup>244</sup> 86 Fed. Reg. 63189.

<sup>245</sup> 86 Fed. Reg. 63189-90.

<sup>246</sup> Datu Research, Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry (2021), <https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf> [hereinafter “Datu 2021”]; Marcy Lowe, Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up, Datu Research (July 22, 2021), [http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey\\_Datu246Research\\_8-10-2021.pdf](http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_Datu246Research_8-10-2021.pdf).

<sup>247</sup> Datu 2021 at 8.

2017 report<sup>248</sup>, and deeming these numbers “almost certainly an undercount in all manufacturing and service categories.”<sup>249</sup> The commenter notes the following key findings:

- The industry comprises dozens of job types, with annual salaries ranging from \$37,150 to \$140,960.
- Most of the firms (70 percent) are small businesses.
- Nearly 25 percent of the manufacturing firms and over 40 percent of the services firms were founded in the past 12 years.
- Firms are adding new U.S. employee locations. In 2021, Datu identified a total of 748 employee locations for manufacturing and service firms, an increase of 26 percent over the number previously identified.
- Firms anticipate growing jobs. Of 57 firms that responded to Datu’s survey, 75 percent of the manufacturing firms and 88 percent of the service firms reported that if future state or federal methane emission rules were put in place, they would anticipate hiring more employees.
- These jobs appear poised to grow soon, in light of EPA’s November 2021 Proposal and at least eight states preparing to either introduce new methane rules or expand the scope of existing ones.<sup>250</sup>

The commenter (0844-EDF et al.) adds monitoring at smaller sites can also be done cost-effectively. In assessing cost-effectiveness, EPA should recognize that most operators own multiple wells, and EPA should group sites accordingly. In fact, for consistency with its analyses of higher-tpy wells, EPA could simply group all sites below 5 tpy together for cost-effectiveness considerations. But if EPA retains its current approach for lower-emitting sites, it should evaluate cost-effectiveness consistently at the same granularity across lower and higher tpy sites. In particular, EPA should seek to identify the point at which more frequent monitoring—six to twelve times per year—would be cost-effective and designate a separate category for those sites.

The commenter (0844-EDF *et al.*) argues EPA has greatly overestimated the costs of OGI monitoring primarily due to an overestimate of recordkeeping and database management costs, an overestimate in the time necessary to conduct an OGI survey, and double counting of certain cost components. The overestimation of costs makes monitoring at these sites appear less cost-effective than is actually the case. Additionally, many sites below 3 tpy have not been subject to federal air pollution regulation before and will likely have old and failure-prone equipment. Because of this, the commenter expects that many of the sites will contain large leaks when inspected, so monitoring would be more cost-effective than assumed by EPA.

The commenter (0844-EDF *et al.*) states many operators that lack experience complying with federal regulations will simply hire contractors to conduct fugitive monitoring rather than creating an entire in-house program. The same is true for smaller operators who may lack the staff and expertise to conduct fugitive monitoring. In this situation, some of the costs EPA has analyzed are inapplicable or should be reduced. For example, an operator that contracted with an

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<sup>248</sup> Datu Research, Find and Fix: Job Creation in the Emerging Methane LDAR Industry (March 2017), <https://www.edf.org/sites/default/files/find-and-fix-datu-research.pdf>.

<sup>249</sup> See Datu 2021 at Appendix A (full list of firms and offerings).

<sup>250</sup> Datu 2021 at 3.

OGI provider is unlikely to spend any time reading Appendix K or developing a fugitive monitoring plan. They may also contract for recordkeeping and data management services, further reducing costs. EPA should consider these possibilities and analyze costs appropriately.<sup>251</sup>

Response I-7-89: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>252</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0835-CMES) states that as the leading organization of methane mitigation companies in the United States, the commenter is uniquely suited to convey an accurate accounting of the true costs associated with implementing an OGI LDAR program. In reviewing the November 2021 Proposal, the commenter believes that EPA has miscalculated. For example, EPA has significantly increased cost estimates of "annual recordkeeping database maintenance and license fee" and "additional recordkeeping/data management costs." According to assumptions provided to the Agency, EPA suggests that costs associated with record keeping is responsible for an increase of \$700 in monitoring costs since 2020. The commenter (0835-CMES) is pleased to convey that these assumptions are inaccurate. Many methane mitigation service providers offer such services as part of their contract. Separate contracts for such services are highly unusual. Further, one nationally recognized member of the commenter's organization provides recordkeeping to its customers as part of their standard agreement and estimates the cost at about \$50. The commenter encourages EPA to revise this estimate because record keeping is likely already included in service contracts, and that readily available technology makes such a task cost-effective.

Response I-7-90: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>253</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: The commenter (0824-Wyoming Department of Environmental Quality (WDEQ)) disagrees with EPA's assessment that the cost of semiannual monitoring at low production well sites is cost effective for all well site operations in Wyoming. In the commenter's opinion, EPA's assessment ignores other significant such as the cost of OGI equipment needed for monitoring, personnel and contractor costs, and the new proposed Appendix K requirements. New and modified oil and gas sources in Wyoming require sources to utilize Best Available Control Technology (BACT). In 2018, the commenter's analysis found that at a 6 tpy control threshold for VOC, the cost to control VOC using semiannual fugitive emissions monitoring was

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<sup>251</sup> See, e.g., Colorado Air Quality Control Commission, Regulatory Analysis (Dec. 5, 2019), <https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf>.

<sup>252</sup> 87 FR 74727-74729 (December 6, 2022).

<sup>253</sup> 87 FR 74727-74729 (December 6, 2022).

\$12,591/ton, and for quarterly fugitive emissions monitoring, the cost ranged from \$27,855/ton to \$53,076/ton. Based on the cost to control VOC, it was determined semiannual fugitive emissions monitoring was BACT. The commenter recommends that EPA re-evaluate its emission control thresholds and cost-of-controls to fully account for all factors.

Response I-7-91: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>254</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

Comment: Commenter (0808-API) states that EPA's cost analysis erroneously assumes operators would not purchase an OGI camera. As API pointed out in the commenter's December 4, 2015, comment letter on proposed NSPS OOOOa,<sup>255</sup> EPA continues to exclude the cost of an OGI camera within the cost benefit analysis and assumes operators will only rely on third-party contractors to perform OGI monitoring, which is incorrect. The commenter indicates that API survey responses collected by a third-party ranged from \$90,000-\$100,000 for an OGI camera. A conservative assumption would be to include the costs for at least a single OGI camera. Most companies own and operate numerous cameras because it takes a team of LDAR technicians to implement and manage an OGI monitoring program across hundreds to thousands of sites.

Response I-7-92: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>256</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

### ***7.1.8 Audio, visual, and olfactory (AVO)***

Comment: Commenters (0585-Kentucky Oil and Gas Association (KOGA), 0598-CER) support the use of AVO. These commenters suggest this is a low-cost way for small and large businesses to monitor for emissions. Most of the large emission sources may be identified through AVO inspections, without the need to utilize an OGI camera. The OGI cameras are very expensive to purchase and maintain or to hire a qualified contractor to perform the inspections. The commenter (0585-KOGA) recommends that EPA does not include burdensome recordkeeping and reporting for AVO inspections. This is an unnecessary use of employee time and not valuable to EPA. At most, the commenter recommends that operators only need to report on leaks that are identified and repaired through AVO inspections.

Response I-7-93: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the

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<sup>254</sup> 87 FR 74727-74729 (December 6, 2022).

<sup>255</sup> API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776).

<sup>256</sup> 87 FR 74727-74729 (December 6, 2022).

December 2022 Supplemental Proposal. See discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related.<sup>257</sup>

Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites. The EPA is finalizing the work practice standards for monitoring with AVO inspections only for single wellhead only well sites and small well sites and a combination of AVO inspections with OGI (or EPA Method 21) for multi-wellhead only well sites and well sites with major production and processing equipment and centralized production facilities.

### **7.1.9 Small/Marginal Wells**

Comment: Commenters (0727-OSEE/ODEQ, 0810-Petroleum Alliance-OK, 1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*) ask that EPA defer regulating marginal/low production wells until the DOE report on small/marginal wells is published.

Commenter (1422-Senator Marshall *et al.*) states that the DOE will soon release an in-depth analysis on methane emissions produced by marginal wells and the results of that study will be extremely valuable to this rulemaking process. The commenter explains that this federally funded report on the "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" will provide actionable data on how small production operations contribute to global emissions, and preliminary information from the DOE indicate no quantifiable or measurable emissions. The commenter suggests that, with the report due to be released any day now, they believe that there is no justifiable reason to not wait so that the results can be fully considered as part of the rulemaking process.

Comment: Commenter (0603-Representative Arrington *et al.*) urges the EPA to suspend publication of any related proposal until the DOE completes their study titled, "Quantification of Methane Emissions from Marginal Oil and Gas Wells."

Commenter (0603-Representative Arrington *et al.*) states that the objective of this federally funded study is to quantify methane emissions from marginal oil and gas well-sites at various basins across the U.S., including the Permian Basin. Scheduled for public release in December 2021, the report will provide critical data on emissions from low producing wells, which must be considered in any forthcoming EPA Emissions Rule. The commenter states that there is an ongoing debate regarding the efficacy of regulating emissions from low production wells, and it is important to acknowledge key information this study will provide regarding where in the production chain emissions are detectable.

Commenter (0603-Representative Arrington *et al.*) points out that approximately 75 percent of the existing oil and natural gas wells in the U.S. are low producing wells. The commenter notes that any regulatory change will affect the business of thousands of operators, their dependents, as well as state and local revenues that rely on robust energy production. To ensure the EPA promulgates a rule relating to emissions in good faith, publication must be postponed until the ongoing study is finalized, and the study's findings must be taken into consideration during the

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<sup>257</sup> 87 FR 74728-74736 (December 6, 2022).



drafting process. According to the commenter, not only would it be irresponsible to do otherwise, but it would needlessly jeopardize our nation's small and independent oil and gas producers.

Commenter (0603-Representative Arrington *et al.*) states that it is vital that NSPS and EG for the oil and gas sector be cost-effective, reasonable, and based on the best available information.

The commenter (0727-OSEE/ODEQ) believes EPA disregards important forthcoming information on marginal and low-producing wells by proposing to subject said wells to frequent OGI monitoring. EPA should wait to publish any final rule until the report, “Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells,” conducted by the National Energy Technology Laboratory (NETL) has been completed.<sup>258</sup> The final report can help inform EPA on this most recent rulemaking and, specifically, to understand at what point are small and marginal producing wells no longer cost effective to require fugitive monitoring using OGI.

The commenter (0810-Petroleum Alliance-OK) states when EPA developed its NSPS OOOOa regulation for oil and gas, it had no emissions profile for marginal/low production wells; however, EPA proceeded to regulate them with a limited data set. Currently, EPA still has a limited data set that fully characterizes these types of wells. The DOE is conducting a study to better characterize emissions from these types of wells (expected to be publicly available in early 2022). EO 13990 requires the Federal Government, “...be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.”

The commenters (1341-PGCC *et al.*) state that EPA’s justification for abruptly abandoning the model plant approach for determining whether low-producing well sites are exempt from LDAR requirements is flawed.

The commenters (1341-PGCC *et al.*) refer to sections of the preamble to the November 2021 Proposal discussing EPA’s prior use of model plants to estimate emissions across different well sites. The commenters say that notably, EPA’s historical model plant approach in developing new source performance standards for the oil and natural gas sector led to the low-production well site” exemption to LDAR requirements embodied in the 2020 Technical Rule. After years of using a low production model plant approach, EPA proposes to abruptly pivot to a site-level baseline methane emissions approach to determining whether a well site (even an extremely low-producing stripper well site) is subject to LDAR requirements, the commenters remark.

The commenters (1341-PGCC *et al.*) observe that a close look at EPA’s justification for abandoning the low-production well site approach shows it falls far short of a reasonable and fair analysis. EPA has failed to acknowledge, much less obtain and analyze, the pending final draft DOE study designed to provide a “robust, “apples-to-apples” assessment of methane emissions from marginal vs. non-marginal well sites. EPA also does not reference or analyze the OGI monitoring results from the Independent Oil and Gas Association of New York (IOGANY) study and the results of PADEP’s monitoring, both of which are explained in detail and provided with PGCC’s August 12, 2021, letter that was sent to EPA. Rather than review and evaluate a study

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<sup>258</sup>The following link shows the current status of the project: <https://netl.doe.gov/node/9373>.

performed by a sister Agency and other information provided to it, the commenters state that EPA's proposed pivot to a "site-level baseline methane emissions" approach appears to be based solely on data and information provided by an environmental group, without independently and objectively evaluating and analyzing that data. Further, the commenter says that EPA acknowledges that this data and information does not unequivocally prove that low-producing well sites emit more than other well sites, and instead, EPA states that it is "quite possible" that low-producing well sites "could have higher emissions."

The commenters (1341-PGCC *et al.*) do not believe EPA has provided adequate justification for moving away from the model plant approach. The commenters request that EPA release and consider the NETL's final draft report on methane emissions from marginal well sites and re-open its hasty decision to abandon the model plant approach for determining projected costs and emission reductions for potentially requiring LDAR at the extremely low-producing oil and gas wells. A meaningful and objective analysis of all available information will show that the small operations of members of the commenter's group should be exempt from any LDAR requirement in the November 2021 Proposal, both because the cost-effectiveness for any such requirements are prohibitive and because any emissions do not warrant potentially costly requirements.

Response I-7-94: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to establishing an equipment-based approach for determining the fugitive emissions monitoring and repair requirements.<sup>259</sup> Please also see section X.A.1.a.ii of the preamble to the final rule which details EPA's final standards related to the four subcategories of well sites, including single wellhead only well sites and small well sites.

Comment: Commenter (0814-IPAA *et al.*) states the predominant impact of EG OOOOc will be on low production well sites and their associated facilities. EPA has identified its view of low production well sites in the LDAR proposal as facilities emitting 3 tpy or less of methane. In other facilities, EPA has used different thresholds, such as 4 tpy of VOC for storage tanks or 6 tpy of VOC for storage tanks or 20 tpy of methane for storage tanks. These thresholds reflect various cost effectiveness assessments. Key to the analysis of emissions is the quality of emissions estimates – an issue where EPA's materials are suspect.

The commenter (0814-IPAA *et al.*) notes EPA's November 2021 Proposal to eliminate the low production well exemption and require all sources to calculate baseline emissions is extremely problematic for many small businesses and operators.

The commenter (0814-IPAA *et al.*) states EPA's continued emphasis on component counts over throughput and operating pressure in determining the amount of fugitive emissions fails to recognize basic physics. Almost all emissions calculations are based on throughput but to then discount throughput when evaluating fugitive emissions simply does not make sense. The Producer Associations are not disputing that component count does have an impact on emissions

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<sup>259</sup> 87 FR 74724-74736 (December 6, 2022).

– the more pieces of equipment connected together increases the chances for leaks – but the Producer Associations continue to argue that production rates and pressure play a significantly more important role in fugitive emissions.

The commenter (0814-IPAA *et al.*) notes the DOE Report has shown that most low production well sites (15 boe/d and less) emit less than 3 tpy of methane based on actual measurements. At issue is whether these measurement results would compare with the subpart W calculation in EPA proposal for the same facilities. The well site definition should be based on the common facilities at a well site that are not separately regulated under NSPS OOOO, OOOOa, or OOOOb. For example, tanks/tank batteries and liquid unloading operations should not be part of the well site emissions determination.

The commenter (0814-IPAA *et al.*) states while they believe that a low production well definition is a far simpler method that produces comparable results, on the basis of the above well site definition and the use of accurate emissions factors, the commenter notes that they can accept the concept of using a 3 tpy low production facility exclusion from the quarterly LDAR program but recommends an annual AVO (audio, visual, olfactory) review rather than the OGI EPA program.

The commenter (0814-IPAA *et al.*) states it is essential that EPA recognize that most of the well sites falling below 3 tpy will be operated by small businesses and small businesses that are unaccustomed to calculating methane emissions. Consequently, EPA needs to develop, in concert with the Small Business Administration, a straightforward guideline document that operators could use in determining whether a site is below 3 tpy of methane. This guideline document should be developed prior to the planned supplemental proposal for NSPS OOOOb and EG OOOOc and subject to comments during that proposal.

The commenter (0814-IPAA *et al.*) states to elaborate on this issue, while EPA lays out a conceptual approach to determine site emissions using available subpart W emissions factors and other estimating tools, small production operations have no familiarity with these tools and the subtleties of their application. If EPA continues to reverse its position on the use of production rates to define a threshold to recognize lower regulatory requirements, it should recognize that the DOE Report provides data showing that these well sites overwhelmingly fall below the 3 tpy of methane emissions based on actual sampling. Moreover, the framework that the DOE Report created in defining the factors that can influence emissions, *e.g.*, production rate, oil or natural gas production, number of pieces of equipment at the site, could provide EPA with a framework for the development of an emissions calculation guideline for small businesses and low production well sites.

Commenter (0585-KOGA) believes that the 2020 Technical Rule exemption for wells producing less than 15 barrels per day (or equivalent gas flow) was appropriate and easily understood by industry and regulating entities alike. If EPA is going to continue using an emission rate, the commenter recommends that EPA utilize the same emission rate as NSPS OOOO that sources emitting less than 4 tons per year are exempt from monitoring and reporting requirements. The sources do not produce enough of emissions to justify the high cost of monitoring and reporting requirements set forth by EPA.

Response I-7-95: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to establishing an equipment-based approach for determining the fugitive emissions monitoring and repair requirements.<sup>260</sup> The EPA is finalizing the equipment-based program using model plants each with various equipment types located at the site. In the final rule, well sites with specific leak-prone equipment have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment, e.g., small well sites) have a different set of requirements. Section X.A.1.a.ii of the preamble to the final rule details EPA's final standards related to four subcategories of well sites.

Comment: Commenter (0810-Petroleum Alliance-OK) states marginal wells are defined in federal law as oil wells producing 15 barrels per day or less and natural gas wells producing 90 thousand cubic feet (Mcf) per day or less. The Interstate Oil and Gas Compact Commission (IOGCC) defines a marginal well as a well that produces 10 barrels of oil or 60 Mcf of natural gas per day or less. However, according to the IOGCC's 2016 report regarding marginal wells in Oklahoma, the average crude oil and natural gas production for a marginal well is approximately 1.43 barrels per day of crude oil and 18 Mcf of natural gas per day. Oklahoma has approximately 28,000 marginal crude oil wells and 45,000 marginal natural gas wells. Approximately 9.5 percent of Oklahoma's total crude oil production and approximately 12.0 percent of Oklahoma's total natural gas production comes from marginal wells. These wells provide an important revenue resource for the State. In addition, small businesses in the Mining, Quarrying, and Oil and Gas Extraction industry in Oklahoma employ over 20,000 people, or over 50.5 percent of the private workforce employed in that sector in 2017. Many small oil and gas businesses may be negatively impacted if the November 2021 Proposal is implemented.

The commenter (0810-Petroleum Alliance-OK) adds that marginal wells provide a significant share of the U.S. domestic oil and natural gas output and economic contributions. The commenter states that since approximately 2006, marginal wells have produced oil and natural gas valued at nearly \$30 billion annually, or approximately 10 percent of the total value of oil and natural gas produced domestically. It is important that EPA understand the importance and benefits of marginal wells and small business impacts to the U.S., the State of Oklahoma, and small businesses, and consider this information in its rulemaking process.

Commenter (0824-WDEQ) adds that there would be significant costs associated with meeting the requirements of proposed Appendix K, which are entirely inhibitive for many stripper well operators who would be subject to these requirements. As such, the commenter disagrees with EPA's assessment that it "no longer believes that production levels provide an appropriate threshold for any exemption from fugitive monitoring." Small operators are already voicing concerns that they will have to shut down operations demonstrating that EPA's assessment is inaccurate, the commenter concludes.

Commenter (0929-National Stripper Well Association (NSWA)) states that an important reason that EPA should pursue the traditional process is that the DOE is poised to release a study – many weeks overdue – on emissions from low production wells that needs to be reviewed and

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<sup>260</sup> 87 FR 74724-74736 (December 6, 2022).

considered by EPA as it intends to withdraw certain exemptions for low production wells. The study will provide in depth analysis on methane emissions produced by marginal wells and the results of that study will be extremely valuable to this rulemaking process.

Commenter (0929-NSWA) states that this federally-funded report on the “Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells” will provide actionable data on how small production operations contribute to global emissions, and preliminary information from the DOE indicate no quantifiable or measurable emissions. With the report due to be released any day now, there is no justifiable reason to not wait so that the results can be fully considered as part of the rulemaking process prior to the DOE study being released to the public, fully analyzed by EPA, and incorporated into the agency’s decision making process on a final methane rule, which should also be subject to a 90 day comment period.

Commenter (0946-Michigan Oil and Gas Association (MOGA)) notes that during their Small Business Advocacy Review (SBAR) meetings, many small-entity oil and gas companies from all over the U.S. expressed their concerns regarding the expansion of NSPS OOOOa regulations to marginal and low production wells. The commenter did not receive an answer to whether EPA had evaluated the long-term environmental costs regarding early plugging of producing wells and the correlated ripple effect on the environment resulting from the drilling of new wells. The exploration, site preparation and drilling of new wells will likely be expedited as marginal and low production wells are forced to be plugged and abandoned early by burdensome regulations. The commenter states that the responsible long-term management of existing oil wells would offset the tremendous costs and environmental impacts related to drilling new wells to replace the lost oil production from already drilled and constructed wells and facilities. The commenter was unable to voice questions and concerns regarding proposed actions to include low and marginal wells into regulations originally designed for high volume production operations. These proposed actions would create conflicting regulations to the State of Michigan’s Natural Resources and Environmental Protection Act 451 of 1994, Section 324, Part 61504 law to prevent the waste of resources. The genesis of the State of Michigan’s regulations was to prevent over production of well early in a well’s lifespan, which can damage the producing formation and create isolated and un-recoverable pockets of oil and gas. Instead, Michigan’s regulations require operators to throttle production to enhance the longevity of production and protect against un-recoverable and wasted resources.

Response I-7-96: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to establishing an equipment-based approach for determining the fugitive emissions monitoring and repair requirements.<sup>261</sup> This approach does not require the owner/operator to calculate the site baseline emissions, but rather requires an identification of equipment located at the site in order to determine which of four subcategories the well site falls into. Section X.A.1.a.ii of the preamble to the final rule details

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<sup>261</sup> 87 FR 74724-74736 (December 6, 2022).

EPA's final standards related to the four subcategories of well sites, including the final requirements for small well sites.

Comment: Commenter (1341-PGCC *et al.*) suggests that the EPA consider the small, low-emitting nature of Pennsylvania and New York conventional oil and gas production before imposing any additional requirements in the NSPS OOOOa revisions, NSPS OOOOb and EG OOOOc. Commenter (0577-KIOGA) states that the potential for VOC and GHG emissions from an unconventional oil or gas well is proportionately higher than conventional oil or gas wells (and provides information on unconventional oil and gas well production to support their statement).

Commenter (1341-PGCC *et al.*) states that EPA's November 2021 Proposal generally takes a one-size-fits-all, industry-wide approach to determining whether additional, and potentially far more restrictive requirements, should be imposed on oil and gas producers. The commenter's members are comprised primarily of small, family-owned businesses and individuals operating low-producing oil and gas wells, as compared to the large, high-volume unconventional gas wells being drilled for several miles into deep geologic formations. These profound differences, in scale, production, design, and layout, must be accounted for by EPA, both in terms of understanding the adverse economic impact the November 2021 Proposal, if finalized, will have, and in terms of ascertaining whether EPA is justified in imposing requirements to regulate the small amounts of emissions from conventional oil and gas operations in Pennsylvania and New York.

Commenter (1341-PGCC *et al.*) points out that the emissions profiles associated with conventional operations are vastly different than those associated with unconventional operations. Almost all Pennsylvania and New York conventional wells are low producing "stripper" wells. By contrast, conventional well pads are 35 or more times smaller than unconventional well pads and, therefore, cause drastically less surface disturbance than unconventional pads. Significantly smaller amounts of supplies and equipment-including water and large trucks-are needed to conduct conventional operations than are required for the high-volume hydraulic fracturing performed at unconventional wells. Conventional producers generally use less than 10 percent of the pumping capacity as compared to an unconventional well, and wellhead pressures at conventional wells quickly decrease to very low pressures with many operating at less than 50 psi. New unconventional wellheads pressures are measured in the thousands of pounds. These differences in infrastructure and processes translate to small well pad emissions, and fugitive emissions are much lower at conventional wells given the extraordinarily low wellhead pressures.

Commenter (1341-PGCC *et al.*) states that the typical conventional oil well site in northwestern Pennsylvania and New York State would not normally include the following emission sources:

- Glycol dehydrators
- Amine gas sweetening units
- Line heater, heater treater, and reboilers
- Gas compressors (a gas compressor, when in use, would typically be associated with a group of wells, not a single well)
- Pneumatic controllers

- Pneumatic pumps
- Pipeline blowdowns

Commenter (1341-PGCC *et al.*) states that conventional natural gas wells in Pennsylvania and New York are similarly simple facilities. Typical conventional gas wells also involve many fewer fugitive equipment items (valves, connections, *etc.*).

Response I-7-97: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and small well sites.<sup>262</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to single wellhead only well sites and small well sites.

As discussed in the December 2022 Supplemental Proposal, large leaks can occur from single wellhead only well sites and small well sites. These emissions can be easily identified using AVO inspections alone and would not require the use of OGI. The EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. For small well sites, the EPA considered many factors in finalizing monitoring requirements for these sites that have fewer pieces of equipment, many of which are owned and operated by small businesses, and the EPA is finalizing quarterly AVO inspections for these sites.

Comment: Commenter (0810-Petroleum Alliance-OK) states EPA should allow operators the ability to reduce monitoring if fugitive emissions monitoring findings are reduced or eliminated, especially for marginal/low producing wells. For example, upon completion of two successful (no findings) OGI inspections, the inspection interval requirement should be reduced to one time per year or every 2 years. In addition, EPA should consider incentives that encourages operators to anticipate sources of emissions and/or install proactive measures to effectively monitor or manage those emissions.

Response I-7-98: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and small well sites.<sup>263</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to single wellhead only well sites and small well sites. Specifically, EPA is finalizing quarterly AVO inspections of fugitive emissions at single wellhead only well sites and small well sites. As discussed, EPA disagrees that low producing wells correlates with low emissions.<sup>264</sup> With respect to the commenter's request to reduce monitoring after not finding any fugitive emissions in two back-to-back monitoring surveys, EPA disagrees. EPA has previously considered the shifting monitoring frequency based on performance but found that a reduced monitoring schedule is inappropriate for a number of reasons, where one major reason is that this could result in fugitive emissions being undetected longer due to less frequent

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<sup>262</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>263</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>264</sup> 87 FR 74731 (December 6, 2022).

monitoring.<sup>265</sup> These same reasons apply under this rule and EPA is therefore finalizing a fixed-frequency monitoring.

#### **7.1.10 Small Business/Operators**

Comment: Commenter (1341-PGCC *et al.*) suggests that EPA has ignored or failed to address several key recommendations of the small entity representatives. Regarding fugitive emissions, the Panel Report<sup>266</sup> recommended that EPA “impose fewer requirements on sources that are less likely to emit methane and/or have demonstrated a history of insignificant emissions.”<sup>267</sup> To learn more about such sources and their emissions, the Panel Report recommended EPA solicit comment on regulatory alternatives for low production well sites and for “additional data, such as the DOE study, that assess the emissions from low production well sites and subsequently use this data to evaluate how monitoring requirements can be tailored to address sources mostly likely to be the sources of largest emissions and, if warranted, subcategorize sources unlikely to emit significant amounts of methane.”<sup>268</sup>

Response I-7-99: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and small well sites.<sup>269</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to single wellhead only well sites and small well sites. As discussed in that section, EPA evaluated data from the DOE Study, which EPA found does not show a correlation between production and the amount of fugitive emissions. However, analysis of the data indicated a strong correlation between the major equipment count and the frequency of fugitive emissions. For that reason, EPA proposed in 2022 to distinguish among well sites based on equipment and component counts. The EPA is maintaining this approach for the final rule and is finalizing quarterly AVO inspections of fugitive emissions at single wellhead only well sites and small well sites.

Comment: Commenter (0585-KOGA) states that many of their member companies are considered to be small entities who primarily operate low production wells, which requires a low-cost structure for profitable operation. The resources available to these companies are typically limited to the small staff that they can locally employ.

The commenter (0585-KOGA) appreciates EPA’s interest in the impact that the rules will have on small business entities and considering their perspective. As the commenter’s members read

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<sup>265</sup> 81 FR 35857 (June 3, 2016).

<sup>266</sup> Final Report of the Small Business Advocacy Review Panel on EPA’s Planned Rule Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector, Document ID No. EPA-HQ-OAR-20210317-0074 (Sept. 2021) (Panel Report).

<sup>267</sup> Id at 34.

<sup>268</sup> "DOE study" refers to the National Energy Technology Laboratory (NETL) study entitled "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells," Project No. DE-FE0031702. According to NETL's website, the "draft final report [from this study] was delivered to NETL on December 6, 2021 and is currently under review by DOE for release to the public." <https://netl.doe.gov/node/9373> (last visited Jan. 29, 2022).

<sup>269</sup> 87 FR 74724-74736 (December 6, 2022).



the preamble, there is little relief from the regulation for SERs. EPA has solicited input on a few topics throughout the preamble as they relate to small business; but has not identified any specific relief from compliance requirements for those companies that meet the SER definition. As EPA develops the final regulation, the commenter asks that EPA consider opportunities to address small business impacts and provide appropriate relief from sections of the regulation that will be overly burdensome for small business. The commenter suggests the following to provide relief:

- Reduce the proposed monitoring frequency to be no more than annually.
- Extended compliance period for SERs to be a year from the effective date.
- Permit AVO inspection for SERs.
- Provide a path to remove affected facilities from monitoring requirements when the emission rate falls below 4 tpy.
- Reduce the documentation requirements.

Response I-7-100: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and small well sites.<sup>270</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to single wellhead only well sites and small well sites.

As discussed in the December 2022 Supplemental Proposal, large leaks can occur from single wellhead only well sites and small well sites. These emissions can be easily identified using AVO inspections alone and would not require the use of OGI. The EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. For small well sites, the EPA considered many factors in finalizing monitoring requirements for these sites that have fewer pieces of equipment, many of which are owned and operated by small businesses, and the EPA is finalizing quarterly AVO inspections for these sites.

Comment: Commenters (0464-Muskegon Operating Company LLC (MOPC), 0824-WDEQ, 0938-TXOGA, 0946-MOGA) express concern on the impact the November 2021 Proposal with have on small operators and offer various suggestions for relief.

The commenter (0464-MOPC) argues that marginal wells are not a significant source of methane. Emissions from a well are proportionate to the volume of oil and/or gas produced. Marginal wells produce significantly less emissions due to the fact that they are marginal producers of oil and gas. Emissions from the commenter's wells are much lower than those emitted from high volume wells produced by larger companies. As a responsible operator, the commenter has taken action to voluntarily minimize their emissions in a prudent manner that meets standards they can afford.

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<sup>270</sup> 87 FR 74724-74736 (December 6, 2022).

The commenter (0464-MOPC) states that the economic viability of their company relies on efficient and low-cost operations. The commenter opposes the proposed regulations as they will have significant detrimental impacts on their operations, costs, overhead, reserve recovery, plugging costs, and employment. The regulations will unnecessarily, unreasonably, and disproportionately raise the company's operating costs. Every increase in cost directly jeopardizes the commenter's ability to produce marginal wells. The commenter's company will not be able to absorb the additional regulatory costs.

The commenter (0464-MOPC) believes it is unfair and unwise to treat small operators with marginal wells in the same manner as larger producers. Marginally producing wells must be exempt from EPA rules because the emissions are insignificant and the rules would be uneconomic. There must be a regulatory "off ramp" for wells that are low producers. The commenter supports the exemption of marginal, low production wells from the November 2021 Proposal.

The commenter (0938-TXOGA) appreciates that EPA is concerned about underestimating the burdens potentially imposed on homeowners, farmers, and small businesses by virtue of the fugitive emissions monitoring and other requirements contemplated under the November 2021 Proposal. The commenter requests that EPA consider and incorporate into any supplemental proposal or final rule the findings of the currently ongoing DOE study on marginal wells, even if the final report has not been issued in time for the next phase of this rulemaking.<sup>271</sup>

The commenter (0946-MOGA) suggests the EPA consider past small business's documented emission reductions as a factor in their required fugitive monitoring schedule. Once again, the EPA appears to be penalizing small businesses that have adhered to requirements outlined in the current NSPS OOOOa and previous NSPS OOOO rule. These small businesses feel "targeted" for their emission reduction efforts based on past regulations and now wonder if it will end? The commenter attended several meetings with the EPA during which, the EPA admitted the bulk of emissions come from a small group of sites and companies. For these reasons, the commenter believes the EPA should avoid penalizing small businesses with documented emission reduction efforts with an "Exemption Classification" for fugitive emission monitoring.

Response I-7-101: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and small well sites.<sup>272</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to single wellhead only well sites and small well sites.

The EPA disagrees with the commenter that marginal wells are not a significant source of methane. As discussed, EPA disagrees that low producing wells correlates with low

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<sup>271</sup> See National Energy Technology Laboratory, "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" (Project Number DE-FE0031702), <https://netl.doe.gov/node/9373> (stating that a draft final report of the study is currently under review by DOE for release to the public).

<sup>272</sup> 87 FR 74724-74736 (December 6, 2022).

emissions.<sup>273</sup> The EPA discussed in the December 2022 Supplemental Proposal, large leaks can occur from single wellhead only well sites and small well sites. These emissions can be easily identified using AVO inspections alone and would not require the use of OGI. The EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. For small well sites, the EPA considered many factors in finalizing monitoring requirements for these sites that have fewer pieces of equipment, many of which are owned and operated by small businesses, and the EPA is finalizing quarterly AVO inspections for these sites.

Comment: Commenter (0439-Paxton Resources, LLC (Paxton), 0822-TAEP) is concerned that OGI requirements place unique burdens on small businesses.

Commenter (0439-Paxton) believes that by going after large emitters EPA would be penalizing small businesses with no regard for the science of emissions in companies like the commenter's. The argument could be made that through existing regulations including NSPS OOOO and NSPS OOOOa, the commenter has been able to reduce methane emissions by 60 percent over 9 years. This trend will likely continue based on depletion and implementation of existing regulations on future wells, equipment and facilities. It is the commenter's opinion that the EPA should focus on large emitters rather than implementing a broad approach across varying regions that unjustly penalizes and discriminates against small businesses who are achieving success in reducing emissions by meeting the existing standards. The commenter attaches data taken directly from published Subpart W reporting on the EPA's website illustrating three Michigan companies' reductions over the last nine years averaging 45, 65, and 56 percent for CO<sub>2</sub>, methane and nitrous oxide, respectively. The commenter asks why the data for small businesses is not being considered.

The commenter (0822-TAEP) says that EPA has repeatedly heard in-house training and specialization on this is the best way to control cost, but that option is not always available to small businesses. The prospect for contract or outsourcing this requirement will place undue burden on small operators and cost estimates should reflect regional variability and rural workforce considerations that will show dramatic differences in price per service. The commenter surveyed their membership and suspect \$2,368 per facility to be low. Many of the comments from members reflect they lack the adequate staff and resources to meet this new requirement should it be implemented for all facilities. "This expense combined with other monitoring activities would make some of our leases uneconomic," said one member. Another said, "We have low volume wells. This would be cost prohibitive." For low production wells there is a significant concern that cost cannot be absorbed due to price constraints and the inability to absorb new operational requirements. This will result in a heightened negative impact to small businesses.

The commenter (0822-TAEP) asked if this contracted workforce was available across Texas to perform this new requirement and 74 percent of respondents said 'No'. There were a variety of reasons for this which included lack of workforce and training with many objections raised on the need for this at smaller operations or marginal production facilities. In many cases, operators reported that those cost may be higher because the internal operations to adapt and conduct new regulatory requirements has been limited due to the contraction of the industry in 2020. The

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<sup>273</sup> 87 FR 74731 (December 6, 2022).

commenter created and tracks a Texas upstream oil and gas economic index, and the employment data contained within indicates the loss of about 36 percent of direct upstream jobs in Texas in the 2019-2020 industry contraction. These limitations skew the cost estimate higher due to operators being more reliant on third-party contractors to facilitate revisions to emission controls not already required by state and federal law.

Response I-7-102: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to establishing an equipment-based approach for determining the fugitive emissions monitoring and repair requirements.<sup>274</sup> The EPA is finalizing the equipment-based program using model plants each with various equipment types located at the site. In the final rule, well sites with specific leak-prone equipment have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment, e.g., small well sites) have a different set of requirements. Section X.A.1.a.ii of the preamble to the final rule details EPA's final standards related to four subcategories of well sites.

The EPA disagrees with the commenter that marginal wells are not a significant source of methane. As discussed, EPA disagrees that low producing wells correlates with low emissions.<sup>275</sup> The EPA discussed in the December 2022 Supplemental Proposal, large leaks can occur from single wellhead only well sites and small well sites. These emissions can be easily identified using AVO inspections alone and would not require the use of OGI. AVO inspection is a low cost and simple method for identifying emissions. The EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. For small well sites, the EPA considered many factors in finalizing monitoring requirements for these sites that have fewer pieces of equipment, many of which are owned and operated by small businesses, and the EPA is finalizing quarterly AVO inspections for these sites.

Comment: Commenter (0573-KDHE) responds to EPA's solicitation of comment on fugitive emissions monitoring requirements burdens on small businesses. The commenter maintains an inventory of all oil and gas wells in the state, as well as annual oil and gas production by operator and cites various numbers in their comment letter indicating number of oil and natural gas operators and their 2020 production levels.<sup>276</sup> The commenter notes that numbers point to an unfair burden on small Kansas producers, and recommends alternative, less burdensome standards be proposed for small producers or that they be considered exempt from this rulemaking.

Response I-7-103: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to single wellhead only well sites and

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<sup>274</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>275</sup> 87 FR 74731 (December 6, 2022).

<sup>276</sup> 2020 production values by operator can be found at [www.kgs.ku.edu/PRS/petroDB.html](http://www.kgs.ku.edu/PRS/petroDB.html).

small well sites.<sup>277</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA's final standards related to single wellhead only well sites and small well sites.

As discussed in the December 2022 Supplemental Proposal, large leaks can occur from single wellhead only well sites and small well sites. These emissions can be easily identified using AVO inspections alone and would not require the use of OGI. The EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. For small well sites, the EPA considered many factors in finalizing monitoring requirements for these sites that have fewer pieces of equipment, many of which are owned and operated by small businesses, and the EPA is finalizing quarterly AVO inspections for these sites.

Comment: Commenter (0742-Alaska Department of Environmental Conservation (AK-DEC)) states the Oil and Natural Gas development is an important economic driver for the State of Alaska providing critical domestic energy production to the United States as well as local job opportunities, resources, and other benefits to Alaska and its citizens. Alaska exercises stringent regulatory authority by numerous State agencies, this Department, the Alaska Oil and Gas Conservation Commission (AOGCC), the Department of Natural Resources, and several others, but wants to emphasize that this proposed rulemaking could punish Alaska and its oil and gas industry for less stringent regulatory oversight in other states, such as Texas and North Dakota. As an example, venting and flaring is closely regulated and monitored in Alaska through the efforts of the department and AOGCC's oversight under state regulations. An article discussing Colorado methane monitoring also proposes that EPA's one-size-fits-all approach may not be appropriate.<sup>278</sup> The commenter is concerned that EPA appears to be headed toward an approach that may not fit well for all production basins leading to detrimental impacts on Alaska's oil and gas industry for limited gains in emission reductions.

Response I-7-104: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>279</sup> Please also see XI.A of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites, centralized production facilities, and compressor stations.

Comment: Commenter (0763-TCEQ/RRC) requests that a guidance document similar to the small business compliance guide for NSPS OOOOa be developed and provided as a tool to help companies understand the complex regulatory requirements that this NSPS will incorporate.

Response I-7-105: Small Entity Compliance Guides (SECGs) are prepared by EPA pursuant to section 212 of the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA) (Title II of Public Law 104-121). EPA prepares a SECG unless the agency can certify that the final rule will not have a significant economic impact on a substantial number of small entities. As discussed in section XVII.C of the final preamble, EPA discusses the Regulatory Flexibility

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<sup>277</sup> 87 FR 74722-74740 (December 6, 2022).

<sup>278</sup> Website at: <https://www.cpr.org/2021/11/01/colorado-oil-and-gas-methane-emissions-testing/>

<sup>279</sup> 87 FR 74724-74736 (December 6, 2022).

Act and EPA's initial and final regulatory flexibility analysis. The EPA will be preparing a SECG for NSPS OOOOb pursuant to SBREFA.

### ***7.1.12 Class II Water Disposal Wells***

Comment: Commenter (1085-SOS) states that under the rule, EPA provides an exemption for Class II water disposal wells. However, the rule has no discussion about Class II enhanced oil recovery (EOR) wells (a well that is also injecting produced water back into the ground, just into an oil-bearing-strata instead of a non-oil bearing strata for disposal). The commenter believes EPA should provide the same exemption for all Class II wells.

Response I-7-106: As currently defined in 40 CFR §144.6, EOR water injection wells are already included, specifically named under 40 CFR §144.6(b)(2):

(b) Class II. Wells which inject fluids:

(1) Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection.

(2) For enhanced recovery of oil or natural gas; and

(3) For storage of hydrocarbons which are liquid at standard temperature and pressure.

The EPA believes this resolves the commenter's concerns.

### ***7.1.13 Miscellaneous Others***

#### **7.1.13.1 Clarifications/Definitions/Units**

Comment: Commenters (0782-BHE, 0813-Black Hills Energy) request clarification on EPA's intent for production wells and underground storage wells.

Commenter (0782-BHE) argues the November 2021 Proposal does not clearly distinguish between production wells and underground storage wells, yet it appears that some requirements are intended to apply to wells in the production segment and not underground storage. The commenter recommends that EPA clearly define each well type. Further, if proposed "well" requirements are intended to include underground storage wells, then the commenter requests additional background to understand and address this requirement and opportunity to provide comment.

The commenter (0782-BHE) states the November 2021 Proposal material and context appear to indicate that LDAR requirements for compressor stations apply to wells located at underground storage facilities (*i.e.*, underground storage facility wells fall under "compressor station" rather than "well" related requirements), and that "well" requirements in the November 2021 Proposal

apply to the production segment but not storage wells. The commenter requests that this be clearly reflected in Supplemental Notice regulatory text. If EPA intends broader applicability for storage wells, then the commenter requests additional support for the rule in the TSD and RIA, because that analysis appears to focus on production wells. Justification for any new requirements for underground storage wells will allow industry to understand EPA's intent and provide feedback on technical feasibility more fully. The commenter requests EPA outreach to underground storage facility operators if new requirements are considered to ensure nomenclature, emission estimation methods, *etc.* associated with well emission estimates and categorization accurately reflect industry standards. This will also help eliminate additional confusion regarding differing requirements for production segment wells versus transmission and storage underground storage wells.

The commenter (0782-BHE) argues the lack of proposed regulatory text at times creates uncertainty around EPA's intent in the November 2021 Proposal. The transmission and storage segment includes underground storage facilities that include compression and storage wells. Regulatory text is needed to clarify what, if any, "well related" requirements discussed in the November 2021 Proposal apply to underground storage wells. The commenter suggests this could be clarified in the Supplemental Notice by including definitions for "underground natural gas storage wells" and production-related wells, and clearly indicating applicability for the different well types. For example, if a baseline emissions determination is intended to apply to transmission and storage wells, the commenter suggests emission estimates should consider segment specific characteristics and exclude non-regulated components from the emissions estimate. In addition, the commenter recommends excluding equipment co-located at the underground storage facility from the emission estimate. The commenter strongly recommends that EPA clearly state that the proposed well-related requirements are applicable to the production segment, but not the transmission and storage segment. If that is not the case, the commenter requests additional data gathering and analysis to support requirements for underground storage wells as well as opportunity to comment on such proposed applicability.

Commenter (0813-Black Hills Energy) states to date, wells (in geological formations) located in the natural gas transmission and storage segment, which are used to store natural gas, are not specifically defined in NSPS OOOO or NSPS OOOOa. NSPS OOOO defines a gas well or natural gas well as "...an onshore well drilled principally for production of natural gas." NSPS OOOOa defines a well as "...a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected." Both definitions only address natural gas wells which extract gas from the earth. Neither of these definitions address natural gas wells in the natural gas transmission and storage segment which serve as temporary holding places to store natural gas until it is needed to serve customer demand. The commenter requests gas natural storage wells be explicitly excluded from the definition of "well" in NSPS OOOOb and EG OOOOc to be consistent with the precedent set by NSPS OOOO and NSPS OOOOa.

Response I-7-107: As defined in §60.5430b of the December 2022 Supplemental Proposal, and consistent with 40 CFR part 60, subpart OOOOa,

“*Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at §60.5397b, a well site does not include:

- (1) UIC Class II oilfield disposal wells and disposal facilities;
- (2) UIC Class I oilfield disposal wells; and
- (3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.”

The final rule retains the definition of a well site as proposed. As specified in the definition of a well site in §60.5430b, the only scenarios where a well site would not be subject to the fugitive emissions standards would be if the well site met any of the criteria in (1) through (3) of the definition. Therefore, the case the commenter described would be subject to fugitive emission standards for well sites under NSPS OOOOb and EG OOOOc.

Comment: Commenter (0392-C.E. Harmon Oil, Inc. (Harmon)) requests that EPA define the emission production threshold that requires inspection, what sources count, and so forth. The commenter asks if this new rule is like past GHG reporting where the American Association of Petroleum Geologists used certain groupings of counties as geologic basins, which EPA then used for areas to report GHG. Or, is the EPA going to look at each lease individually (as to tank battery which serves a group of wells), the commenter asks. If the commenter is under threshold for reporting years ago for the GHG reporting, and has since sold many leases, the commenter asks if it still would be considered under threshold.

Response I-7-108: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to establishing specific monitoring requirements based on the type of equipment located at the well site.<sup>280</sup> Please also see section X.A.1 of the preamble to the final rule which details EPA’s final standards related to fugitive emissions at well sites and centralized production facilities. The monitoring requirements vary depending on whether the well site is a single wellhead only well site, small well site, multi-wellhead only well site, a well site with major production and processing equipment and, or a centralized production facility. The specific fugitive emissions requirements can be found in §60.5397b of the final rule.

Comment: Commenter (1133-Gunn Oil Company (Gunn)) asks for communication in standard oil field measurements. The commenter understands gas measurements in 1,000 MSCF. All of the commenter’s instruments measure this way. The commenter also knows that anything below 1 or 2 MSCF per day rates are too small to measure and unreliable, not to mention uneconomical to try and sell. The API or some other institution that has standards for measurements should get involved to decide what is acceptable standards for measurements. The commenter sees a lot

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<sup>280</sup> 87 FR 74736 (December 6, 2022).



about cameras and infrared images. While there is no doubt these can detect leaks, they cannot measure volumes accurately.

Response I-7-109: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for subcategorizing well sites in the December 2022 Supplemental Proposal. In the December 2022 Supplemental Proposal, the EPA proposed an equipment-based program using model plants each with various equipment types located at the site. The equipment-based approach requires identification of the specific equipment located at the well site in order to determine the specific fugitive emissions monitoring requirements that apply and does not involve quantification of emissions. The EPA is finalizing the equipment-based approach, and this should resolve the commenter's concerns regarding units of measurements.

Comment: Commenter (0817-GPA) notes that the November 2021 Proposal requires operators to "take corrective action to complete all necessary repairs" of control devices "as soon as practicable." The term "as soon as practicable" should be defined. Without some specific period in which to effect repairs, and the ability to delay repairs if needed, operators are deprived of the fair notice required to comply with the law. Otherwise, the question of whether an operator failed to repair a control device "as soon as practicable" will fall to EPA inspectors and enforcement personnel who will determine whether or not a violation occurred on an *ad hoc* basis. While the commenter appreciates the flexibility implied by an "as soon as practicable" standard, a set time period to effectuate repairs, such as 60 days for control devices, with the option to delay repair for necessity (e.g., avoiding shutdowns only for the repair, weather, unavailability of parts) has worked well for the LDAR program. If EPA is intent on (improperly) viewing control devices as leaking components, the commenter suggests adding a definitive time for repairs.

Response I-7-110: In the November 2021 Proposal, EPA proposed a definition of fugitive emissions components that included control devices with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit. However, based on comments received on the November 2021 Proposal, and additional information evaluated since 2021, EPA did not include control devices in the proposed definition of fugitive emissions components in the December 2022 Supplemental Proposal. With respect to control devices, the definition was finalized as proposed in the December 2022 Supplemental Proposal and EPA believes this resolves the commenter's concerns.

Comment: Commenter (0561-TRICORD Consulting, LLC (TRICORD)) requests clarification related to the definition of "repair." The definition currently states "Repair means that a component is adjusted, or otherwise altered, to eliminate a leak." The commenter asks for clarification whether "eliminate the leak" means no emissions (which the commenter believes is usually not possible) or if it means to eliminate the image of leakage using an acceptable camera and technique.

Response I-7-111: The December 2022 Supplemental Proposal regulatory text defined "repaired" in the context of fugitive emissions as follows:

§60.5430b(1): Repaired means the following:

(1) For the purposes of fugitive emissions components affected facilities, that fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in §60.5397b and resurveyed as specified in §60.5397b(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition.

This definition has been retained in the final rule. According to the definition, fugitive emissions are considered eliminated when the resurvey indicates fugitive emissions are below the applicable fugitive emissions definition. This means that if EPA Method 21 is used to resurvey, the fugitive emissions component is considered repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppmv above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 of appendix A-7 of this part are used. If the resurvey is conducted using OGI, the fugitive emissions component is considered repaired when the OGI instrument shows no indication of visible emissions.

Comment: Commenter (0807-BP) states EPA should clarify regulatory text indicating follow up actions within 14 days of “receiving the data” from the alternative screening survey. As proposed, operators have to perform the “follow-up OGI survey of all fugitive emissions components at the site within 14 days of the screening survey.” In the supplemental rule, EPA should clarify that the 14-day window for a follow-up OGI survey commences upon the operator’s receipt of the advanced screening survey results from the vendor. There are situations where operators may not receive the final survey data from third-party vendors on the day of inspection. Should the language remain as written, delays in data receipt could unintentionally consume several days afforded in the 14-day window for follow-up OGI surveys. In so doing, operators would end up with less time to execute follow-up surveys. Assuming the intent is to provide operators with a full 14 days to perform the follow-up surveys, EPA should clarify that this window begins at the time of data receipt, not the survey itself.

Response I-7-112: In the December 2022 Supplemental Proposal, EPA proposed specific frequencies for conducting periodic screenings based on the minimum detection threshold of the screening technology in the approved alternative test method(s) selected to conduct the periodic screenings. This included when regular OGI follow-up surveys would be required. Following a periodic screening, EPA proposed that the owner/operator must receive the results of the periodic screening no later than 5 calendar days after the screening occurs. The EPA is finalizing this requirement. If the results of the periodic screening indicate a confirmed detection of emissions from an affected facility, a monitoring survey of the entire fugitive emissions components affected facility must be conducted and all sources of fugitive emissions must be repaired and confirmed repaired within 30 days of receiving the results of the periodic screening. There is no specific timeframe to conduct the follow-up OGI survey or start the repairs, as long as the repairs are completed and confirmed within 30 days of receiving the results of the screening.

Comment: Commenters (0425-Darrah, 1085-SOS, 1101-Triple T Oil, LLC (Triple T)) state wells are already monitored and audited on barrel in the case of oil and thousand cubic feet (MCF) in the case of gas volumes by regulatory agencies. Changing 3 tpy to a BBL or MCF equivalent per day would provide ease of implementation and easier understanding for small producers.

The commenters (1101-Triple T, 1103-Town Oil Company (TOC)) state Eastern Kansas wells are very low-producing wells and there are many of them. There needs to be a clear definition of the amount of emissions being produced per bbl of oil that requires inspection. There also needs to be a clear definition of the source from which it is coming from, *i.e.*, well or tank battery. The regulation is extremely unclear the way it is written. The commenter (1103-TOC) adds it will be extremely expensive for a small lease owner to be able to afford the monitoring system. This more than likely will shut down production and the commenter will have to plug the wells.

Response I-7-113: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for subcategorizing well sites in the December 2022 Supplemental Proposal. In the December 2022 Supplemental Proposal, the EPA proposed an equipment-based program using model plants each with various equipment types located at the site. The equipment-based approach requires identification of the specific equipment located at the well site in order to determine the specific fugitive emissions monitoring requirements that apply and does not involve quantification of emissions. The EPA is finalizing the equipment-based approach, and this should resolve the commenter's concerns regarding units of measurements. In addition, the equipment-based monitoring approach that EPA is finalizing makes it clear which monitoring requirements apply to each type of site (*i.e.*, single wellhead only well site, small well site, multi-wellhead only well site, well site with major production or processing equipment, or centralized production facility).

Comment: Commenter (0938-TXOGA) states inclusion of equipment such as natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines in the definition of "major production and processing equipment" would unnecessarily expand the scope of the regulation to include a number of small sources that are not currently regulated and that do not have sufficient component counts to be considered a "well site" under any reasonable understanding of the term. Such an approach is not justified in light of the costs imposed on small operators with low emissions. The commenter notes that this approach would also be inconsistent with Subpart W, under which smaller equipment such as pumpjacks and pneumatic controllers would not be considered major production equipment.

Response I-7-114: In the November 2021 Proposal, EPA solicited comment on whether to expand the definition of major production and processing equipment to include natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines.<sup>281</sup>

In the December 2022 Supplemental Proposal, based on information evaluated following the November 2021 Proposal, EPA determined that it was not appropriate to keep natural gas-driven pneumatic controllers or natural gas driven pneumatic pumps as fugitive emissions components. The EPA stated that these devices are both separate affected facilities with separate standards. identified as BSER. Therefore, in the December 2022 Supplemental Proposal, EPA proposed to maintain the definition of major production and processing equipment as follows:

*"Major production and processing equipment means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels*

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<sup>281</sup> 86 FR 63173 (November 15, 2021).

collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.”

The EPA is maintaining this definition in the final rule, which does not include natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, or pumpjack engines.

Further, the EPA is finalizing the definition of a small well site, as proposed in the December 2022 Supplemental Proposal.

*Small well site* means, for purposes of the fugitive emissions standards in §§60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, or natural gas-driven pneumatic controllers.

#### 7.1.13.2 Extreme Weather

Comment: Commenter (0539-Alaska Oil and Gas Conservation Commission (AOGCC)) indicates that a first attempt at repair within 30 days of finding fugitive emissions and final repairs within 30 days of first attempt is not always feasible in Alaska for a couple reasons. First, there are several fields that have equipment that is literally not used anywhere else in the world so obtaining parts for a repair could be a lengthy process. Second, often times if an issue is discovered in the winter a temporary fix is completed as soon as practical but a permanent fix could require a full facility shutdown and due to the complexity of freeze protecting a facility in the winter time those shutdowns are usually performed in the summer time, so there are large chunks of the year where it would be incredibly difficult to complete a final repair within 30 days of the initial attempt at repair.

Response I-7-115: EPA has previously acknowledged the technical infeasibility issues with weather conditions for well sites and compressor stations located on the Alaska North Slope.<sup>282</sup> Consequently, reduced fugitive emissions monitoring was proposed in December 2022 at 60.5397b(g)(1)(v), which specified annual OGI monitoring for fugitive emissions monitoring of affected facilities on the Alaska North Slope. EPA disagrees that additional time is needed for sources in Alaska to conduct initial and final repair of fugitive emissions and EPA is finalizing the requirement of first attempt at repair within 30 days of finding fugitive emissions and final repair within 30 days of first attempt must be completed.

Comment: Commenters (0786-Enerplus, 0911-NDPC) note that unique weather conditions in North Dakota necessitate special provisions in locations with adverse weather conditions.

The commenter (0786-Enerplus) states increasing the frequency of LDAR inspections reduces the window of opportunity a company has to reschedule inspections delayed by adverse and dangerous weather conditions. North Dakota is one of the coldest states in the U.S. and weather can cause safety and logistical challenges. If a quarterly inspection frequency is upheld in the

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<sup>282</sup> 86 FR 63163 (November 15, 2021).

final rule, the commenter requests allowance for inspection delays due to adverse and dangerous weather conditions.

The commenter (0911-NDPC) states North Dakota's climate poses many safety and logistical challenges that can limit inspector access to oil and gas locations for days or weeks. Ice, snow, frigid temperatures, and high winds are common occurrences. North Dakota is the coldest state in the continental U.S. during the winter and fall<sup>283</sup>, and this year has already seen temperatures below -25 °F and wind speeds greater than 30 mph. Increasing the frequency of LDAR inspections reduces the window of opportunity a company has to reschedule inspections delayed by bad weather conditions. Also, some activities at well sites may increase the safety risk to the LDAR inspector. These activities include but are not limited to well completion, maintenance, and construction activities.

Response I-7-116: The EPA is allowing in the final rule an exemption of quarterly monitoring during extreme temperatures. The final rule at §60.5397b(g)(4) specifies that fugitive emissions components affected facilities quarterly monitoring requirements are waived during a quarterly monitoring period if the affected facility is located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period.

#### 7.1.13.3 Worker Shortages

Comment: Commenter (0733-Conservation Voters New Mexico (CVNM)) is concerned with the extensive requirements of the November 2021 Proposal and ask the EPA to consider worker shortages, costs, extreme weather conditions, and the highly specialized nature of the instrumentation. According to the commenter, New Mexico had ten inspectors for more than 52,000 operational wells in the state at the end of 2020, and one inspector indicated at that time that she endeavored to "hit" every well at least once every three years. By contrast, the November 2021 Proposal requires that wells are to be monitored quarterly, semiannually, or annually.

Response I-7-117: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>284</sup> Please also see section X.A of the preamble to the final rule which details EPA's final standards related to monitoring requirements for fugitive emissions components from well sites.

#### ***7.1.14 EG 0000c***

Comment: The commenter (0739-Citation) states if existing sites are added to LDAR survey requirements as included in the November 2021 Proposal, the number of surveys will be extremely difficult to accomplish given the potential shortage of third-party LDAR contractors, which will be in high demand throughout the industry, and the remote locations of many of these

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<sup>283</sup> Website at: [www.worldatlas.com](http://www.worldatlas.com).

<sup>284</sup> 87 FR 74724-74736 (December 6, 2022).

sites. Alternate in-house options would also be difficult based on resulting high demand for OGI cameras and associated availability. The commenter requests that the fugitive provision for existing sites be eliminated or significantly reduced.

Response I-7-118: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>285</sup> Specifically, single wellhead only well sites and small well sites would be subject to quarterly AVO inspections only. Please also see section X.A of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites. The EPA expects that requiring AVO inspections only for single wellhead only well sites and small well sites will lessen the demand on OGI contractors overall. In addition, for the December 2022 Supplemental Proposal, the EPA evaluated whether to revise the November 2021 proposed two-year final compliance deadline. The EPA considered several factors that could impact the ability of a designated facility to come into compliance with the presumptive standards. The EPA described these factors in Table 31 of the 2022 Supplemental Proposal preamble.<sup>286</sup> One of those factors evaluated included the availability of specialized services (e.g., OGI contractors), which EPA acknowledged could have an impact on small businesses as the assumption is that contractors could prioritize larger businesses. The EPA also acknowledged here are a large number of designated facilities where owners or operators are dependent on the availability of equipment and services.

Comment: The commenter (0585-KOGA) believes that many marginal wells will be prematurely plugged because they will be subject to NSPS OOOOc. The wells will be covered by NSPS OOOOc because of EPA's definition of major production and processing equipment. Typical wellsite production equipment like gas/water separators, drip tanks, and water tanks (often less than 1,000 gallons in size) associated with low pressure gas wells do not have a significant potential for fugitive emissions, primarily because of the low pressures at which they are operated. But these low-pressure gas wells will require a monitoring program estimated by EPA to have an annual cost of \$4,200, 18.6 percent of the gross revenues (assuming the well produces 20 Mcf/day). The average gas well in Kentucky produces 6 Mcf/day. Using EPA's numbers, the compliance cost for the average well in Kentucky will be 62 percent of the gross revenue.

Response I-7-119: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to fugitive emissions from well sites.<sup>287</sup> Specifically, single wellhead only well sites and small well sites would be subject to quarterly AVO inspections only. Please also see section X.A of the preamble to the final rule which details EPA's final standards related to fugitive emissions from well sites.

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<sup>285</sup> 87 FR 74724-74736 (December 6, 2022).

<sup>286</sup> 87 FR 74835 (December 6, 2022).

<sup>287</sup> 87 FR 74724-74736 (December 6, 2022).

Comment: Commenter (0738-Exxon Mobil Corporation (Exxon)) urges EPA to consider whether flexibilities on use of new technologies could be leveraged to address methane emissions from existing sources immediately, rather than waiting years for the State Implementation Plan process to run its course. This could perhaps be accomplished through flexibility in the base program or how new AMEL applications are reviewed. For example, detecting and addressing emissions from existing sources could perhaps factor into how EPA determines whether an AMEL application achieves “at least equivalent” emission reductions, especially under the principle of focusing efforts on finding the largest leaks.

Commenter (1382-National Grid) supports EPA’s new requirements for states to develop plans to reduce emissions from existing sources, taking into account the safety and reliability of existing operations. To avoid potential redundancies and encourage compliance, the commenter recommends collaborating with stakeholders to review the best practices of current programs and allow states the flexibility to utilize emissions data collected through emerging technologies and strategies.

Response I-7-120: EPA agrees with the commenter that it is reasonable to consider allowing for flexibilities in the use of new and alternative technologies for methane detection. In the December 2022 Supplemental Proposal, EPA included specific provisions for the use of alternative test methods using advanced methane detection technologies that would allow for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and CVS used to route emissions to control devices. The EPA is finalizing these proposed alternatives that would allow for advanced screening technologies, which could be used to identify sooner than traditional detection methods such as OGI monitoring for fugitive emissions, covers on storage vessels, and CVS.

The final rule establishes a clear and streamlined pathway for technology developers and other entities to seek the EPA’s approval for the use of advanced measurement technologies under this alternative screening option. Under this pathway, entities would seek approval for alternative test methods to demonstrate the performance of alternative technologies, which would replace the use of OGI and AVO.

#### 7.1.14.1 Site-Specific Factors (Useful Life)

Comment: Commenter (1267-CA AG *et al.*) notes EPA is seeking comment on observations, any other facts that are unique to the oil and natural gas industry that could impact the remaining useful life and other factors demonstration, and whether the agency should include specific provisions regarding consideration of site-specific factors that would supplement or supersede those listed in EPA’s implementing regulations.

Commenter (1267-CA AG *et al.*) generally agrees with EPA’s observation that the design of the presumptive standards likely lessens the instances in which a performance standard in a state plan would need to be relaxed compared to the guideline to account for a facility’s remaining useful life or other site-specific factors. The control of fugitive emissions from well sites and compressor stations through use of LDAR, for example, could be done throughout the remaining useful life of these sources without the need to install any retrofit technology. In light of the fact

that CAA section 111(d)(1) requires that states be allowed to consider remaining useful life and other site-specific factors, however, the agency's observation is more relevant to the subsequent state plan process (specifically, EPA's evaluation of whether a state has demonstrated a variance for particular sources is warranted) as opposed to whether states can depart at all from EPA presumptive standards.

In the final emission guidelines, the commenter (1267-CA AG *et al.*) suggests that EPA provide guidance on how the remaining useful life criterion should be applied to the different types of designated facilities. The agency could include information on the anticipated design life of oil and natural gas wells, storage vessels, compressors, pneumatic controllers, *etc.* based on industry experience. States could then use that information in evaluating whether the remaining useful life of particular sources would justify a different numerical or non-numerical standard.

Response I-7-121: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.b of the December 2022 Supplemental Proposal related to OOOOc for fugitive emissions from well sites and section IV.A.2.b for compressor stations.<sup>288</sup> In the December 2022 Supplemental Proposal, the EPA also proposed and solicited comment on requirements for Remaining Useful Life and Other Factors (RULOF).<sup>289</sup> Please see section XIII.C.3 of the preamble to the final rule with a discussion of the requirements that EPA is finalizing as it relates to RULOF.

#### 7.1.14.2 Delay of Repair/Availability of Parts

Comment: Commenter (1391-Interstate Natural Gas Association of America (INGAA)) believes that after all of the necessary replacement parts are received, the appropriate amount of time needed to make a repair depends on whether a shutdown or blowdown is needed. If a shutdown or blowdown is needed, then NSPS OOOOc should provide that the repair may be delayed until the next scheduled shutdown for maintenance, not to exceed two years from leak discovery, as is allowed under NSPS OOOOa. This approach would also be consistent with EPA's approach to natural gas processing plants. There, EPA acknowledged the importance of making repairs during planned shutdowns and when parts are available.<sup>290</sup> This requirement was rational and safe for natural gas processing plants, and EPA should adopt a similar approach in NSPS OOOOc.

The commenter (1391-INGAA) suggests that where a shutdown or a blowdown is not needed to make the repair, then at least 30 days from receipt of all of the parts is needed to make the repair. This amount of time is needed to ensure operators have adequate time to develop a plan that ensures safety, minimizes system disruptions, and manages the necessary logistics. The commenter provides a list of requirements to ensure the safe installation of replacement parts in their comment. Some requirements include a pre-job safety analyses and accounting for extreme weather.

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<sup>288</sup> 87 FR 74737-74740 (December 6, 2022).

<sup>289</sup> 87 FR 74816 (December 6, 2022).

<sup>290</sup> See 48 Fed. Reg. 279, 289-90 (Jan. 4, 1983); 40 C.F.R. § 60.481a; 40 C.F.R. §§ 60.481a, 60.5430.



The commenter (1391-INGAA) recommends that regarding delay of repair, an identical approach to an amendment to NSPS OOOOa be followed due to availability of parts in NSPS OOOOc. EPA is proposing to amend NSPS OOOOa to allow repairs in the transmission and storage segments that require a shut down or blowdown to be delayed until the next scheduled shutdown for maintenance, not to exceed two years from discovery of the leak. In situations when the repair in question would require a shut down or blowdown, instead of adhering exclusively to a “30-day from date of receipt” repair requirement for delays based on acquisition of replacement parts, EPA should allow for such repairs to be made during the next scheduled shutdown for maintenance, not to exceed two years from discovery of the leak. Such an approach has the benefit of avoiding unnecessary blowdown emissions.

Similarly, commenter (0815-American Gas Association (AGA)) requests that EPA allow for lead times needed to obtain certain types of parts. The commenter states that operators should not be penalized for circumstances they do not control, and imposing penalties will not reduce emissions where a repair simply cannot be performed until a part is received. The commenter requests that EPA provide in the regulatory text for revised NSPS OOOOa and new EG OOOOc that where no shutdown or blowdown is needed, the operator should repair the leak within 30 days after receiving the parts. The commenter also requests that where a repair requires a shut down or blowdown, the regulatory text should allow the repair to be performed during the next scheduled shutdown for maintenance after receipt of the requisite parts, not to exceed two years. Again, according to the commenter, this will avoid unnecessary blowdown emissions.

Commenter (1391-INGAA) suggests that limiting the availability of the delay of repair for replacement parts will not have a beneficial effect. The delay envisioned by this provision would be to account for the *unavailability* of the means by which to make a repair in the allotted timeframe. It is not intended to alleviate a burden, create efficiencies, or manage challenging logistics, all of which are themselves appropriate reasons for providing delay of repair relief.

The commenter (1391-INGAA) states that the purpose of the replacement part delay of repair provision is to ensure that companies are not penalized for circumstances they cannot control or alter. Indeed, a rule that would impose such consequences is arguably arbitrary and contrary to EPA’s authority. Including the replacement part delay of repair provision would therefore strengthen any final EPA rule. Accordingly, because a limit on the replacement part delay of repair provision, even one based on the severity of the leak, would do nothing to speed the repair or change the availability of the necessary replacement part, such limits are not appropriate or useful.

Response I-7-122: In response to these comments, and consistent with the delay of repair provisions related to equipment leaks from equipment located at onshore natural gas processing plants, as well as amendments to NSPS OOOOa that the EPA is finalizing at 40 CFR 60.5397a(h)(3), the final rule for NSPS OOOOb and NSPS OOOOc includes delay of repair provisions based on the unavailability of parts. As described by the commenter, and in previous comments on amendments to NSPS OOOOa, there are exceptional circumstances that do occur where the repair cannot be completed successfully without replacement of a part that requires custom fabrication. In the previous response to this request for the 2020 Technical Rule, the EPA stated our belief that lack of availability of parts was not sufficient justification to allow for

delayed repairs, however, the exceptional circumstances referenced by commenters and the supply chain delays experienced as a result of the pandemic have highlighted that a delay of repair may be needed for rare circumstances beyond an owner or operator's control.<sup>291</sup>

## **7.2 Alternative Screening Using Advanced Measurement Technology**

### ***7.2.1 General Comments and Support***

Comment: Several commenters (0391-KBIC, 0401-Mercy, 0434-Impax, 0435-Wespath, 0437-NYOSC, 0458-Maryland Department of the Environment (MDE), 0558-Center for Climate and Energy Solutions (C2ES), 0570-Konica, 0579-Chevron, 0592-Citizens United for Responsible Energy Development (CURED), 0610-Occidental (Oxy), 0756-Baker Hughes, 0766-Cheniere, 0770-NPRC, 0777-Ascent, 0782-BHE, 0787-Atmos Energy Corporation (Atmos), 0807-BP, 0808-API, 0820-Pioneer, 0831-AXPC, 0832-New Mexico Environmental Department (NMED), 0844-EDF *et al.*, 0926-Austin Energy *et al.*, 0932-GHGSat, Inc., 0915/1290-Bridger Photonics, 0940-Responsible Drilling Alliance (RDA), 1372-Generate Capital, 1382-National Grid) are strongly supportive of EPA's consideration to include advanced technology alternatives.

Commenter (0437-NYOSC) notes that several investors call for support for the development and deployment of innovative technologies for methane emission mitigation.

Commenter (0782-BHE) recommends that EPA initiate a program to support technology and leak mitigation program development and standardization, rather than simply adopt new approaches. The commenter recommends that EPA could address the challenges related to ensuring data integrity from leak detection and mitigation programs during the program development, such as standard methods and equivalency definitions for measurement and monitoring technologies; and standard practices and procedures (*e.g.*, training, certification) for implementation.

Commenter (0782) requests that EPA clarify how precedent established by the proposed Appendix K would relate to community-based monitoring and emerging sensor technologies. The commenter states that EPA should state how the level of rigor required by Appendix K will be reconciled against stated objectives in the proposed rule identifying and promoting advancements in leak detection including remote sensing, sensor networks, satellite measurements, methane sensors, truck based, continuous, aerial technologies and other alternatives to Method 21. The commenter recommends that EPA should apply equal rigor for all applications, however, the commenter warned the proposed Appendix K may establish an onerous precedent. The commenter urges that EPA should explicitly discuss a strategy for assessing accuracy, developing methods, and establishing rigor for future leak detection technologies and applications, such as stakeholder or community monitoring using advanced sensor technologies.

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<sup>291</sup> See *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration*, 40 CFR Part 60, subpart OOOOa, *Response to Public Comments on Proposed Rule* [83 FR 52056, October 15, 2018]. pgs. 8199-8200.

Commenter (0807-BP) voluntarily deploys advanced monitoring programs that monitor all operated assets. Given their deployment of multiple detection technologies, operators are able to survey the commenter's assets more frequently, and in some instances at a lower cost per wellsite than LDAR programs. For example, by leveraging these different technologies at varying frequencies, operators are able to inspect all the commenter's U.S. onshore operated assets quarterly and more frequently inspect an increasing percentage of their entire U.S. onshore portfolio.

Commenter (0592-CURED) urges the EPA to permit and even facilitate experimentation with new technologies so their development will be accelerated. Regarding leak detection for example, larger producers (such as Jonah Energy) can afford to pilot continuous monitoring that ultimately can reach better emission controls, and they should be incentivized to do so, not discouraged by overly prescriptive requirements. Smaller companies may still need to be required to have minimum monitoring.

Commenter (0820-Pioneer) believes that EPA should explicitly allow in this rulemaking for alternative means of compliance, which can also be conceptualized as alternative work-practice standards, rather than relegating all such issues to the AMEL process under CAA section 111(h)(3). If EPA allows these technologies to be used, operators will be able to identify and correct issues well before periodic site-by-site surveys may find them -resulting in significant emission reductions. The only current avenue in the CAA for operators and/or manufacturers or vendors to seek approval to use an alternative technology is in EPA's AMEL process in section 111(h) of the CAA. Although significantly improved upon in the 2020 Technical Rule, the process has historically been ambiguous and complicated with no alternative certifications being granted thus far. Therefore, the commenter suggests having a means by which to use an alternative technology outside of the statutory AMEL process, will be extremely helpful and allow operators to capitalize on these technologies to reduce emissions at competitive costs.

Commenter (0831-AXPC) believes that there is sufficient evidence to show that several screening and monitoring technologies on the market today are capable of detecting fugitive emissions from affected sources as well as, if not better than, periodic surveys using OGI or EPA Method 21. Further, some technologies have been shown to detect certain types of emissions that OGI has missed, particularly in field deployment comparisons and across larger areas.

Commenter (0832-NMED) believes EPA should consider allowing technologies that provide quantifiable, verifiable, and consistent monitoring and compliance data at a scale that can accommodate large remote regional areas consisting of hundreds or even thousands of facilities.

Commenter (0926-Austin Energy *et al.*) states companies throughout the natural gas supply chain are gaining experience with advanced methane detection technologies. The commenter recognizes the potential value many of these technologies could provide and supports EPA's efforts in the November 2021 Proposal to recognize innovative alternative methane detection technologies that are demonstrated to be as effective as existing approaches. Through compliance with the existing federal methane regulation, the industry has demonstrated that it can reduce methane emissions at a reasonable cost using available technologies and strategies.

Commenter (0458-MDE) notes that Maryland's recent regulations for controls in the natural gas sector, final effective on November 16, 2020, can provide a basis for their suggested improvements to the November 2021 Proposal. The commenter supports innovative advanced technologies to discover fugitive emissions, and Maryland regulations allow for an alternative LDAR approval, however, none of the four companies operating in Maryland have requested this alternative and meet their LDAR requirements with the use of OGI and supplemental EPA Method 21.

Commenter (0940-RDA) supports the alternative screening program and specifically requests that EPA consider the following:

- Determine the actual benefits, not simply the hypothetical benefits, of OGI, and acknowledge its limitations.
- Use rigorous benefit-cost analysis to fairly compare alternative screening methods to OGI.
- Reduce the rigidity of EPA regulations that currently inhibit the introduction of new technology into the realm of methane emission detection.
- Use the teachings of increasing abundant literature on aerial surveillance of oil and gas facilities to further tighten limits on permitted vents.

Commenter (1372-Generate Capital) suggests that the regulation ensures that emissions reporting is independently carried out and verified by third parties; and ensures that emerging technologies including aerial surveys, continuous monitoring, and satellite imaging are acknowledged as viable technologies to measure fugitive methane emissions as soon as they achieve EPA data quality thresholds. The commenter recommends EPA consider creating a task force made up of leading companies in the sector as well as monitoring technology innovators, leading academics, and other experts from civil society to identify where further improvements in technology deployment and regulation can be made. Such a task force could also facilitate the sharing of best practices such that the level of ambition can be raised continuously over time as cost-effectively as possible.

Response I-7-123: EPA acknowledges the commenters support for the use of alternative technologies.

Comment: Commenters (0756-Baker Hughes, 0811-ABB Inc. (ABB)) argue alternative technologies should be the fugitive monitoring standard above OGI and EPA Method 21 techniques.

Commenter (0811-ABB) argues the November 2021 Proposal's reliance (or emphasis) on OGI as the technology 'standard' limits the rule's overall effectiveness. OGI indirectly detects methane, in this case, through air temperature changes perceived at a specific wavelength of light. The resulting images may be dramatic for large, leaks emanating from small holes or from rapidly propagating gas plumes. Unfortunately, OGI signals can be confounded by nearby structures at temperatures different from ambient air, local weather, sunlight, or if the source is underground. Even large plumes, if moving slowly, will not be detected by OGI and since OGI is over 100 times less sensitive than current laser-based methods, OGI will miss many leaks that

otherwise would be detected. Moreover, as documented by Methane Emissions Technology Evaluation Center (METEC) scientists, reliable OGI measurements require expert training. Basing the rule on OGI is problematic both as it is used to determine which obligations apply to designated facilities as well as the supplemental technology to be used annually to ensure that smaller leaks are detected.

Response I-7-124: EPA cannot base the BSER on advanced methane detection technologies, as no such technologies have yet been approved for use by EPA.

EPA acknowledges the commenters concerns on the limitations of OGI and notes that all technologies are subject to certain limitations. OGI camera operators can have difficulty finding leaks if they do not use proper survey technique. As long as OGI camera operators are properly trained and use adequate survey techniques, which include dwelling on equipment for an appropriate amount of time, ensuring appropriate thermal backgrounds, looking at equipment from multiple angles, and accounting for interferences, EPA has no reason to believe that the operator will not find fugitive emissions that exist.

EPA has sought to propose a reasonable pathway to allow for the use of technology other than OGI for the fugitive program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies<sup>292</sup>. Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (0811-ABB) adds that advanced technology records measurements at a specific physical point. This allows minimally trained surveyors to detect and pinpoint leaks quickly, efficiently, and without the margin of error of other technologies. This saves companies time and cost and reduces the complexity inherent in the use of costly and delicate OGI cameras.

Response I-7-125: EPA acknowledges the commenters support for the use of alternative technologies. EPA has taken this comment into account as they designed the alternative technology program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies<sup>293</sup>. Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

### ***7.2.2 Advanced Technologies***

Comment: Commenter (0844-EDF *et al.*) states a broad range of advanced methane monitoring technologies are available and can be utilized by operators to detect, pinpoint, and quantify fugitive emissions.<sup>294</sup> Over the past decade, rapid innovation has led to a diverse array of advanced methods: there are now at least 100 distinct methane measurement technologies that

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<sup>292</sup> 87 FR 74740-74744 (December 6, 2022).

<sup>293</sup> 87 FR 74740-74744 (December 6, 2022).

<sup>294</sup> *Id.*

are commercially available for leak monitoring in the oil and gas industry.<sup>295</sup> Detection capabilities vary greatly and typically increase with proximity to the emission source. However, technologies that monitor from farther away, like aircraft and satellites, are usually much faster and can cover broad geographic areas frequently.<sup>296</sup>

The commenter (0844-EDF *et al.*) states a comprehensive monitoring program that utilizes both screening and close-range technologies is likely to be highly effective.<sup>297</sup> In this type of program, screening technologies are used to monitor across broad geographic areas frequently to quickly detect the largest emission sources. Close-range methods are used for both directed follow-up to pinpoint emission sources detected during screening and to routinely monitor sites for smaller leaks that would not be detected by screening methods. Typically, screening surveys cannot identify leaks at the component level nor distinguish permissible, vented emissions from fugitive and abnormal emissions. To diagnose and repair leaks, most screening methods must be paired with close-range systems. Differentiating between leaks and venting requires planning and recordkeeping to match detected emissions to planned venting events.

Commenter (0844-EDF *et al.*) states, in general, detection sensitivity declines with spatial scale of measurement, meaning those farthest from the source will be less able to detect smaller emissions. However, there is typically a trade-off between sensitivity and survey speed, and the cost of deployment tends to decline as speed increases. For example, aerial surveys with high detection limits are low cost and can quickly cover broad areas but will only detect the largest emission events, missing smaller leaks.

The commenter (0844-EDF *et al.*) states a major outstanding challenge for screening technologies is their inability to discern vented from fugitive emissions.<sup>298</sup> Under most regulations, including EPA's November 2021 Proposal, venting is authorized in certain limited circumstances, creating potential problems for screening approaches. Detection of permissible high-emission events during screening could trigger follow-up ground surveys for events like blowdowns or tank flashing. Needless searching for these events may increase the cost of screening and disincentivize use of advanced technologies. Reducing instances of permissible emissions through other regulatory standards would alleviate much of this problem, as eliminating permissible venting would enable screening techniques to become more sensitive to the presence of fugitive emissions. Moving toward zero emission standards across the full range of affected facilities could eventually eliminate this issue entirely. Another solution is to reduce detections by screening only for sources that greatly exceed venting limits, relying on ground-based monitoring to resolve smaller events. Rigorous reporting and notification of large events would also allow operators and regulators to know when a high emission event was planned and avoid sending follow-up ground crews if advanced screening detected planned emissions.

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<sup>295</sup> Highwood Emission Management, Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines (2022) <https://highwoodemissions.com/pipeline-report/> [hereinafter "Highwood 2022"].

<sup>296</sup> *Id.*

<sup>297</sup> Fox et al., A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas, 14 *Env. Res. Letters* 53002 (2019), <https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3>.

<sup>298</sup> *Id.*

The commenter (0844-EDF *et al.*) states methane detection methods differ not only in performance but also in the types of sources that can be identified and how these sources are characterized. For example, a recent study using aerial surveys identified far fewer—but much larger—sources than handheld surveys performed at the same time (39 vs 357 sources, respectively).<sup>299</sup> Many of the leaks found during the handheld survey were too small to be seen by aircraft, while many of the largest emission events occurred at a small number of sites and may have been missed during the ground inspection. This indicates that full coverage of a system is most effective with multiple technologies. Simulation studies have shown that a combination of technologies can be effective under the right circumstances.<sup>300</sup>

The commenter (0844-EDF *et al.*) states technologies include deployment platforms and sensor types, while methods include the work practices and follow up procedures. Understanding the methods in combination with a technology is critical when evaluating performance.<sup>301</sup> For example, larger emissions detected during screening must be paired with shorter repair timelines in order to achieve substantial reductions. For certain recurring or major emission events, engineering analysis might be required to diagnose and fix the underlying operational issues. Varying dispatch thresholds for follow-up is another work practice that can greatly influence the effectiveness of an approach. For example, if follow-up and repair is only required for the largest leaks, overall mitigation effectiveness will be lower than a work practice requiring follow-up on all detected leaks.

The commenter (0844-EDF *et al.*) states technologies typically consist of deployment platforms and sensors. Deployment platforms can be broadly classified into the following categories (the commenter provides additional details on each deployment platform in the commenter's letter):

- Aircraft
- Unmanned Aerial Vehicles (UAVs)/Drones
- Mobile Ground Labs (MGLs)
- Continuous Monitoring
- Satellites

The commenter (0844-EDF *et al.*) indicates that sensing modes include point measurement of ambient mixing ratios, path integrated laser-based measurements (active imaging), and column-integrated passive imaging. Sensing modes can be broadly categorized as follows (the commenter provides additional details on each sensing mode in their commenter's letter):

- Point sensing (in plume sensing)
- Active imaging (remote sensing)
- Passive imaging (remote sensing)

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<sup>299</sup> Tyner & Johnson, Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, 55 Env. Sci. Tech. 9773 (2021), <https://pubs.acs.org/doi/10.1021/acs.est.1c01572>.

<sup>300</sup> Fox et al., A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas, 14 Env. Res. Lett. 053002 (2019), <https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3/pdf>.

<sup>301</sup> See id.

- Non-methane

Response I-7-126: EPA acknowledges the commenter's support for the use of alternative technologies. See section IV.B.1 of the December 2022 Supplemental Proposal.<sup>302</sup> Please also see discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies<sup>303</sup>. Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (0932-GHGSat, Inc.) agrees that quantification is an important step in understanding the behavior of the emissions as well as understanding their impact by quantifying the amount that is lost to the atmosphere. In turn, this can help in getting more accurate emissions inventories and having true metrics to compare against the reported progress made in the regional and national commitments on methane reduction. The commenter understands that not all available technology can quantify emissions, including the incumbent OGI technology. Some progress has been made by third-party companies in trying to provide a range of emissions rate based on the different overlays and algorithms masking the OGI reading to interpret the rate. Therefore, technology that is capable of both identifying and quantifying methane emissions, is of the utmost relevance in this regulation.

Commenter's (0932-GHGSat, Inc.) operational satellites and aircraft are capable of meeting this requirement today, as these platforms can detect and quantify methane emissions using peer-reviewed methodologies. In addition, the commenter has a machine learning/artificial intelligence analytics platform that is constantly analyzing vast amounts of data (*i.e.*, big data), with the intention of characterizing each region (in a 2 km-by-2 km grid) and provide current and forecasted data to generate actionable insights. When using the two monitoring platforms in tandem with analytics as part of a facilities' monitoring plan, a robust tiered system is created that allows for frequent monitoring of relevant leaks, while ground inspections can be used as part of maintenance plan rather than a regulatory/enforcement plan.

Response I-7-127: EPA acknowledges the commenter's support for the use of alternative technologies. See section IV.B.1 of the December 2022 Supplemental Proposal.<sup>304</sup> See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies<sup>305</sup>. Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

#### 7.2.2.1 Drones/UAVs

Comment: Commenters (0729-Energy Workforce & Technology Council (EWTC), 0785-John Crane Inc., 0844-EDF *et al.*) discuss the capabilities of UAVs, which have been shown effective in detecting emissions in the oil and gas field.

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<sup>302</sup> 87 FR 74740 (December 6, 2022).

<sup>303</sup> 87 FR 74740-74744 (December 6, 2022).

<sup>304</sup> 87 FR 74740 (December 6, 2022).

<sup>305</sup> 87 FR 74740-74744 (December 6, 2022).



Commenter (0844-EDF *et al.*) makes the point that like manned aircraft, UAVs/drones are not restricted to roads and can complement close-range methods by reaching dangerous or inaccessible places. Some UAV systems use point measurement technologies that directly measure methane concentrations. These point measurement UAVs are often more sensitive than aircraft techniques because of their ability to fly closer to the methane source. The primary limitations for this technology are weather, the distance from the operator, and the relatively short flight times of a few hours (at most). The minimum detection limits for UAVs are in the component-to-equipment-level range of spatial resolution. This technology is readily available and has undergone multiple controlled release tests to verify performance metrics.<sup>306</sup>

Commenter (0785-John Crane Inc.) states UAVs are well suited for proximity ground detection of leaks, quantification, and are unique in their ability to be detect emissions offshore, where aerial technologies are currently incapable. Through the commenter's partnership with SeekOps, they can monitor emissions offshore and offer highly accurate quantification in a variety of environments. When necessary, aircraft or UAV mounted emissions detection can be complemented with stationary or mobile ground technology for a variety of installations, such as gas pipelines, to validate the precise source of emissions.

Commenter (0729-EWTC) notes that since 2018, a team has been utilizing drones equipped with methane detection cameras and sensors in the Permian Basin. It has conducted over 1,000 inspections using drones and drone-mounted sensors, combined with an artificial intelligence (AI) enabled software platform. This effort is contributing to meeting an operator's goals of maintaining methane emissions intensity below 0.2 percent by 2025 and meeting the requirements of the Oil and Gas Methane Partnership (OGMP) 2.0 framework.

Response I-7-128: EPA acknowledges the commenter's support for the use of alternative technologies. See section IV.B.1 of the December 2022 Supplemental Proposal.<sup>307</sup> Please also see section X.B of the preamble to the final rule which details EPA's final standards related to alternative technologies.

#### 7.2.2.2 Aerial

Comment: Several commenters (0756-Baker Hughes, 0785-John Crane Inc., 0826-Kairos Aerospace, 0844-EDF *et al.*, 0915/1290-Bridger Photonics, 0934-Leak Surveys, Inc.) provide detailed information on their aerial technology, including capabilities, limitations and recommended methodologies to be considered under EPA's framework for alternative technologies.

Commenters (0756-Baker Hughes, 0785-John Crane Inc., 0934-Leak Surveys, Inc.) believes aerial technologies provide enough granularity with respect to site level details to distinguish emissions among different assets.

Commenter (0785-John Crane Inc.) believes aircraft mounted surveying offers greater resolution and more flexible monitoring options than satellite, although satellite technology offers high-

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<sup>306</sup> Id.

<sup>307</sup> 87 FR 74740 (December 6, 2022).

level detection of large and super-emitters and low-cost complementary features for the ongoing monitoring of identified emissions. Aircraft mounted leak detection provides economical cover of large geographies against consistent benchmarks. Aircraft mounted surveys are lower cost on a per asset basis, safer (*i.e.*, operators do not need to stand close to the highly flammable methane) and more consistent to use than handheld devices.

The commenter (0756-Baker Hughes) adds for manned or unmanned aerial inspection, OGI or otherwise, multiple companies could share the costs of one flight that covers multiple sites. Site-specific data could then be provided to each asset owner individually.

Commenter (0826-Kairos Aerospace) reports that Kairos Aerospace LeakSurveyor™ system is a light-aircraft mounted, integrated methane gas imaging system capable of detecting medium to large-scale methane emissions. According to the company, the system consists of three integrated measurement devices:

1. An infrared spectrometer calibrated to detect methane,
2. GPS and inertial measurement unit (IMU) to record precise position; and
3. A high-resolution optical camera for visual verification of sites.

The commenter (0826-Kairos Aerospace) notes that the LeakSurveyor™ when mounted on an aircraft can survey up to 150 square miles per day with 3x3 meter methane spatial resolution, detecting emissions at the equipment group and occasionally at the individual equipment scale. Depending on the development density, this could represent thousands of oil and gas facilities per day and hundreds of miles of pipeline. In their comment letter, the commenter provides additional technical details about how the technology detects methane, how data is processed and analyzed, and how methane data is combined with precise location. The combination of data allows the operator to determine the location and likely source of the methane plume while providing important contextual information about ground activity that might be contributing to emissions, such as well maintenance.

Response I-7-129: The EPA acknowledges the commenter's remarks regarding the capabilities of aerial technologies. In response to comments received on the November 2021 Proposal, the EPA proposed an alternative fugitive emissions monitoring and repair program for new, modified, or reconstructed fugitive emissions sources (*i.e.*, collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations) in the December 2022 Supplemental Proposal (See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>308</sup>). These changes include a proposed “matrix” which would specify different screening frequencies corresponding to a range of minimum detection thresholds, in contrast to the single screening frequency and detection level proposed in the November 2021 Proposal. The final rule maintains these requirements mostly as proposed in the December 2022 Supplemental Proposal, with certain edits to the matrix based on additional conducted following the December 2022 Supplemental Proposal.

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<sup>308</sup> 87 FR 74740-74746 (December 6, 2022).

Please also see section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technologies, which includes matrices of minimum detection thresholds of screening technologies and the corresponding minimum screening frequencies.

Comment: Commenter (0826-Kairos Aerospace) provides test results conducted by Stanford University using the Kairos' LeakSurveyor™ in October 2019. Specific information regarding the test itself is available in the commenter's letter. The commenter notes that the final data points and release rates were as follows:

- 35 points below 25 kg/hr-mps wind to assess minimum detection threshold.
- 21 points at 0 kg/hr to assess false positives.
- 165 points above 25 kg/hr-mps wind.

The commenter (0826-Kairos Aerospace) reports that LeakSurveyor™ detected 182 of 200 valid nonzero releases and had no false positives in the 21 negative controls, resulting in an overall detection accuracy of 91.9 percent, with 100 percent detection accuracy for releases above 15 kg/hr/mps wind.<sup>309</sup> The researchers further determined that the 50 percent probability of detection threshold likely occurred between 8.3 and 15 kg/hr/mps. In addition, Kairos' LeakSurveyor™ demonstrated a high level of quantification performance, even without on-the-ground wind measurements and low bias compared to past controlled releases for mobile methane detectors.<sup>310</sup>

The commenter (0844-EDF *et al.*) states passenger aircraft, both planes and helicopters, can be equipped with various sensor technologies and used at various elevations and frequencies. These factors, along with the survey methodologies used, affect survey speed and minimum detection limit. Some aerial technologies or methods may use remote sensing and fly higher and faster or use a technology with a lower sensitivity to cover more sites in a day. Other aerial technologies and methodologies may call for lower and slower flights or use a technology with a higher sensitivity that detects more emission events but covers fewer sites in a day.<sup>311</sup>

The commenter (0844-EDF *et al.*) states the primary limiting factors for aerial methods are weather (high winds, precipitation, cloud cover), variable reflectivity from uneven snow cover, and flight permits. Aircraft detection limits range from a few kilograms of methane per hour to tens of kilograms per hour. This technology is readily available and has undergone multiple, controlled release tests to verify performance metrics. The main advantage of aircraft technologies is the greater geographic coverage, which allows surveying of thousands of sites per day (depending on the infrastructure density). Although aircraft systems are less sensitive than other systems, some aircraft are able to cover large geographic regions rather than targeting only specific sites. This makes it possible to survey entire landscapes for large methane sources that may not otherwise be detected by targeted, site-specific inspections.

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<sup>309</sup> Sherwin et al. 2021.

<sup>310</sup> Id.

<sup>311</sup> Id.

Commenter (0915/1290-Bridger Photonics)<sup>312</sup> has commercialized its aerial light detection and ranging (LiDAR) technology, Gas Mapping LiDAR™, in 2019 as a data product offering, which has been rapidly and broadly adopted by the oil and gas industry in North America over the past three years. The commenter provides a companion document representing a suggested methodology for identification of fugitive methane emissions using aerial remote sensor technology. The commenter hopes the suggested methodology can be used as a framework from which the EPA can construct a comprehensive methodology to support the November 2021 Proposal's alternative work practice using aerial scanning technology.

The commenter (0915/1290-Bridger Photonics) states this protocol is applicable to the detection of methane and, by surrogate, VOC including HAP, and hydrocarbons, such as ethane, propane, and butane. This protocol covers the responsibilities of operators under the protocol regarding aerial remote sensing scans of process equipment in oil and gas upstream and downstream sectors (from production to refining to distribution). The specific component focus for the scans is determined by the applicable subpart, and can include, but is not limited to, valves, flanges, connectors, pumps, compressors, open-ended lines, pressure relief devices, and seal systems. This protocol is applicable to all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities when referenced by an applicable subpart. This protocol is intended to help determine the presence and location of methane and VOC leaks.

In a companion letter, the commenter (0915/1290-Bridger Photonics) provides information representing a suggested methodology for identification of fugitive methane emissions using aerial remote sensor technology.<sup>313</sup>

Commenter (0934-Leak Surveys, Inc.) states Aerial OGI (AOGI) has improved greatly over the last year and is now as effective as a ground survey on well pads and tank batteries. According to the commenter, AOGI surveys are different in that in each assessment the operator can identify each distinct component that is leaking (*e.g.*, leaking components around well sites and tank batteries and leaks from packing valves or gas emitting to the outside of a compressor building or compressor vents on blowdown.)

The commenter (0934-Leak Surveys, Inc.) provides an overview of the technology which is a new high-definition OGI camera and a stabilized gimble, which in combination provides the ability to use the digital zoom features of the camera and allows us to image individual components if needed. This concept is new to the industry and was only introduced to the industry in July of 2021. According to the commenter, AOGI is also the most inexpensive means to conduct a survey if the operator has wells that are in close proximity to each other or if operators cost-share expenses across well sites or fields. The cost associated with AOGI can run as low as \$100 per site, and because of the quality of the video recordings collected there would

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<sup>312</sup> U.S. Department of Health and Human Services. (2010). NIOSH Pocket Guide to Chemical Hazards. NIOSH Publication No. 2010-168c. Also available from <https://www.cdc.gov/niosh/docs/2010-168c/default.html>.

<sup>313</sup> Companion to Comment Letter: Suggested Aerial Remote Sensor Methodology Pertaining to EPA Proposed Rule – Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (86 Fed. Reg. 63110).

be no need to perform a follow-up OGI ground survey, unless the component leaking is not visible in the video. The technology is fast and easy and has the ability to cover approximately 50,000 acres per day and (or) survey a range of 80-130 tank batteries in a single day. Because the information is acquired in real time, the camera operator can immediately notify the operator if a large emission is present or if a flare is malfunctioning; giving the operator the ability to send a field technician to the site for immediate repair. All videos are process within 24 hrs and sent back to the production superintendents for quick repair.

Response I-7-130: In response to comments received on the November 2021 Proposal, the EPA proposed an alternative fugitive emissions monitoring and repair program for new, modified, or reconstructed fugitive emissions sources (*i.e.*, collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations) in the December 2022 Supplemental Proposal (See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>314</sup>). These changes include a proposed “matrix” which would specify different screening frequencies corresponding to a range of minimum detection thresholds, in contrast to the single screening frequency and detection level proposed in the November 2021 Proposal. In addition, EPA proposed to allow owners and operators the option of using continuous monitoring technologies as an alternative to periodic screening and proposed long- and short-term emission rate thresholds that would trigger corrective action. The EPA also proposed monitoring plan requirements for owners and operators that chose to implement the alternative fugitive emissions monitoring approach and proposed to establish a clear and streamlined pathway for technology developers and other entities to seek the EPA’s approval for the use of advanced measurement technologies under this alternative option. The final rule maintains these requirements mostly as proposed in the December 2022 Supplemental Proposal, with certain edits to the matrix based on additional conducted following the December 2022 Supplemental Proposal.

For periodic screening using advanced methane detection technology, the final rule allows for the use of multiple detection technologies, instead of requiring the owner or operator to choose one technology, allowing end-users to optimize their periodic screening program by choosing the most suitable technology based on time of year and availability of technology providers. The periodic screening frequency will be based on the technology with the highest aggregate detection threshold that the owner or operator lists as a technology they plan to use in their monitoring plan.

Please also see section X.B of the preamble to the final rule which details EPA’s final standards related to advanced methane detection technologies, which includes matrices of minimum detection thresholds of screening technologies and the corresponding minimum screening frequencies.

#### 7.2.2.3 Other Technologies

Comment: Several commenters (0429-Picarro, Inc., 0748-American Fuel & Petrochemical Manufacturers (AFPM), 0844-EDF *et al.*) urge EPA to incorporate flexibility under the

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<sup>314</sup> 87 FR 74740-74746 (December 6, 2022).

alternative technologies program and provide information on additional technologies that are capable of identifying and detecting methane emissions.

Commenter (0429-Picarro, Inc.) believes Advanced Mobile Leak Detection (AMLDD) is an important part of the solution set that operators need to identify and quantify methane emissions. A suite of technologies is needed to address the methane emission identification and quantification for the upstream and midstream sectors, for which no single tool will suffice because of several factors such as density of assets, limitations of resolution and sensitivity, and lack of proven results and accuracy for the various technologies. The commenter highlights AMLDD's comparative benefits to other measurement technologies:

- Greater accuracy and higher efficiency than traditional methods.
- Capable of more rapid deployment than alternative technologies.
- Sensor technology is less susceptible to weather-related interference than other technologies.
- Greater versatility and effectiveness than fixed-site technologies with comparable sensitivity.
- Higher resolution visualization technology for identifying and grading emission sources
- Compatible with other technologies to provide a more complete and effective solution.

The commenter (0429-Picarro, Inc.) believes it is critical for EPA to adopt a definition for AMLDD that reflects currently available technology. In their comment letter, the commenter discusses the key attributes of AMLDD technology, including a high methane sensitivity, the ability to use of the weather parameters combined with GPS technology for determining leak location, emission rate, and survey coverage areas, as well as their analytics and models used produce reliable and actionable leak survey and methane emissions data.

The commenter (0429-Picarro, Inc.) reports that their AMLDD technology solution is a proven and viable vehicle-mounted system that conducts multiple patrols through a natural gas infrastructure, collecting methane plume data and sending it to the Picarro analytics platform. The Picarro AMLDD system identifies the characteristic signatures of natural gas leaks by analyzing the methane plumes as they propagate in the atmosphere and intersect with the path of the vehicle. The system also measures atmospheric and meteorological conditions and uses algorithms to identify the origin and degree of hazard of the natural gas leak indication while virtually eliminating indications triggered by other non-natural gas sources of methane. The AMLDD technology solution should be able to accurately quantify emission rates.

According to the commenter (0429-Picarro, Inc.), more than 60 double-blind, directed field trials with 33 operators across North America, Europe, Asia, and Australia, several involving independent, third-party validation by Gas Technology Institute, NYSEARCH, Pipeline Research Council International, Inc. and others, the Picarro solution consistently found 3 times more grade 1 and grade 2 leaks than traditional survey techniques.

The commenter (0429-Picarro, Inc.) believes AMLDD is more effective than traditional leak survey at identifying gas leaks because it reduces human error, eliminates errors associated with asset record inaccuracies, and employs a more sensitive sensor.

Commenter (0748-AFPM) indicates that there are other emerging technologies being developed. One such technology is leak detection sensor network (LDSN).<sup>315</sup> The EPA should place a discussion in the preamble language encouraging such LDAR alternative technology development and the proper means of approval from the EPA for deployment. The commenter (0844-EDF *et al.*) states MGLs are defined as any stationary or mobile ground-based vehicle (car, truck, van, ATV, *etc.*) equipped with a methane sensor and a GPS. Typically, MGLs will also measure environmental conditions, especially wind speed, wind direction, temperature, and humidity. MGLs can take an active or passive approach to surveying. The active approach entails MGLs driving a predetermined route along the infrastructure to be monitored, while the passive approach entails mounting sensing equipment on vehicles performing unrelated tasks, like delivery trucks.<sup>316</sup>

Response I-7-131: EPA acknowledges the commenters support for the use of alternative technologies and recognize that there are many different technologies available. EPA has taken this comment into account as they designed the alternative technology program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>317</sup> Please also see section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technologies, which includes adoption of flexible frameworks and specific requirements that must be provided in the request for approval of alternative test methods.

### ***7.2.3 Technology-Neutral/Matrix Approach***

Comment: Commenters (0454-Kayros, 0558-C2ES, 0588-Project Canary, 0593-Our Nation's Energy Future (ONE Future), 0604-Providence Photonics, LLC (Providence), 0610-Oxy, 0747-Centre for Smart Emissions Sensing Technologies, University of Calgary (SENST), (0760-Airdar *et al.*, 0765-Institute of Clean Air Companies (ICAC), 0768-Methane Roundtable, 0781-NTAA, 0782-BHE, 0801-Carbon Mapper/RMI, 0807-BP, 0810-Petroleum Alliance-OK, 0814-IPAA *et al.*, 0826-Kairos Aerospace, 0828-Union of Concerned Scientists (UCS), 0830-Devon Energy, 0831-AXPC, 0846-Arolytics Inc., 0922-National Association of Manufacturers (NAM), 0938-TXOGA, 1375-Kinder Morgan, Inc.) believe it is important to emphasize that technologies will continue to be developed in the future to comply with leak detection standards. Some commenters add that it is critical that EPA rules are designed to ensure the standard is technology neutral, which will encourage facility operators to continuously innovate and find better solutions for emissions reduction.

The commenters (0610-Oxy, 0801-Carbon Mapper/RMI, 0807-BP, 0826-Kairos Aerospace, 0938-TXOGA) recommend that EPA adopt a screening protocol with a matrix approach that would allow operators to trade higher frequency sampling and increased spatial coverage for higher detection limits. This flexibility could reduce overall monitoring costs while expanding

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<sup>315</sup> This technology is mentioned in the October 13, 2021, Federal Register notice, "Notice of Request for Approval of Alternative Means of Emissions Limitation."

<sup>316</sup> *Id.*

<sup>317</sup> 87 FR 74740-74746 (December 6, 2022).

the available pool of monitoring technologies, thus increasing overall detection completeness and mitigation potential.

The commenter (0454-Kayros) states given the respective and inherent limitations of all methane detection technologies, the ideal methane surveillance system must blend inputs from various types of sensors to combine their respective advantages and overcome their limitations.

The commenter (0610-Oxy) encourages a technology-neutral matrix framework that would allow for varying survey frequencies based on the resolution of the technology. This ensures that operators are not limited or restricted in their ability to identify and deploy those technologies that are best suited to their specific assets or operating conditions (*e.g.*, the ability to leverage automation and remote sensing to direct operators to highest priority sites for maintenance, repair, and response.) A technology-neutral approach also better allows for incorporation of future innovation in LDAR technologies.

The commenter (0747-SENST) believes that EPA should undertake detailed research (testing, piloting, and modeling) to develop alternative standards with screening methods. There is unlikely to be a one-size-fits-all standard given the diversity of screening methods. The commenter (0768-Methane Roundtable) recommends EPA address or seek input on the following in the supplemental rule proposal:

- How should EPA develop a compliance and enforcement framework for this rule that ensures consistency across the BSER options and any advanced technology pathways?
- How should EPA use/not use emissions data submitted as part of this rule?
- What tools should EPA use to determine source-specific compliance (*e.g.*, compliance certifications, annual emissions reports, an emissions-based performance standard (“bubble” concept))?
- Should EPA align this CAA section 111 rule with subpart W and ensure that future changes to subpart W will not require subsequent changes to this rule?
- What is the appropriate inspection and survey frequency for maintaining emission reduction progress?
- How should EPA determine whether an emissions detection requires response by an operator to repair the emissions source or whether the emission is permissible (*e.g.*, associated with a maintenance action)?
- How can EPA support the use of a combination of technologies (known by some as “tiered observations”) across regions or operations to assess overall compliance at regional scale?

The commenter (0801-Carbon Mapper/RMI) recommends that EPA adopt a system of systems (tiered observing system) approach that combines the attributes of airborne and satellite remote sensing for detection and quantification of large emission events along with surface sensor networks optimized for identifying lower emission activity across the oil and gas value chain.

Commenter (0814-IPAA *et al.*) believes that adopting a single, one-size-fits-all technology standard for alternative screening technologies is limiting not just to the success of the regulatory design, but also limiting to the development and deployment of domestic technologies aimed at



minimizing the compliance cost to the sector. In the space of alternative leak detection technologies, it is important to employ an outcomes-based regulation, rather than a prescriptive design (*i.e.*, leak detection technology thresholds). Focusing on the intended outcome of the regulation allows for multiple different technologies to be used for leak detection over large geographic areas, while minimizing cost to industry.

The commenter (0814-IPAA *et al.*) encourages the EPA to consider the growth of the technology and service sector in the design of forthcoming regulations. Consider how domestic innovation and employment are impacted by strong regulatory design that is both flexible enough to allow for multiple solutions to be deployed in the field while ensuring that the regulation is achieving its intended environmental impacts. This approach allows the EPA to have strong yet flexible standards that better suit today's technologies as well as future technologies that are being developed.

The commenter (0810-Petroleum Alliance-OK) adds the goal of emission monitoring technologies is to find and fix leaks quickly; however, a mandated, "one-size-fits-all" emission monitoring requirement may not meet that goal or work in every scenario or for every size of operator.

The commenter (0807-BP) encourages EPA to consider an integrative and flexible approach when assessing technologies for regulatory compliance purposes, as different technologies are better suited to different asset types, operations and applications. EPA can maximize the effectiveness of a more flexible monitoring approach by focusing on the desired outcome, as opposed to prescribing specific technology types. By focusing on the outcome, namely emission reductions, EPA can enable operators to leverage multiple technologies and deliver the desired emissions reduction goals in the most cost-effective, safe, and operationally efficient manner.

The commenters (0807-BP, 0831-AXPC) state that by adopting a matrix-based approach, EPA will allow operators to use a variety of technologies and work practices that will achieve a functionally equivalent or better result.

The commenter (0807-BP) adds that a matrix approach also provides EPA with a framework to evaluate future technology options that may not yet exist today, or that may not be commercially viable at scale yet. The commenter believes there are combinations of emissions detection thresholds and inspection frequencies that can achieve equivalent or greater emissions reductions than semiannual and quarterly OGI surveys. For example, LDARSim modelling by Kairos Aerospace, an aerial methane monitoring company, indicates a range of inspection frequencies and minimum detection thresholds that are estimated to be equivalent to the emissions reductions affiliated with quarterly OGI. The results indicate that a technology that monitors more frequently than the current quarterly OGI surveys can have a higher emissions detection threshold and still achieve the same emission reduction results. Therefore, the commenter supports EPA creating a matrix with additional minimum detection thresholds/inspection frequency combinations, including a higher threshold detection technology deployed more frequently.

The commenter (0826-Kairos Aerospace) states Highwood Emissions Management performed an analysis using its LDAR Simulator (LDAR-Sim) model to estimate the emissions reduction performance of a broad range of possible screening LDAR configurations.<sup>318</sup> The commenter argues LDAR-Sim is an improvement over other modeling platforms because it allows for practical considerations that vary by producer, facility, environment, and policy context, such as inspection time, snow cover, cloud cover, and low solar irradiance. It also allows the user to combine multiple inspection programs, such as periodic aerial surveys plus annual OGI inspections. Moreover, LDAR-Sim directly compares emissions under two or more monitoring programs, rather than comparing each program against a null scenario. This is preferable because a true “null scenario” rarely exists in the real world, as operations are already subject to some type of monitoring program.<sup>319</sup> The commenter finds Highwood’s analysis demonstrates that it is feasible to achieve emissions mitigation equivalent to or better than EPA’s proposed quarterly OGI-only program with a range of configurations of aerial survey frequencies and minimum detection limits.

The commenter (0830-Devon Energy) states that given the potential of technologies to effectively detect and reduce the occurrence of significant methane emission events, a matrix approach that couples screening frequency with detection sensitivity, along with appropriate analysis and follow-up, can provide the maximum amount of flexibility and will encourage broader adoption of such technologies. This approach will drive continuous improvement and potentially lead to more effective LDAR programs over time.

The commenter (0846-Arolytics Inc.) states EPA has laid out a “canned” approach to alternative LDAR that is methodology focused. The EPA approach has considered outcomes in its design by listing the required minimum detection limit required for an alternative technology, but the approach itself is not outcome-based. Producers/operators can adopt the approach, or not. For most, the canned alternative LDAR approach is probably more expensive. The commenter believes with the singular canned formula, EPA could be inadvertently selecting for one or two specific aerial technology vendors that meet the defined detection limits and selecting against many other vendors who do substantially better and relegating their businesses to investment plays where they might offer benefit to clients in different contexts.

The commenter (0846-Arolytics Inc.) suggests that based on the EPA formula for alternative LDAR, and looking out at the experience in other jurisdictions, the EPA approach may have several unintended consequences:

- Low uptake by producers who realize that the canned alternative is more expensive for their asset class.
- High uptake by producers who realize that the canned alternative is likely to result in fewer and less expensive repairs, based on their asset class.

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<sup>318</sup> Fox, Thomas A., Mozhou Gao, Thomas E. Barchyn, Yorwearth L. Jamin, and Chris H. Hugenholtz, “An AgentBased Model for Estimating Emissions Reduction Equivalence Among LDAR Programs,” *Journal of Cleaner Production*, 282 (2021) 125237 (Available online December 5, 2020). <https://doi.org/10.1016/j.jclepro.2020.125237> (hereinafter, “Fox et al. 2021”).

<sup>319</sup> *Id.*

- Stagnation in the technology space where EPA in effect selects for one or two technology winners that have moderate to low detection capabilities (but high throughput).

Response I-7-132: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>320</sup>

Comment: Commenter (1299-Methane Emissions Leadership Alliance (MELA)) believes Alberta Energy Regulator (AER's) Directive 060 strikes a good balance of creating pathways for new technology while maintaining a rigorous enough process to ensure successful environmental outcomes. During the Methane Reduction Oversight Committee process, the commenter indicates that they discussed at length the merits and shortcoming of "outcome based" regulations versus "prescriptive" regulations and the AER determined that a hybrid model was the best approach. Currently, the AER regulations are prescriptive, thereby ensuring that certain facility types are inspected at certain frequencies (based on a triage defined by PTE). However, the AER left open an "outcome based" compliance option for fugitive leak detection called: The Alternative Fugitive Emissions Management Plan (alt-FEMP). The alt-FEMP option has been open to industry for the past year. The process has allowed AER to review and approve multiple new screening technologies for use in the field, with a consistent eye towards ensuring these new technologies do not inhibit the intent of the current regulatory design.

The commenter (1299-MELA) suggests the use of emission mitigation modeling to provide an effective tool to compare technologies and establish programs that will ensure new leak detection solutions are continuing to meet EPA goals and minimizing the cost to industry.

Response I-7-133: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>321</sup> Please see discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>322</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach.

Comment: Commenter (0826-Kairos Aerospace) states in order to assess the performance of alternative technologies, EPA and other stakeholders need transparent, independently validated performance data on methane detection systems. This validation is a key first step before any technology should be used to ensure compliance with EPA regulations. The commenter has gone

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<sup>320</sup> 87 FR 74740 (December 6, 2022).

<sup>321</sup> 87 FR 74740 (December 6, 2022).

<sup>322</sup> 87 FR 74740-74744 (December 6, 2022).

through independent third-party validation and the third-party has independently published the results of that work following peer review.<sup>323</sup>

Response I-7-134: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>324</sup> Please see discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>325</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach.

Comment: Commenter (0801-Carbon Mapper/RMI) assessed the effectiveness of the alternative screening protocol by analyzing over 2,500 large emission oil and gas methane sources detected and quantified by multiple airborne remote sensing surveys of representative oil and gas production basins across the U.S. that are collectively responsible for about 40 percent of U.S. onshore production in 2019.<sup>326</sup> Each source in this population had instantaneous methane emission rates as low as 10 kg/hr. The commenter's analysis used previously published methods<sup>327</sup> extended to additional surveys through fall 2021, with all data sets published on the Carbon Mapper public data portal.<sup>328</sup>

The commenter (0801-Carbon Mapper/RMI) estimates the average emissions from that population of large emission sources to be  $3.4 \pm 1.1$  million metric tons of methane per year, equivalent to about 43 percent of total oil and gas production emissions reported in EPA's GHG inventory for 2019 and consistent with the commenter's estimates of the average relative contributions of strong point sources to regional scale emissions using independent top-down atmospheric estimation methods. These emissions occur in every production segment. These findings, when combined with other studies that indicate the EPA methane inventory for this sector may be under-estimated by 60 percent (Alvarez *et al.*, 2018) suggests that large emission methane sources may account for at least half of the U.S. oil and gas methane budget, underscoring the importance of screening for large emission events.

The commenter (0801-Carbon Mapper/RMI) adds the percentage of large methane emission sources that should be detectable with a given screening protocol is a function of detection limit, spatial coverage, and sampling interval (measurement frequency). The commenter provides extensive details on various concepts and calculations in their comment letter surrounding their analysis, ultimately describing and arriving at the conclusion that alternative screening methods with improved detection completeness are needed.

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<sup>323</sup> Sherwin, Evan, Yuanlei Chen, Arvind P. Ravikumar, and Adam R. Brandt, "Single-Blind Test of Airplane-Based Hyperspectral Methane Detection Via Controlled Releases," *Elementa Science of the Anthropocene*, 2021 ("Sherwin *et al.* 2021").

<sup>324</sup> 87 FR 74740 (December 6, 2022).

<sup>325</sup> 87 FR 74740-74744 (December 6, 2022).

<sup>326</sup> EIA, 2021.

<sup>327</sup> Duren *et al.*, 2019, Cusworth *et al.*, 2021.

<sup>328</sup> <https://carbonmapper.org/data/>.

The commenter (0801-Carbon Mapper/RMI) believes that EPA's November 2021 Proposal for alternative screening is limited to well sites and compressor stations which is likely to miss at least 40 percent of large emission fugitive sources covered by this rule given the prevalence of large emissions observed for other key equipment types. Hence, the commenter recommends that the alternative screening protocol be expanded to cover all onshore production equipment including well sites, compressor stations, storage vessels, flares, and gas processing plants. The commenter also notes that while methane emissions from gathering pipelines are under the jurisdiction of the Pipeline and Hazardous Materials Safety Administration rather than EPA, much of this important production segment would automatically be sampled by many remote sensing systems given their proximity to well sites and compressor stations. The commenter believes that incentivizing operators to adopt high frequency sampling protocols could identify intermittent malfunctioning hardware, provide a quantitative performance assessment of mitigation progress, and increase overall detection completeness to nearly 90 percent. The top-down quantification capabilities of remote sensing from satellites and aircraft would offer critical additional insight beyond conventional OGI surveys that tend to be limited to providing qualitative information about leak locations. For example, such quantification could be pivotal in verifying progress against the 95 percent emission reduction targets for storage vessels, pneumatic devices, and flares. Improved quantification of large emission, high frequency anomalous sources can also be used to validate and improve process equivalency models<sup>329</sup> that can in turn be used to guide proactive emission avoidance action rather than relying solely on reactive LDAR programs.

The commenter (0801-Carbon Mapper/RMI) compared potential annual total costs and per site average costs for the three in a screening matrix for a notional monitoring program for 1000 sites in a single company defined area assumed to be confined within a 1000 km<sup>2</sup> contiguous area with roughly even spacing of production sites. The commenter's letter includes *Table 1-Proposed matrix of requirements for alternative screening methods for large emission sources*, with three options presenting a range of cost based on the commenter's assessment of average per site survey costs for current and expected near-term monitoring systems. The commenter assesses that both remote sensing (+ single annual OGIs survey) options represent substantial cost savings compared to quarterly OGI surveys but with significantly improved completeness.

The commenter (0801-Carbon Mapper/RMI) recommends a system of systems approach that combines the attributes of airborne and satellite remote sensing for detection and quantification of large emission events along with surface sensor networks optimized for identifying lower emission activity across the oil and gas value chain.

Response I-7-135: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>330</sup> Please see discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>331</sup> Please also see section XI.B of the preamble to the final rule

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<sup>329</sup> e.g., FEAST; Kemp et al, 2016; LDARSIM, Fox et al, 2021; AROFemp, Lavoie et al, 2021.

<sup>330</sup> 87 FR 74740 (December 6, 2022).

<sup>331</sup> 87 FR 74740-74744 (December 6, 2022).

which details EPA’s final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach.

Comment: Commenter (0846-Arolytics Inc.) notes that EPA seems to have followed two assumptions in alternative LDAR regulatory design. It’s useful to clarify those assumptions and weigh them against experience in other jurisdictions.

1. Alternative programs are costly, and models are complicated. This assumption is untrue. The Alberta experience shows that cost savings from Alternative LDAR Programs can be significant. For all but the very smallest producers, the upfront costs for that design, testing, proving, will be recouped normally in the first year of program implementation. To overcome these initial hurdles, and to realize the cost incentive, a producer/operator must invest in knowledge capital to get the project started. Education is the biggest barrier. A producer/operator with knowledge, and good supports, will be better equipped to meet its methane targets.
2. One size CAN fit all. Again, this assumption is untrue. One size may fit all in a broad modelling exercise, but a model probably assumes that implementation will be even, and occurring at a certain rate. But the incentives to adopt alternative monitoring pathways are very uneven and differ by producer/operator. In general, those with the most incentive to adopt are those who will see reductions in detection “hits”, which will translate to reduction in follow-up mitigation cost. Of course, mitigation costs are generally higher than detection costs so it might be worth spending extra on monitoring to avoid mitigation expenditures.

Overall, based on the experience in other jurisdictions, the commenter (0846-Arolytics Inc.) recommends a process more like Alberta’s:

- Flexible in terms of work-practice, frequency of screening, and technology used, so as to find the best pathway for effective LDAR that is custom to a specific operator.
- Program implementation-based rather than technology based.
- Outcome-based as to let the proponents be the experts, and in charge. The EPA can determine how they define equivalency and enable a diversity of programs to be approved that meet the required outcomes.
- Knowledge based where producer/operator, and EPA, are knowledgeable about tools and programs.
- Innovative, with space for models and other advanced tools to demonstrate equivalency, and where one method or model doesn’t automatically win.
- Clearly defined criteria for acceptance to deploy an alternative program, including a clearly defined reporting framework.

Response I-7-136: EPA acknowledges the commenters support for the use of alternative technologies, including specific recommendations. EPA has taken this comment into account as they designed the alternative technology program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>332</sup> Please also see section X.B of the preamble to the final rule

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<sup>332</sup> 87 FR 74740-74746 (December 6, 2022).

which details EPA's final standards related to advanced methane detection technologies, which includes adoption of flexible frameworks.

#### 7.2.3.1 Advanced Technologies Should Complement OGI/Method 21 Monitoring

Comment: Commenters (0391-KBIC, 0781-NTAA) support the use of advanced technologies, but used as a complement to the required monitoring until the technologies are more proven. Once the advanced technologies are proven, the owner/operator can submit them for approval as an equivalent alternative method. The commenter feels this is important to protect fenceline communities from the HAP associated with oil and natural gas emissions.

The commenter (0782-BHE) believes it is imperative that innovation not compromise program integrity. Innovation cannot come at the expense of methodological and programmatic development of alternative technologies and survey approaches. The commenter suggests that EPA initiate a program to support technology and leak mitigation program development and standardization, rather than adopt new approaches in this rulemaking.

The commenter (0922-NAM) states operators should be encouraged to allow sources maximum flexibility for selecting options for detection and leak repair technologies. This should also allow companies to share some of these technologies, devices or systems to identify and repair the leaks. The commenter also encourages EPA to allow the use of advanced technologies, like continuous monitoring, as an alternate to OGI.<sup>333</sup>

The commenter (0593-ONE Future) believes it is important to deploy a practical framework that does not assume that a certain technology will work in every instance and region. It is important for EPA to provide flexibility and regulatory context for operators to quickly deploy innovative technologies. As the commenter's work and experience has shown, some technologies, while promising, are not yet commercially viable. For instance, satellites can capture large methane plumes associated with known blowdown events for maintenance but aren't yet advanced enough to capture smaller leaks that operators are driven to find and fix. While commenter (0593-ONE Future) supports EPA's November 2021 Proposal to allow flexibility in the use of advanced technologies, the use of OGI cameras will continue to be a critical tool for operators to find and manage leaks. Being overly prescriptive on the use of OGI could hinder operators' ability to utilize the tool effectively, which we suggest could be a step backward.

The commenter (0828-UCS) notes in the years since EPA first expanded coverage to include methane emissions from oil and gas sources, monitoring technologies have significantly improved, affording ever-increasing identification and granular resolution on the sources of leaks throughout the sector. This expanded visibility has revealed the shocking scale of the problem and galvanized the need for robust interventions. It has also made clear the insufficiency of early data collection approaches, and the value of expanded leak-identification pathways. As EPA finalizes this rule, it must ensure that leak identification methodologies meet robust minimum operating standards while keeping the door open to a broad array of options, including independently operated leak identification efforts such as satellites and aerial surveys.

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<sup>333</sup> For example, the NAM encourages the EPA to allow sources the option to use Method 21 as an alternate to Optical Gas Imaging.

Furthermore, for sources where equipment malfunctions can occur without ties to routine operating events, the agency should ensure that monitoring frequency enables sufficiently rapid detection for quick repairs—including, as feasible, continuous monitoring.

Response I-7-137: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>334</sup> Please also see section XI.B of the preamble to the final rule which details EPA’s final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds where annual OGI would also be required.

Comment: Commenter (0775-CDPHE) believes alternative screening methods (*e.g.*, aerial surveys) should complement, and not yet completely replace, traditional IR camera/AIMM inspections. The commenter also has concerns with the specificity of the protocols for EPA’s November 2021 alternative screening proposal. The commenter suggests that EPA instead let states have the flexibility to employ alternative screening after individualized review of the appropriateness of the technology, frequencies, follow-up and repair timelines, as is most effective in the region and for the sites for which the alternative screening is deployed. The commenter does not believe that EPA approval of a state’s approval of alternative screening methods is necessary or should be required.

Response I-7-138: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>335</sup> Please also see section XI.B of the preamble to the final rule which details EPA’s final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds where annual OGI would also be required.

Comment: Commenter (0782-BHE) adds because existing source regulations will likely result in EPA’s voluntary methane reduction programs becoming obsolete, new program or method development could be implemented through pilot studies under the umbrella of the Methane Challenge program. The commenter also recommends addressing challenges related to ensuring leak detection and mitigation programs during program development, such as standard methods and equivalency definitions for measurement and monitoring technologies; the decision basis for leak repair alternatives or tier-based programs that consider “leak size;” and standard practices and procedures (*e.g.*, training, certification) for implementation.

Response I-7-139: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. Please also see section

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<sup>334</sup> 87 FR 74740 (December 6, 2022).

<sup>335</sup> 87 FR 74740 (December 6, 2022).



XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds of the screening technology.

Comment: Commenter (0932-GHGSat, Inc.) understands that simulation models can assist in the understanding of monitoring equivalence. Kemp *et al.*, found that the cost effectiveness of tiered LDAR programs can achieve equivalent emissions reductions at lower costs when compared with OGI only by varying survey frequency.<sup>336</sup> The purpose of the equivalence model is to analyze the different technologies and understand if the alternative tiered approach is cost-effective when compared to the default technology. The default technology is an OGI camera, as currently mandated by US regulations, with a frequency of four surveys per year. The commenter asked a third-party analytics company to perform a methane emissions equivalency report utilizing GHGSat's aircraft technology and corresponding capabilities. The executive summary of this equivalency modeling is included in Appendix B of the commenter's letter. Overall, the modeled results showed the cost-effectiveness of implementing GHGSat's aircraft technology six times per year and one annual OGI survey, as proposed by this rule. Using the alternate technology resulted in same methane reductions but at two thirds of the cost when compared to typical OGI surveys costs.

Response I-7-140: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>337</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds where annual OGI would also be required.

Comment: Commenter (0763-TCEQ/RRC) encourages allowing EPA Method 21 to remain an option for fugitive monitoring, as this EPA method is integrated into LDAR programs recognized in the commenter's authorization mechanisms used for emissions representations in permitting programs. Removing EPA Method 21 as a fugitive monitoring method would increase the regulatory overlap, as authorization mechanisms do not allow for the use of OGI fugitive monitoring outside of the Alternative Work Practice in 40 CFR §60.18.

The commenter (0763-TCEQ/RRC) supports the use of advanced measurement technologies and alternative screening approaches for fugitive monitoring with verification using OGI or other fugitive emission monitoring programs; however, this technology is not currently recognized in state authorization mechanisms and would be in addition to EPA Method 21 monitoring required by state authorization mechanisms and LDAR programs. The commenter has concerns on how these advanced measurement technologies would be implemented and verified and the additional

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<sup>336</sup> Kemp, et al., 2021.

<sup>337</sup> 87 FR 74740 (December 6, 2022).

requirements applicable for monitoring and operation of these technologies creating a burden on review of representations.

Response I-7-141: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>338</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds where annual OGI would also be required.

#### ***7.2.4 Costs of Advanced Technologies***

Comment: Commenters (0831-AXPC, 0844-EDF *et al.*, 0915/1290-Bridger Photonics) provided feedback related to the widespread availability of advanced technologies and specific information on costs.

Commenter (0831-AXPC) reports that costs associated with six-times-per-year aerial survey plus one OGI is greater than the cost of quarterly OGI and will disincentivize the use of alternative technology. The commenter recommends three or four times-a-year frequency, which would likely yield greater emissions reductions than with four OGI surveys on the ground and operators would realize a cost savings, which would further incentivize the use of new technology.

Commenter (0844-EDF *et al.*) notes that advanced monitoring technologies are already widely available and in use by leading operators.<sup>339</sup> Many of these technologies are highly effective and inexpensive. And many companies providing advanced methane mitigation services are domestic and provide well-paying jobs in geographies across the country. These technologies are particularly capable and efficient at screening large areas for emissions, although layered approaches utilizing multiple techniques may be most appropriate for finding and fixing smaller (but collectively significant) leaks. Operator experience, scientific use and testing, and simulation modeling provide estimates of the cost and effectiveness of different approaches that can inform regulatory approaches.

The commenter (0844-EDF *et al.*) cites a recent comprehensive survey from Datu Research shows that advanced leak detection services are widely-available. Datu's survey of services firms offering advanced methane monitoring reveals their ability and plans to scale up in response to new federal methane regulations.<sup>340</sup> Firms offering advanced monitoring services have nearly doubled in the past four years alone, and more than a quarter are already capable of surveying

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<sup>338</sup> 87 FR 74740 (December 6, 2022).

<sup>339</sup> See Datu Research, Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry (2021); EPA, Methane Detection Technology Workshops, <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>.

<sup>340</sup> Marcy Lowe, Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up, Datu Research (July 22, 2021), [http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey\\_Datu-Research\\_8-10-2021.pdf](http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_Datu-Research_8-10-2021.pdf)

over 300 well sites per day. More than half of firms surveyed said they could serve at least 100 more well sites per day than they currently serve by 2023. Nearly half (47 percent) said they could scale up to serve more than 500 well sites per day; these respondents comprised those using fixed sensors, airplanes, satellites, or a combination of these technologies. Eighty-nine percent of the firms surveyed can detect emissions at the equipment level, while 53 percent can detect at the component level. According to the research cited by the commenter, the firms also operate broadly across major oil and gas basins, with at least 32 percent having a presence in every basin, and 74 percent operating in the Permian.

The commenter (0844-EDF *et al.*) also points to EPA's 2021 Methane Detection Technology Workshop and summarizes the following key takeaways and conclusions:

- Layered approaches are needed.<sup>341</sup>
- Advanced technologies are cost-effective and significantly reduce emissions.<sup>342</sup>
- Comprehensive coverage is already deployed by leading operators.<sup>343</sup>
- Workshop cost estimates:
  - OGI – \$600/site/inspection<sup>344</sup>
  - Aerial – \$100-300/site, quarterly for \$1,600/facility<sup>345</sup>
  - Drone – \$2,700-3,500/annually<sup>346</sup>
  - Continuous – \$1,000-5,000 annually<sup>347</sup>

Commenter (0915/1290-Bridger Photonics) performed a detailed analysis and comparison of both cost and emissions reduction between the standard quarterly OGI program and the aerial alternative work practice in the proposed rule using Bridger's Gas Mapping LiDAR [(1 × OGI) + (6 × GML)]. The main conclusions include a lower gross GML program cost, large net savings when gas is recaptured, and low cost per ton of emissions reduced. Specific details on these main conclusions are included in the commenter's letter.<sup>348</sup>

The commenter (0915/1290-Bridger Photonics) also highlights other benefits associated with alternative programs that are not easily quantified, including safety, efficiency, impact, objectivity, insensitivity to temperature, and self-auditing.<sup>349</sup>

Response I-7-142: EPA acknowledges the information provided by commenters related to the use of and cost of different alternative technology solutions. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection

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<sup>341</sup>See *id.* (presentations by: David Lyon, Erin Tullos, Matt Johnson, Triple Crown, Jonah, Project Astra, Project Falcon, BPX, Conoco, and Exxon).

<sup>342</sup>See *id.* (presentations by: Triple Crown, TRP, Jonah, BPX, Conoco, and Exxon.).

<sup>343</sup>See presentations by: Triple Crown, Jonah, BPX, Conoco, and Exxon.

<sup>344</sup>*Id.* (Erin Tullos and Arvind Ravikumar).

<sup>345</sup>*Id.* (Erin Tullos, Arvind Ravikumar, and Matt Johnson (TRP \$1,600/facility/quarterly)).

<sup>346</sup>*Id.* (TRP).

<sup>347</sup>*Id.* (Erin Tullos and TRP).

<sup>348</sup>The commenter also provides a supplemental information spreadsheet (EPA-HQ-OAR-2021-0317-0166\_attachment\_11).

<sup>349</sup>EH&S Diversified Energy Company expresses support of Bridger's comments which are attached to EH&S comment letter (EPA-HQ-OAR-2021-0317-0915).

technologies.<sup>350</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of alternative technologies for detection of fugitive emissions under the advanced methane detection technology program, and section XI.B.1.b of the preamble to the final rule for a specific discussion on technology flexibility.

### ***7.2.5 Periodic Screening Frequency***

Comment: Commenter (0915/1290-Bridger Photonics) recommends that EPA adopt quarterly rather than bi-monthly scan frequency until sufficient temporal data exists to inform policy.

The commenter (0915/1290-Bridger Photonics) notes that due to uncertainty in the modeling, and the financial, operational, and logistical burden on the industry for an “instant” ramp up to bi-monthly scanning, the commenter urges the EPA to adopt quarterly rather than bi-monthly scan frequency in the final rule (in addition to annual OGI) for the alternative aerial work practice as long as (a) the adopted detection sensitivity metric is no worse than 10 kg/hr with >50 percent probability of detection in typical conditions, and (b) there is a built-in mechanism to change (increase or decrease) that scan frequency when the aggregate temporal data becomes available to establish that a different scan frequency achieves the goal of detecting 75 percent of annual emissions. The commenter also advocates more generally for a built-in mechanism to allow individual operators with demonstrated low emissions to use lower scan frequencies.

The commenter (0915/1290-Bridger Photonics) also emphasize that Bridger’s aerial scans have been demonstrated in typical operational conditions to perform better than a one-to-one replacement for OGI scans. Yet the aerial scanning AWP in the November 2021 Proposal implies that two aerial scans replace each of three OGI surveys (*i.e.*, 1:2 swap). If EPA’s intent is to use OGI scans as the benchmark for performance, then quarterly scanning plus annual OGI is certainly more than justified. This is supported by third-party studies showing that Bridger’s aerial LiDAR scans detect more, not less, emissions than OGI scans with ground crews.<sup>351</sup> Moreover, the same study finds that the aerial scans result in far fewer repair events due to the larger emission events uncovered by Bridger’s scans. These findings have been repeated on much larger scale with consistent results.<sup>352</sup>

Response I-7-143: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>353</sup> Please also see section XI.B of the preamble to the final rule which details EPA’s final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds for screening frequencies.

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<sup>350</sup> 87 FR 74740-74746 (December 6, 2022).

<sup>351</sup> David R. Tyner, et al., Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, *Environmental Science & Technology* 2021 55 (14), 9773-9783 DOI: 10.1021/acs.est.1c01572.

<sup>352</sup> Matt Johnson group at University of Carleton, manuscript in preparation.

<sup>353</sup> 87 FR 74740 (December 6, 2022).

Comment: Commenter (0740-UPA) states the November 2021 Proposal would require alternative screening surveys using advanced measurement technology to be done every other month.<sup>354</sup> The commenter argues this frequency is too high, puts an unnecessary burden on operators and especially on smaller operators who have less flexibility among their workforces, a burden made worse by the labor shortage, and conflicts with the need described above to be able to employ different technologies for each monitoring event throughout the year. Leak detection monitoring with advanced measurement technologies should require no more than the same frequency as leak detection by other methods.<sup>355</sup>

Response I-7-144: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>356</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds for screening frequencies.

Comment: Commenter (0932-GHGSat, Inc.) believes an important part of the proposed revision is that the program is designed to focus monitoring efforts on sites and equipment that are most likely to have large emissions. The commenter agrees that an effective method of reducing emissions is by monitoring and detecting the larger leaks, which tend to occur stochastically and sporadically, but when they occur tend to considerably affect the emissions inventory of an entity. The commenter notes this effect has been observed in different studies, in which the effects of few large events can correspond to comprehend more than 50 percent by volume of the methane emitted (Brandt, *et al.*, 2016). Using Brandt's study and accounting for EPA's proposed 10 kg/hr threshold for alternative monitoring methods, this can provide an opportunity to detect more than 90 percent by volume of the methane emitted. The commenter agrees with the proposed revisions in the sense that they provide owners and operators with the flexibility to use advanced technologies that can find major leaks more rapidly and at a lower cost than ever before.

Response I-7-145: EPA acknowledges the commenters' support for the November 2021 Proposal's standards related to alternative methane detection; because comment is supportive, no response is required.

Comment: Commenter (0391-KBIC, 0428-Kirk Frost, 0781-NTAA, 0788-350 Seattle, 0796-Asthma and Allergy Foundation of America – Michigan Chapter (AAFA-MI) *et al.*, 1330-Catskill Mountainkeeper) believe that the shortest duration of time between monitoring should be used in the final rule. Because many large emission events occur because of leaking

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<sup>354</sup> Proposal, p. 63175.

<sup>355</sup> A modeling study using the LDARSim model shows that EPA's proposed alternative screening surveys using advanced measurement technology six times per year results in a far more rigorous LDAR program than quarterly OGI monitoring. See "EPA OOOOb/c Alternative Monitoring Recommendations" by Ryan Streams, January 13, 2022, located at [https://kairos aerospace.com/wp-content/uploads/2022/01/KairosEPA-OOOOb-c-Recommendations\\_220112\\_FINAL.pdf](https://kairos aerospace.com/wp-content/uploads/2022/01/KairosEPA-OOOOb-c-Recommendations_220112_FINAL.pdf) (accessed on January 27, 2022).

<sup>356</sup> 87 FR 74740 (December 6, 2022).

equipment, longer monitoring periods would allow leaks to continue to emit unchecked for longer periods of time. Commenter (0796-AAFA-MI *et al.*) stresses requiring frequent monitoring and modern/zero-emitting equipment is critical to protecting public health.

Response I-7-146: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>357</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds for screening frequencies.

Comment: Commenter (0586-Navajo EPA)) supports the November 2021 Proposal to use advanced measurement technologies for well sites and compressor stations on a bimonthly basis, provided that these advanced measurement technologies are demonstrated to detect leaks to the same degree that OGI would (at a low level of emissions).

Response I-7-147: EPA acknowledges the commenter's support. In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>358</sup> Please also see section XI.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology, which includes the finalization of technology-neutral matrix approach, and the specific combinations of screening frequencies and minimum detection thresholds for screening frequencies.

Comment: Commenter (0425-Darrah) states the more flexibility EPA provides in methods of monitoring the easier it will be for operators to comply with the rule. Flexibility will allow for more innovation in monitoring methods as well as reduced costs in monitoring with more diversity in options.

Response I-7-148: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>359</sup>

Comment: Commenter (0747-SENST) recommends EPA develop a rigorous, transparent methodology and metrics to estimate emissions reductions from different screening programs relative to the proposed BSER or another benchmark. The commenter asserts that EPA must assess the logistical feasibility and costs of programs that incorporate screening surveys, follow-up at flagged sites, and full annual OGI at all other sites emitting greater than or equal to 3 tpy not flagged by screening methods. The commenter also says that EPA should develop a rigorous,

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<sup>357</sup> 87 FR 74740 (December 6, 2022).

<sup>358</sup> 87 FR 74740 (December 6, 2022).

<sup>359</sup> 87 FR 74740 (December 6, 2022).

transparent methodology to estimate the full cost of screening programs using a common metric for program evaluation such as cost to emissions mitigation ratio (\$/t CO<sub>2</sub>e).

Response I-7-149: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>360</sup>

Comment: Commenter (0801-Carbon Mapper/RMI) recommends adding an option for bi-weekly (14 day) remote-sensing surveys with a 100 kg/hr detection limit would provide equivalent detection completeness to bi-monthly surveys with a 10 kg/hr detection limit. Both approaches would achieve a cumulative completeness of nearly 90 percent. The commenter finds that both bi-weekly and bi-monthly remote sensing surveys would likely provide dramatically better overall detection completeness compared to quarterly OGI surveys, largely because of the limited spatial and temporal completeness of the latter. The commenter's analysis suggests that detailed, spatially and temporally resolved models of oil and gas upstream and midstream infrastructure could be used to further optimize for detection completeness between the 10 and 100 kg/hr detection limit and bi-weekly and bi-monthly sampling targets.

Response I-7-150: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>361</sup>

Comment: Commenter (0777-Ascent) supports EPA's November 2021 Proposal to provide for alternative screening for fugitive emissions sources using advanced measurement technologies; however, as described in the November 2021 Proposal, EPA is proposing a significant impediment to the program that will serve as a disincentive to the regulated community.

The commenter (0777-Ascent) notes that the frequency of the aerial screening (and potential associated ground-based OGI surveys) is too high to properly incentivize the regulated community. The November 2021 Proposal would require quarterly (or in some cases semiannual) OGI monitoring as the "default." Conducting aerial surveys six times per year, with the potential for ground-based OGI follow-up surveys – in addition to the mandated full OGI ground survey that must be conducted irrespective of the results of the aerial surveys – threatens to add to the burden of fugitive emission monitoring when compared to the default regulatory requirement.

For that reason, commenter (0777-Ascent) recommends that the EPA propose quarterly, rather than bimonthly, aerial surveys as part of the alternative screening method. The EPA should embrace these advanced technologies and promote their use by regulated community. One way to do that would be to relieve the burden associated with those technologies by reducing the frequency of required aerial screening from bimonthly to quarterly.

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<sup>360</sup> 87 FR 74740 (December 6, 2022).

<sup>361</sup> 87 FR 74740 (December 6, 2022).

The commenter (0777-Ascent) argues quarterly aerial surveys will ensure monitoring takes place on at least the same frequency as the default regulatory requirement for most sites, while at least potentially allowing owners and operators to conduct that monitoring more efficiently with the advanced measurement technologies.

Response I-7-151: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>362</sup>

Comment: Commenter (0831-AXPC) has concerns with EPA's singular approach of requiring that the alternative must meet a minimum threshold of 10 kg/hr and be conducted bimonthly along with an annual site-by-site survey utilizing OGI. The commenter says EPA's justification for this threshold and frequency as comparable OGI surveys in yielding emission reductions is unclear. Many of these technology companies are able to produce data that demonstrates the effectiveness of their technologies even at higher thresholds and/or less frequent surveys than those proposed. In these cases, a bimonthly requirement with an annual OGI would be much more stringent than, rather than comparable to, the corresponding proposal for a quarterly LDAR requirement utilizing OGI. The commenter believes a frequency of three or four times a year is a more comparable to quarterly OGI surveys, based on even conservative modeling estimates.

The commenter (0831-AXPC) adds a bimonthly frequency for something like flyover screening technologies, creates operational feasibility challenges to execute when also considering the associated timelines for data processing, quality assurance/quality control (QA/QC) analysis, and on-the-ground follow-up and repair. Depending on the number of sites surveyed, flyovers generally take seven-to-ten days depending on the weather, and then often another ten days before the data is received. Operators must then analyze the information provided before they can send out teams to make repairs. Under the November 2021 Proposal, companies would only have a few days for repairing leaks across an entire survey area, which is not practically feasible and significantly shorter than the timeframe provided for walk-around OGI surveys. On a bimonthly cadence, realistically, operators would still be working to perform repairs when it comes time to do the next flyover, creating material operational inefficiencies and shrinking the emission reduction per survey with the overlap.

Responses I-7-152: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>363</sup>

Comment: Commenter (0785-John Crane Inc.) recommends that total site-level baseline emissions thresholds should be used to determine frequency of monitoring, and subsequently allow alternative emissions screening technology for the same. Prescriptive policies that dictate

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<sup>362</sup> 87 FR 74740 (December 6, 2022).

<sup>363</sup> 87 FR 74740 (December 6, 2022).



specific technologies could potentially disincentivize emissions reduction from large quantities of emissions left out of scope.

Response I-7-153: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>364</sup>

Comment: Commenter (0826-Kairos Aerospace) studied the percent of emissions mitigated by performing four, five, and six aerial surveys per year, with and without annual OGI. Two distribution models were used: The Chen *et al.* Permian distribution and Omara distribution, both discussed in further detail in the commenter's attachment. The Permian distribution shows aerial surveys exceeding performance of OGI under all scenarios. The modeling report states, "we recommend that the EPA consider the average mitigation, as the Omara distribution does not consider super-emitters known to exist, which are of high consequence to overall emissions. Programs with average emissions in bold are deemed to reduce emissions to a greater extent than the EPA's regulatory OGI program."

Based on this approach, the commenter (0826-Kairos Aerospace) provides a matrix of sensitivities and survey frequencies that will achieve at least equivalent emission reductions compared to quarterly OGI surveys. While the Permian distribution supports detection limits of greater than 40 kg/hr at a variety of frequencies and sensitivities, the commenter has selected a more cautious approach that gives additional weight to the Omara results, despite these being conservative due to a lack of super emitters. The commenter's reasoning is that the Permian may have more super emitters than other basins, and despite representing nearly half of U.S. oil production, EPA may want to take an approach that does not solely rely on the Permian as the basis for an emission distribution.

The commenter (0826-Kairos Aerospace) states the proposed table within the commenter's document attempts to strike that balance between the Permian and Omara modeling results but is arguably more heavily weighted towards the Omara results in order to provide EPA a more conservative framework. The commenter does believe EPA could select higher detection limits and still achieve equivalence, but their work here is intended to provide EPA a well-reasoned and conservative starting point for a matrix-based approach to alternative leak detection requirements.

Response I-7-154 In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>365</sup>

Comment: Commenter (0846-Arolytics Inc.) notes that some new gas methane certification standards already require alternative measurement of different types, at frequencies beyond those of regulation. These market-based standards may cause significant friction with EPA's approach

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<sup>364</sup> 87 FR 74740 (December 6, 2022).

<sup>365</sup> 87 FR 74740 (December 6, 2022).

in that the market-based approaches may propose different technologies and frequencies. If a producer/operator wants to adopt a standard that achieves a far better methane reduction outcome than the EPA's approach but must be added in parallel to EPA's inflexible regulatory approach, this provides disincentive for the producer/operator to pursue the market-based certification standard because the producer/regulator would have to implement and pay for both programs. These producers/operators with an interest in these standards, and better methane performance than their peers, should have the ability to show, with modelling and/or field results, that their more rigorous certification-related practices meet or exceed the EPA's rules.

Response I-7-155: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>366</sup>

### ***7.2.6 Minimum Detection Threshold***

Comment: Commenter (0811-ABB) believes EPA should comprehensively study commercially available methane leak detection technologies to understand the features in the current state-of-the-art. This will inform what minimum detection thresholds should be part of an EPA regulatory regime. The commenter urges EPA to consider establishing as rigorous a minimum detection threshold as commercially available technologies allow and also consider other important performance parameters such as time response, linearity, and overall accuracy.

Response I-7-156: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>367</sup>

Comment: Commenters (0785-John Crane Inc., 0932-GHGSat, Inc.) recommend adopting the threshold of 10 kg/hr as it is inclusive of many types of commercial technologies and detection modalities appropriate for surveying all manner of asset types included in the proposed regulations.

The commenter (0932-GHGSat, Inc.) reports that there are functional and commercially available aircraft technology capable of meeting that threshold right now. For example, GHGSat's aircraft-based sensor has been flying over multiple U.S. oil and gas basins since 2019. The aircraft sensor technology has a nominal detection threshold of 10 kg/hr (an order of magnitude better than the satellite) and a pixel resolution of two feet.<sup>368</sup>

Response I-7-157: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane

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<sup>366</sup> 87 FR 74740 (December 6, 2022).

<sup>367</sup> 87 FR 74740 (December 6, 2022).

<sup>368</sup> Id.

detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>369</sup>

Comment: Commenters (0586-Navajo EPA, 0835-CMES, 0935-COGA) express concern whether the proposed threshold of 10 kg/hr is appropriate.

The commenter (0586-Navajo EPA) is concerned whether the minimum detection threshold of 10 kg/hr is sufficient to detect leaks that are still significant and would be detected by OGI. Provided these measurement technologies are properly able to detect fugitive emissions in an equivalent degree as OGI, the increased frequency of these measurements should help detect leaks sooner and lead to quicker repairs.

The commenter (0835-CMES) is concerned that if the proposed threshold of 10 kg/hr is implemented, their experience in the field indicates that many leaks (more than 90 percent of all leaks) would be missed. The commenter believes a gap of this size is unnecessary and EPA should consider revising it.

Commenter (0935-COGA) believes EPA's November 2021 Proposal to require a minimum detection threshold of 10 kg/hr for alternative technologies is not technically supported and should be reconsidered. Detector sensitivity is only one factor impacting the effectiveness of a leak detection program and should not be considered in isolation. Program effectiveness is also impacted by inspection frequency, software algorithms, and particularly the ability to detect large emission events. The alternative standard should allow the use of any alternative leak detection technology or program where modeling shows that it will achieve equivalent or better emission reductions than OGI.

Response I-7-158: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>370</sup>

Comment: Commenter (0775-CDPHE) states that detection sensitivity can vary based on conditions in the field, which must be accounted for with each alternative screening advanced measurement technology if detection sensitivity is to be used as a basis at all for any requirement in the proposed regulation. Currently, Colorado requires controlled and field testing results confirming the detection threshold of the technology. The commenter's position on advanced screening is that advanced screening must be looked at as part of a holistic program to minimize emissions. The commenter believes that finding and mitigating emissions involves more than simple focus on a detection threshold, especially in terms of the method and work practice(s) used with or for the monitoring technology. The commenter encourages EPA to refer to the information provided through the EPA Methane Detection Workshop held July 2021 for initial information provided by several technology providers about detection thresholds. The commenter also suggests that EPA convene a workgroup across states and technology providers

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<sup>369</sup> 87 FR 74740 (December 6, 2022).

<sup>370</sup> 87 FR 74740 (December 6, 2022).

to come up with guidance for states and operators seeking to employ alternative screening in their LDAR programs -outside of the regulation.

Response I-7-159: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>371</sup>

Comment: Commenter (0826-Kairos Aerospace) states the proposed requirement for a 10 kg/hr sensitivity is infeasible because it would require a fleet of approximately 250 aircraft flying at extremely low altitudes to implement on a national scale. This would be very difficult to implement while adhering Federal Aviation Administration safety requirements on aircraft spacing.

The commenter (0826-Kairos Aerospace<sup>372</sup>) utilizes a passive infrared spectrometer system, which allows for higher altitude flight and wider survey swath widths when compared to active measurement systems. Passive systems survey a larger area in a single pass and more facilities in a single flight day compared to active measurement systems. The Kairos system can detect leaks as small as 2 kg/hr under ideal conditions, but it cannot perform at 10 kg/hr under all normal operating conditions. Meeting the 10 kg/hr standard under all conditions would create several significant technical and economic hurdles and would not provide commensurate environmental benefit.

The commenter (0826-Kairos Aerospace) notes EPA's November 2021 Proposal to use a fixed minimum detection limit does little to ensure equivalence. Equivalence should be assessed by evaluating overall program performance, not by evaluating the detection sensitivity as an isolated variable. The Appendix K Technical Support Document prepared for EPA by Eastern Research Group acknowledges that "the detection limit of an OGI camera can be thought of as more of a continuum versus a single point."<sup>373</sup> Similarly, Dan Zimmerle of Colorado State University noted that "[l]eak detection solution performance should be characterized as an integrated solution, not as a 'sensor' or a 'deployment method.'" In addition, "[a]nalytics will have as much or more impact on the performance than the sensor or the deployment."<sup>374</sup> Comparative modeling performed by Highwood shows equivalence of airborne technologies at much higher detection thresholds.

The commenter (0826-Kairos Aerospace) fully supports EPA's decision to approach the detection limit question with a flux-based unit of measurement rather than a concentration-based measurement. A concentration-based metric such as ppm is inappropriate for evaluating instrument performance because the concentration varies spatially and temporally, making it difficult to select a representative concentration. In addition, a concentration metric does not capture the size of the leak point; a high-concentration pinhole leak may emit less than a low-

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<sup>371</sup> 87 FR 74740 (December 6, 2022).

<sup>372</sup> Note that a duplicate letter from the commenter appears in the docket as EPA-HQ-OAR-2021-0317-1374.

<sup>373</sup> Appx. K TSD at 48.

<sup>374</sup> Zimmerle, Daniel, CSU Energy Institute, Next-Generation Leak Detection Solutions, slide 8.

concentration leak from a larger opening, such as an open thief hatch. Flux-based approaches more accurately capture remote sensor performance in real world conditions.<sup>375</sup>

Response I-7-160: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>376</sup>

Comment: Commenter (0831-AXPC) states that minimum detection threshold should be based on modeling (e.g., FEAST, LDAR-Sim) that demonstrates that the alternate technology is expected to achieve the required emission reductions.

Response I-7-161: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>377</sup>

Comment: Commenter (0826-Kairos Aerospace) states small leaks contribute little to the total emissions rate; system-wide emissions and emission reductions are dominated by large emission events (LEEs) that can be observed using low-sensitivity sensors. Chen *et al.* reported that leaks of at least 308 kg/hr are responsible for 50 percent of total methane loss, while Cusworth *et al.* 2021 and Duren *et al.* 2019 observed a similarly skewed distribution.<sup>378</sup> A detection sensitivity of 10 kg/hr is not necessary to find 308 kg/hr leaks. If a large proportion of total methane is coming from leaks emitting hundreds of kg/hr or greater, the difference in performance between a system with a 5 or 10 or 25 kg/hr detection limit is of little significance, as those relatively small leaks do not represent a significant portion of overall emissions. Rather, speed and efficiency at identifying and eliminating LEEs are the most important metrics for an effective aerial screening program.

Response I-7-162: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>379</sup>

Comment: Commenters (0604-Providence, 0831-AXPC, 0932-GHGSat, Inc., 0938-TXOGA) note that consideration of the detection limit for technologies should be a principal consideration in establishing the required intervals. This would ensure that the requirements are sufficient to identify and quantify methane emissions without being needlessly burdensome.

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<sup>375</sup> See also Appx. K TSD at 46 (“A detection limit in ppm-m is limited in its usefulness, whereas a detection limit in grams per hour (gph) is more important in assessing emission factors.”).

<sup>376</sup> 87 FR 74740 (December 6, 2022).

<sup>377</sup> 87 FR 74740 (December 6, 2022).

<sup>378</sup> Cusworth et al. 2021.

<sup>379</sup> 87 FR 74740 (December 6, 2022).

The commenter (0604-Providence) notes that the key to achieving a successful and equitable outcome is to set the detection threshold and screening frequency in such a manner so that the net emissions between the alternative screening options and the ground-level OGI based compliance method required by this rule will be equivalent. The commenter notes that the 10 kg/hr threshold is either much too high, or the frequency must be much higher than the proposed bi-monthly schedule to provide equivalency. The commenter encourages EPA to conduct a more detailed analysis to support both the threshold and frequency for advanced measurement technologies so that the matrix provides equivalent environmental benefit to the baseline OGI program. The commenter hope that such analysis will also include a scenario in which the frequency will be high enough (*e.g.*, hourly, 15-minute) to include new technologies that provide continuous leak monitoring. This would establish a threshold and mechanism for any advanced technology which can provide continuous monitoring of fugitive emissions, allowing for the potential to provide the same (or better) environmental benefit at a lower cost to the operator.

Response I-7-163: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>380</sup>

Comment: Commenter (0932-GHGSat, Inc.) believes that a minimum detection threshold must incorporate a more representative limit by incorporating a specific probability of detection, with a proposed unit of mass emission rate of methane per wind speed or mass emission rate of methane referenced to a specific winds speed be accompanied by a probability of detection and by a referenced wind speed or the minimum detection threshold expressed as mass emission per unit of wind speed. The commenter proposes the following:

- Minimum detection threshold of 4 kg/hr/m/s with 50 percent probability of detection; and
- Minimum detection threshold of 8 kg/hr/m/s with 90 percent probability of detection.

Response I-7-164: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>381</sup>

Comment: Commenter (0747-SENST) urges EPA to carefully investigate the effect of a fixed minimum detection threshold for screening methods versus a matrix of minimum detection thresholds versus survey frequency should be based on a rigorous assessment of real or potential emissions reductions. In addition, the commenter recommends that EPA determine if a fixed minimum detection threshold is futureproof because as emissions decrease with time progressively lower minimum detection threshold will be needed to support future reductions.

The commenter (0747-SENST) further suggests that EPA distinguish between a screening technology and a screening method and develop standard tests and test criteria for evaluating detection sensitivity and real or potential emissions reductions. If requiring a minimum detection

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<sup>380</sup> 87 FR 74740 (December 6, 2022).

<sup>381</sup> 87 FR 74740 (December 6, 2022).

threshold, the commenter suggests that EPA explicitly define how this minimum detection threshold relates to the more common probability of detection (POD) curves, which account for uncertainty. Additionally, the commenter recommends that EPA require that detection performance and uncertainty are established using independent single-blind controlled release testing. Testing should be designed to account for factors that affect detection sensitivity and representative operating envelopes, in the commenter's opinion. The commenter states that EPA should require that detection methods be aware of and control for the conditions that increase the minimum detection threshold or lower the POD to ensure that performance is not adversely affected, and important leaks are missed. Lastly, the commenter indicates that EPA must differentiate between minimum detection threshold or POD and follow-up threshold. Screening methods with minimum detection thresholds that are lower than the regulated level may require the use of emissions quantification to flag facilities for follow-up (or other approaches), but quantification accuracy and uncertainty are not well constrained for most screening technologies presently.

Response I-7-165: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>382</sup>

#### ***7.2.7 Follow-Up OGI Survey***

Comment: Commenter (0586-Navajo EPA) supports the use of an expeditious follow up OGI if fugitive emissions have been detected. The commenter also supports the continued use of full OGI at least annually, if not more frequently (*e.g.*, semiannually).

Several commenters (0391-KBIC, 0781-NTAA, 0943-Sault EPD) also believe that the use of OGI technologies should be emphasized over EPA Method 21 for monitoring and that Method 21 should not be used for follow-up surveys after emissions were detected. The commenters believe OGI is more efficient and effective at identifying leaks and fugitive emissions.

Response I-7-166: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>383</sup>

Comment: Commenter (0932-GHGSat, Inc.) understands the need to repair, as soon as practicable, methane emissions sources detected with alternative monitoring technologies. The commenter agrees with the understanding that large emissions events contribute disproportionately to the overall emissions within a region and/or facility. The commenter wants to comment on the classification of leaks based on severity and the associated tiered repair deadlines. The categories and tiered repair deadlines proposed provide for the repair deadline flexibility proposed in this rule, but with increased emphasis and sense of urgency on repairing the largest. Therefore, the commenter agrees that the process of scheduling repairs at compressor stations should be tiered based on the severity of the emissions found.

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<sup>382</sup> 87 FR 74740 (December 6, 2022).

<sup>383</sup> 87 FR 74740 (December 6, 2022).

The commenter (0932-GHGSat, Inc.) proposes a 15-day deadline for the first repair attempt for emission between 10 and 100 kg/hr of methane. This, deadline gives an extra day in case the OGI survey is conducted near the 14-day limit and materials and/or replacement parts are not available. Please note that a tighter deadline is proposed for equal or larger than 100 kg/hr methane leaks.

Response I-7-167: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>384</sup>

Comment: Commenters (0777-Ascent, 0780-LongPath<sup>385</sup>, 0785-John Crane Inc. LLC, 0807-BP) urge EPA to consider flexibility surrounding the requirements for the follow-up ground-based OGI survey.

The commenter (0777-Ascent) indicates that the deadline to complete the follow-up ground-based OGI survey in the November 2021 Proposal's alternative screening method is another disincentive for the regulated community. In the commenter's opinion, allowing only 14 days from aerial survey to conducting the full ground-based OGI survey will create compliance concerns for the regulated community. The time period to process and evaluate the data generated by an aerial survey can vary greatly, depending on what technology and vendor conducts the survey. Based on past experience, Ascent expects that it will take up to 10 days from the completion of the aerial survey to identify the sites for which a follow-up survey is required. Taking into account the potential for a survey to trigger ground-based surveys at multiple sites, Ascent Resources is concerned about a scenario where it would simply not have enough time to complete all the ground-based follow-up surveys within 14 days of the aerial survey.

For that reason, the commenter (0777-Ascent) suggests that EPA propose a deadline to conduct the follow-up OGI survey of 45 days from the screening survey. Extending that deadline would have little, if any, environmental impact, while eliminating a deadline that the commenter considers a significant disincentive to the November 2021 Proposal's alternative screening program – particularly for those larger companies that would survey many sites at the same time.

The commenter (0780-LongPath) adds if a matrix approach is undertaken, then regions of the matrix with higher frequency of readings (faster refresh rate, for example, continuous monitors) could be paired with a wider set of follow-up options before the requirement of an OGI visit. This is justifiable given the more detailed wealth of information and context regarding emissions that is afforded by continuous and higher-frequency monitors.

The commenter (0785-John Crane Inc.) recommends adopting a 30-day deadline for the first year of rule implementation as the number of assets requiring OGI surveys would be increasing significantly and the OGI infrastructure across companies may not be scaled appropriately for some time.

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<sup>384</sup> 87 FR 74740 (December 6, 2022).

<sup>385</sup> Note that a duplicate letter from the commenter appears in the docket as EPA-HQ-OAR-2021-0317-0933.



The commenter (0785-John Crane Inc.) recommends the EPA adopt a tiered structure that is component/repair type specific rather than emissions level specific as some large emitters are able to be repaired very quickly whereas some process components require shutting down an operation for extended periods, or other highly disruptive process changes that require extensive planning, and intermediate or temporary solutions for emissions control until equipment overhaul or replacement can be completed.

The commenter (0807-BP) adds EPA should include an OGI follow-up survey exemption in the advanced screening proposal to address proven, intermittent emissions events. Under EPA's November 2021 Proposal, an OGI operator would be dispatched to a wellsite within 14 days of an emission detection from an advanced measurement survey. However, in some instances, the emissions detected during an advanced measurement survey may be intermittent — in some instances, not persisting beyond the duration of the survey itself. For example, water dump valve actuation or routine operational repairs may result in gas being discharged intermittently. Given the short emissions duration, these events should not require a follow-up OGI inspection. The commenter estimates that approximately 75 percent of detected fugitive methane emissions at its U.S. onshore sites come from detections on separators, heater treaters and well heads that are intermittently venting. Given the short duration of these intermittent events, by the time an OGI operator is deployed to the site the emissions source may be resolved.

The commenter (0807-BP) argues if intermittent emissions events can be corroborated by another technology or data source, and this two-step verification is appropriately documented by the operator, regulations should provide for an exemption from the follow-up OGI survey. For example, compressor or planned equipment blowdowns are permitted events that may be captured by aerial surveillance. However, based on the imagery provided by the vendor and available Supervisory Control and Data Acquisition (SCADA) data the commenter is able to determine, with sufficient confidence, that the emissions are connected to a known, planned, intermittent event. So that this exemption is employed only in appropriate circumstances, EPA may wish to require reasonable recordkeeping that would be available to regulators upon inspection.

As safety is a top priority for commenter (0807-BP), it is important to identify opportunities that minimize their employee and contractor drive time, which is a leading cause of fatality in the commenter's industry. If the commenter is required to send people out to sites despite having collected and recorded sufficient data evidence to demonstrate that an emissions source no longer persists, the commenter may be creating additional and avoidable safety risk to their people.

Response I-7-168: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>386</sup>

Comment: Commenters (0775-CDPHE, 0830-Devon Energy, 0932-GHGSat, Inc., 1267-CA AG *et al.*) suggest that flexibility be provided around the timing for follow-up survey based on the severity of the leak.

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<sup>386</sup> 87 FR 74740 (December 6, 2022).

The commenter (0775-CDPHE) questions whether one time frame is sufficient to address the myriad of issues that arise from advanced screening. For example, for just one site, the commenter believes that 14 days is generally too much time; Colorado's regulations require either first attempt at repair or completed repair within five days of detection of a leak. The commenter recognizes that under certain circumstances it is possible that aerial surveys could detect a significant number of emission events that would require a follow-up inspection, and that it may not be feasible to conduct all follow-up inspections within a truncated time frame. If an operator is scheduling certain advanced screening, such as aerial monitoring, it may be appropriate for that operator to also plan to have follow-up survey teams ready to deploy to visit locations with detected emissions within a reasonable timeframe. EPA may also want to consider tiering requirements for follow-up surveys so that those locations with the highest or most severe emissions are visited first. To reiterate, the commenter believes that programmatic flexibility is inherently necessary.

The commenter (0775-CDPHE) generally recommends that repair deadlines be advanced from EPA's November 2021 Proposal. Colorado's repair deadlines are also more stringent for leaks detection within 1,000 feet of an occupied area or within a disproportionately impacted community. If EPA established a tiered requirement for follow-up OGI surveys, then a tiered repair deadline may not be necessary. If there is no tiered requirement for follow-up surveys, then the commenter would agree that it would be appropriate to prioritize repair of the most severe or egregious fugitive emissions. The commenter notes that the "severity" of the fugitive emissions as detected by a monitoring technology can be variable based on field conditions, such as wind and weather, but also the location of the source. Because EPA would need to account for these variations and not simply rate or volume of emissions, the commenter reiterates the need for state flexibility in crafting appropriate advanced screening protocols to appropriately address the environmental and health impacts of fugitive emissions.

The commenter (0830-Devon Energy) encourages EPA to consider whether the proposed follow-up and repair timeframes are appropriate in every circumstance, particularly given the large amount of data obtained during a flyover screening survey. Operators should be given flexibility to prioritize those events with the highest estimated emission rate when using technologies that have the capability of providing a quantification estimate. Lower priority emission events (*i.e.*, those events with a lower estimated emission rate) should be allowed additional time for follow-up so that available operator resources can be utilized to address higher estimated emission rate events first.

The commenter (0932-GHGSat, Inc.) believes that EPA should consider implementing deadlines for first and final attempts for repairing and verifying the leak based on severity regardless of the component type or infrastructure. Satellite monitoring can detect the largest leaks (greater or equal than 100 kg/hr) and notify operators more quickly than other methods. This in turn could trigger a rapid repair response followed by OGI to verify the repair and survey the entire site, the latter representing an opportunity to detect lower emission rates synergistically.

Commenter (1267-CA AG *et al.*) recommends that EPA require a shorter repair period if the well site is located in proximity to an already overburdened community in terms of the follow-up survey. For instance, Colorado regulations require that a first attempt at the repair of a leaking

component be made within five days if a site is located within 1,000 feet of an occupied area or within a disproportionately impacted community.<sup>387</sup>

Response I-7-169: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>388</sup>

Comment: Commenter (0830-Devon Energy) encourages EPA to consider how operators should follow up on methane emissions events detected by advanced continuous, near-continuous, and non-continuous detection technologies. In many cases, the cause and mitigation of an identified emission event can be determined remotely using operational information, including SCADA data, negating the need for a follow-up OGI inspection. This has an additive safety and environmental benefit of reducing the number of miles driven and the resulting emissions from travel to and from the site in question.

Response I-7-170: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>389</sup>

Comment: Commenter (0807-BP) states EPA should clarify regulatory text indicating follow up actions within 14 days of “receiving the data” from the alternative screening survey. In the supplemental rule, EPA should clarify that the 14-day window for a follow-up OGI survey commences upon the operator’s receipt of the advanced screening survey results from the vendor. There are situations where operators may not receive the final survey data from third-party vendors on the day of inspection. Should the language remain as written, delays in data receipt could unintentionally consume several days afforded in the 14-day window for follow-up OGI surveys. In so doing, operators would end up with less time to execute follow-up surveys. Assuming the intent is to provide operators with a full 14 days to perform the follow-up surveys, EPA should clarify that this window begins at the time of data receipt, not the survey itself.

Response I-7-171: See the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>390</sup>

### ***7.2.8 Incentivize Advanced Technology***

Comment: Commenter (0787-Atmos<sup>391</sup>) believes that the EPA should incentivize the use of advanced fugitive emissions monitoring technology. It is crucial that EPA make it as easy as possible for companies to quickly adopt and install advanced fugitive emissions monitoring technologies. For context, the commenter installed a Gas Cloud Imaging (GCI) system<sup>392</sup> in 2021 at a large storage and compression facility that can identify leaks from up to 1.7 miles away and continuously scans the site using pan and zoom functions to provide real-time leak detection

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<sup>387</sup> 5 Colo. Code Regs. §§ 1001-9:D.II.E.6.f-g, II.E.7.b (adopted Dec. 17, 2021).

<sup>388</sup> 87 FR 74740 (December 6, 2022).

<sup>389</sup> 87 FR 74740 (December 6, 2022).

<sup>390</sup> 87 FR 74740 (December 6, 2022).

<sup>391</sup> Note that a duplicate letter from the commenter appears in the docket as EPA-HQ-OAR-2021-0317-1280.

<sup>392</sup> Honeywell, GCI – Standard, <https://sps.honeywell.com/us/en/products/safety/gas-and-flame-detection/gas-cloudimaging/gci-standard>.

This technology is far more sensitive than the 10 kg/hr threshold that EPA proposes.<sup>393</sup> The GCI camera's advanced imaging technology analyzes hyperspectral data from every pixel at a rate of 60 times per second to identify more than 50 gases, each of which have a unique emission in the long-wave infrared spectrum that the camera detects.<sup>394</sup> Additionally, the GCI camera depicts the size of the gas cloud and the direction the plume is moving in real time.<sup>395</sup> Removing barriers to companies installing such systems like the current application process would benefit the environment and further the purpose of the November 2021 Proposal.

Response I-7-172: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative methane detection technologies, including where EPA specifically discussed the goal of incentivizing new technologies, plus requested additional feedback from owners and operators on ways to improve and further incentivize use of alternative technologies.<sup>396</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of alternative technologies for detection of fugitive emissions under the advanced methane detection technology program, and section XI.B.1.b of the preamble to the final rule for a specific discussion on technology flexibility.

Comment: Commenter (0610-Oxy) believes streamlining the use of advanced measurement technology framework will allow for increased efficiencies for the on-going surveys. The proactive approach of reducing fugitive potential is more effective than increased survey frequency. Compared to facilities with higher potential for fugitives, the commenter believes lower emitting facilities should have reduced survey frequency. However, the commenter does see value in on-going surveys at these locations and does not think a one-time survey is appropriate.

Response I-7-173: See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on alternative methane detection technologies, including where EPA specifically discussed establishing a clear and streamlined pathway for EPA approval for the use of advanced measurement technologies alternative periodic screening and alternative continuous monitoring. Under this alternative screening option. Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of alternative technologies for detection of fugitive emissions under the advanced methane detection technology program.

Comment: Commenter (0844-EDF *et al.*) indicates that by incorporating a flexible alternative, which may be more cost-effective for many operators and is likely to become less expensive over time, EPA can support innovative new approaches that will allow LDAR and methane mitigation markets to grow and become more efficient. EPA can also set parameters that achieve reductions equivalent to or greater than OGI in a manner that can further spur development of new technologies. Building in this flexibility will ensure that new technologies can qualify for regulatory use and will allow companies to innovate around clear parameters. A strong OGI-based BSER that rests on longstanding analytical methods and relies on proven technologies and

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<sup>393</sup>86 Fed. Reg. at 63,175.

<sup>394</sup>Honeywell, Honeywell Rebellion GCI System, 2, (July 2020), <https://www.honeywellprocess.com/library/marketing/notes/Rebellion-Gas-Cloud-Imaging-PIN.pdf>.

<sup>395</sup>*Id.*

<sup>396</sup> 87 FR 74744-74745 (December 6, 2022).

approaches provides a clear pathway for compliance and helps to ensure any approved alternative is rigorous and can achieve equivalent or better reductions.

The commenter (0844-EDF *et al.*) says that as proposed, the advanced monitoring alternative requires annual OGI at all sites, regardless of PTE. This means EPA's proposed alternative is more comprehensive and is likely to achieve greater emission reductions, at least at smaller sites, than the BSER and would apply to many more sites. EPA must ensure that the BSER is no less protective than the alternative and should therefore strengthen the OGI program to remove any disparities in the stringency or coverage of the two potential approaches.<sup>397</sup>

The commenter (0844-EDF *et al.*) believes EPA should allow companies to use advanced monitoring technology as an alternative to OGI only when equivalent emission reductions can be demonstrated across a range of emission distributions. To do so, EPA could establish a framework that includes several pre-approved alternatives reflecting different combinations of detection threshold, frequency, regular OGI inspections, and OGI follow-up requirements. Critically, this framework should center on emission reductions, and need not necessarily reflect technologies or practices that are already “in actual routine use somewhere,”<sup>398</sup> (although many are) so long as they are not “purely theoretical or experimental” or “based on a ‘crystal ball’ inquiry.” As discussed earlier in these comments, CAA is a technology forcing statute,<sup>399</sup> and section 111 “looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present.”<sup>400</sup> EPA could thus design frameworks that accommodate reasonably anticipated improvements in detection capabilities, rather than the limitations of currently in-use technologies. Alongside this preapproved framework, EPA could also consider allowing for submission of alternatives that may have more limited applicability (for instance, in higher emitting basins like the Permian) for specific approval.

The commenter (0844-EDF *et al.*) continues, with available methods for comparing emission reductions across different LDAR approaches, EPA need not foreclose the use of new and existing technologies that can effectively reduce emissions. However, EPA must only allow technologies that can be proven to satisfy rigorous parameters and achieve the same or greater emission reductions under a variety of scenarios. To ensure equivalent emission reductions, EPA could finalize multiple approved alternatives by evaluating monitoring frequency and detection capabilities—meaning that technologies with better detection capabilities could be used less frequently and those with higher detection limits could be used more frequently.

The commenter (0844-EDF *et al.*) states for large emission events detected through screening, operators should be required to immediately report to a publicly-accessible database any detected emissions, and additionally, report when the repair is complete. As EPA has recognized, super-emitters should not occur at well designed and well-maintained sites. Mitigating super-emitters, while extremely important, is the bare-minimum that EPA should seek to achieve through the LDAR program. If a super-emitter is detected, the operator should be required to submit

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<sup>397</sup>See, e.g., OOOOa TSD at 56-57 (comparing Method 21 effectiveness at 500 and 10,000 ppm and finalizing 500 ppm as alternative in order to achieve reductions equal to or greater than OGI BSER).

<sup>398</sup>Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973).

<sup>399</sup>Union Elec. Co. v. EPA, 427 U.S. 246, 257 (1976).

<sup>400</sup>Portland Cement Ass'n, 486 F.2d at 391.

supporting documentation and explain the likely cause. Operators who could prove the emissions resulted from a permissible event, like a scheduled blowdown, would not have to undertake additional action. However, where the cause of the emissions is unknown, or where multiple events have been detected at the same source or from the same operator, EPA should require a full engineering analysis.

Though commenter (0844-EDF *et al.*) supports the alternative framework as set forth by EPA, there are also various other ways in which the LDAR program could be structured within the CAA framework—including layered approaches and advanced monitoring for compliance assurance. Section 114 of the CAA grants EPA authority to require screening with advanced technologies for compliance assurance purposes. Under CAA section 114(a)(3), EPA “may require any person who owns or operates any emission source . . . to install, use, and maintain . . . monitoring equipment” and “may . . . require enhanced monitoring and submission of compliance certifications.” For major sources, EPA is statutorily required to promulgate enhanced compliance assurance monitoring standards,<sup>401</sup> as it has done in the past.<sup>402</sup> Requiring enhanced monitoring for oil and gas sources would be a well-justified use of EPA’s discretion because of the severe and widespread problem of fugitive emissions in this sector. Under this alternate approach, EPA could designate OGI as the BSER for fugitive emissions and require advanced screening at all sites periodically for compliance assurance purposes.

The commenter (0844-EDF *et al.*) states as EPA has recognized, a well-maintained site that is following the work practice standards included in the proposed rulemaking (and as strengthened in the ways described in these comments) should not experience super-emitter events.<sup>403</sup> Nonetheless, these large emission events occur frequently across the industry—including at sites owned by major oil and gas companies.<sup>404</sup> Using advanced methods to periodically screen for super-emitter events would allow EPA to ensure compliance with the underlying work practice standards and could be used to prevent operators experiencing super-emitters from certifying compliance in those instances.

The commenter (0844-EDF *et al.*) notes as a CAA section 114 requirement, advanced monitoring would create further incentives for operators to comply with the work practice standards and take preventative measures against abnormal process emissions. It would also help ensure that reported emissions and inventories are accurate.<sup>405</sup> Furthermore, operators could pool

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<sup>401</sup>42 U.S.C. § 7414(a)(3) (“The Administrator shall in the case of any person which is the owner or operator of a major stationary source, and may, in the case of any other person, require enhanced monitoring and submission of compliance certifications.”).

<sup>402</sup>See, e.g., Compliance Assurance Monitoring, 62 Fed. Reg. 54,900 (Oct. 22, 1997).

<sup>403</sup>See Refinery Standards at 75,190 (explaining that the fenceline monitoring pollutant level that triggered corrective action “was consistent with the emissions projected from fugitive sources compliant with the provisions of the . . . standards”).

<sup>404</sup>See Permian Methane Analysis Project, Operator Emissions, <https://data.permianmap.org/pages/operators> (showing the ten operators with the highest number of detected emissions with emission rates greater than 1000 kg/hr, including ConocoPhillips, BPX, and Occidental).

<sup>405</sup>Refineries RTC at 13 (“The fenceline monitoring approach was proposed largely to address concerns that emissions, particularly from fugitive sources . . . , are difficult to characterize and studies have shown measured emissions to be many times higher than inventory reported values.”).

resources and hire a single LDAR contractor to conduct aerial surveys across an entire basin.<sup>406</sup> This is a low-cost solution (\$100-200/site) for ensuring compliance and allowing for quick detection and mitigation of large emission events. Accordingly, the commenter encourages EPA to consider how the compliance assurance benefits of these technologies may be integrated into EPA's proposal in a manner that helps to further support emission reductions.

Response I-7-174: EPA acknowledges the commenters support for the use of alternative technologies. EPA has taken this comment into account as they designed the alternative technology program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>407</sup> See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative methane detection technologies, including where EPA specifically discussed the goal of incentivizing new technologies, plus requested additional feedback from owners and operators on ways to improve and further incentivize use of alternative technologies.<sup>408</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of alternative technologies for detection of fugitive emissions under the advanced methane detection technology program, and section XI.B.1.b of the preamble to the final rule for a specific discussion on technology flexibility.

Comment: Commenter (0787-Atmos) fully supports the EPA's November 2021 Proposal to allow for bimonthly screening surveys using advanced leak detection technology and annual OGI or EPA Method 21 monitoring at each individual well site or compressor station.<sup>409</sup> In order to maximize the incentives for companies in the natural gas sector to adopt advanced emissions monitoring technology, the commenter recommends that the EPA (1) publish a list of approved technologies that are as good or better than OGI and (2) adopt a matrix approach for monitoring requirements.

Response I-7-175: EPA acknowledges the commenter's support. In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>410</sup>

Comment: Commenter (0934-Leak Surveys, Inc.) argues if an aerial survey triggers a OGI ground survey, as proposed in November 2021, it would be adding additional cost to the site operator. This response penalizes commercial operators and would discourage the site from even considering these advanced technologies.

Response I-7-176: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane

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<sup>406</sup> See, e.g., SPOG Pilot, Methane Emissions Management Program, <https://www.spogab.com/memp-spog-pilot>; Arolytics, Who We Work With: Governments & Regulators, <https://arolytics.com/who-we-work-with/>.

<sup>407</sup> 87 FR 74740-74746 (December 6, 2022).

<sup>408</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>409</sup> Id. at 63,169, 63,175.

<sup>410</sup> 87 FR 74740 (December 6, 2022).

detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>411</sup>

### ***7.2.9 Publish List of Approved Technologies/Alternatives to Approval Process***

Comment: Commenters (0787-Atmos, 0807-BP) suggests that EPA publish a list of approved alternative fugitive emissions monitoring technologies for companies to use.

The commenter (0787-Atmos) says that the NSPS and EG rules should largely retain existing regulations that require companies to submit individual applications to the agency to utilize AMEL.<sup>412</sup> However, AMEL applications can take one to two years before EPA approves them, which delays the implementation of technologies. A published list of approved technologies, with the ability for companies to notify EPA of a new monitoring technology as it becomes available, would help eliminate the innovation barriers embedded in the November 2021 Proposal.

The commenter (0787-Atmos) suggests that for technologies not on EPA's published list, or while EPA gathers the technical expertise to develop such a list, EPA should amend its regulations to allow a notification to the agency that the company has conducted a performance test demonstrating that the AMEL technology exceeds the applicable OGI standard for at least a six-month period. So long as a company submits proof to EPA that the technology is as good or better than OGI, EPA should automatically allow its use for fugitive emissions monitoring at facilities that meet the technology's operating criteria (*e.g.*, line of sight). Note that any equipment that is out of the technology's operating criteria should remain subject to the applicable regulatory fugitive emissions monitoring requirements. Amending and developing the NSPS and EG regulations in this manner would accelerate the adoption of advanced, highly sensitive fugitive emissions monitoring technology and ease the administrative burden EPA would otherwise have to deal with in processing applications.

The commenter (0807-BP) believes EPA should clarify and streamline how operators demonstrate that a technology achieves the emissions detection threshold. Industry needs clear guidance and procedures for how to demonstrate a technology meets the specified emission detection limit. The commenter specifically encourages EPA consider, and take comment on, the potential role that third-party certification organizations and technology vendors can play in the verification process. According to the commenter, EPA already follows this approach in closely related contexts. For example, third-party organizations like the National Physical Laboratory confirm that FLIR OGI cameras can image gas at the required NSPS OOOOa concentration and flow rates. Similarly here, EPA could allow operators to rely on third-party certification organizations and technology vendors to demonstrate that their technology meets the alternative screening standard requirements.

Commenter (0807-BP) adds EPA could streamline the verification process by maintaining a regularly updated list of approved technologies. With only a few proven methane technology vendors in the market today, companies may find themselves duplicating efforts in

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<sup>411</sup> 87 FR 74740 (December 6, 2022).

<sup>412</sup>Id. at 63,166.



demonstrating and verifying compliance. As proposed, each individual operator would have to undertake the process of verifying their advanced screening technology for compliance, even if the technology has already been verified for use by another operator. The commenter states by maintaining a list of approved technologies, EPA could reduce these duplicative efforts and maintain a list, posted on its website, for approved technologies that meet methane detection thresholds. To expedite the use of advanced methane technologies and to make alternative screening more widely available, the commenter recommends that EPA consider pre-verifying existing, proven technologies that meet the standard in advance of the rule's compliance deadlines.

Response I-7-177: See discussion in section IV.B.3 of the December 2022 Supplemental Proposal.<sup>413</sup>

Comment: The commenter (0831-AXPC) states that given the challenges with approving alternative means of emission limitation (AMEL) under section 111(h)(3) of the CAA, the commenter strongly supports EPA's effort to explore other routes that could ease the ability for new technologies to be utilized for compliance.

Response I-7-178: EPA acknowledges the commenter's support.

Comment: Commenter (0749-PAW, 0810-Petroleum Alliance-OK, 0820-Pioneer, 0831-AXPC) note that with the quickly evolving space of emission technologies, a clear path for approved technologies is needed.

The commenter (0810-Petroleum Alliance-OK) says that should simplify the approval process and not delay or hold emerging alternative technologies to higher standards than existing OGI requirements. For this type of technology, as well as continuous monitoring technologies, the commenter encourages EPA to develop a framework that will allow technologies to be used without going through an additional approval process (*e.g.*, specified surveys per year if the technology has a specified detection limit).

The commenters (0820-Pioneer, 0831-AXPC) recommend EPA establish clear and consistent parameters under which a technology will be able to detect methane emissions and site-specific variables can be addressed in conditions required for the use of the technology. The commenters also recommend that EPA should allow for basin-wide equivalency determinations or basin-wide approvals, once equivalency has been demonstrated, and incorporation by reference of emerging technologies to other sites.

The commenter (0820-Pioneer, 0831-AXPC) support the allowance for modeling and testing at a controlled test environment to demonstrate performance of a new technologies. The commenters supports EPA allowing for vendors and manufacturers as applicants for approval of emerging technology and not limiting the submissions to oil and natural gas companies with sites. Artificially limiting submissions to oil and natural gas companies prohibits the experts that are

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<sup>413</sup> 87 FR 74747 (December 6, 2022).

developing these new and emerging technologies from working with EPA and other stakeholders to implement the technologies as broadly as possible to reduce emissions at a lower cost.

The commenter (0749-PAW) adds to promote innovation and ingenuity, any prescriptive language that could limit development of technology should be avoided. Instead, language should be included to allow states to incorporate these technologies.

Response I-7-179: See discussion in section IV.B.3 of the December 2022 Supplemental Proposal.<sup>414</sup>

Comment: Commenter (0747-SENST) believes that EPA should develop a rigorous review process to evaluate screening programs before they are approved and implemented as alternatives to the BSER. The commenter believes that EPA should investigate in detail the role of modeling for informing regulations regarding screening methods and how results can vary by changing model inputs and parameter settings. Further, the use of models to evaluate or approve different programs with screening methods requires further evaluation.

Response I-7-180: See discussion in section IV.B.3 of the December 2022 Supplemental Proposal.<sup>415</sup>

### ***7.2.10 Clarifications/Questions***

Comment: Commenter (0604-Providence) states that the proposed 10 kg/hr threshold was not clearly defined. The commenter asks additional questions such as whether it matters if the 10 kg/hr originates from a single leaking component or whether it is a site-wide emission threshold. The commenter was also unclear whether the advanced measurement technology is required to distinguish between fugitive emissions and emissions from permitted sources. The commenter further asks questions on what follow-up action would be required when a detection is made if the technology does not distinguish between fugitive emissions from a permitted source, and what would be required during the follow-up OGI survey. The commenter questioned the benefit of the alternative program if the alternative screening always triggers a follow-up OGI survey.

Response I-7-181: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for alternative screening using advanced methane detection technologies in the December 2022 Supplemental Proposal. For details, please see the discussion in section IV.B.1 of the December 2022 Supplemental Proposal.<sup>416</sup>

## **7.3 Continuous Monitoring**

### ***7.3.1 General Support/Technology Information***

Comment: Several commenters (0437-NYOSC, 0588-Project Canary, 0590-Honeywell, 0791-Airdar, 0767-Scientific Aviation, 0756-Baker Hughes, 0759-LongPath Technologies, Inc.

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<sup>414</sup> 87 FR 74747 (December 6, 2022).

<sup>415</sup> 87 FR 74747 (December 6, 2022).

<sup>416</sup> 87 FR 74740 (December 6, 2022).

(LongPath) *et al.* are in favor of including continuous monitoring as an alternative to the fugitive emissions monitoring requirements in the rule. The commenters report that continuous monitoring technologies are available and can be cost-effective reliable alternative methods to traditional detection methods.

Commenter (0588-Project Canary) specifically indicates that continuous monitoring systems possess multiple advantages including:

- Detecting methane emissions faster both from the site and specific leak location,
- Capturing intermittent emissions that periodic surveys may not,
- Providing rapid verification of repairs, and
- Collecting additional temporal information that can help in developing future EPA regulations.

Commenter (0588-Project Canary) states their continuous monitoring system has been tested at the Colorado State University METEC, where METEC simulated leaks of various sizes from oil and natural gas production equipment by releasing methane gas at a known rate. Testing has been conducted in multiple seasons, wind conditions, and leak rates. Several rounds of testing have occurred for methane, specifically in February 2021, August 2021, and September 2021. In all cases, leaks have been detected rapidly (within minutes of any release).

Commenter (0590-Honeywell) points out that although methane is the main component of natural gas, a leak may not be pure methane. Monitoring for other gas compounds, in addition to methane, can be another benefit of continuous monitoring technology.

Commenter (0437-NYOSC) believes the rule should take advantage of the expanding availability of cost-effective continuous methane monitoring technology to phase in a continuous methane monitoring requirement, perhaps starting with sites with the potential for large emissions.<sup>417</sup>

Commenter (0759-LongPath *et al.*) states that continuous monitoring must be included in upcoming regulations to keep up with the pace of innovation that has occurred over the last year. The commenter believes that not including continuous monitoring in the regulations would make companies less likely to implement continuous monitoring, and companies who have already invested in continuous monitoring programs will suffer an additional cost burden in comparison to peers using inferior methodologies.

The commenter (0759-LongPath *et al.*) further notes that environmental damage depends on the cumulative amounts of methane, VOC, and other pollutants that enter the atmosphere over time, not the instantaneous rate of emissions. Continuous monitoring is the only way that total pollution can be assessed unambiguously because it measures the duration of emissions events. Relatedly, continuous monitoring enables more rapid mitigation of emissions, such that total

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<sup>417</sup> See: Maamary, Rabih, et al. "A Quantum Cascade Laser-Based Optical Sensor for Continuous Monitoring of Environmental Methane in Dunkirk (France)" *Sensors* 16, no. 2: 224. 2016. See also: Titchener, James et al. "Single Photon Lidar Gas Imagers for Practical and Widespread Continuous Methane Monitoring," *Applied Energy*, Volume 306, Part B, January 15, 2022.

cumulative emissions over time are much lower with continuous monitoring technologies compared with survey technologies.

The commenter (0759-LongPath *et al.*) states continuous monitoring has been extensively evaluated by scientists and engineers at NGOs, academic institutions, and industry through both laboratory and field testing, including controlled releases and validation against Best Available Technology in controlled settings. Additional tests of continuous monitors are being undertaken through the Advancing Development of Emissions Detection (ADED) study.<sup>418</sup> Testing has also been conducted in field settings, both through comparing different measurement techniques<sup>419</sup>, as well as through controlled releases.<sup>420</sup>

The commenter (0759-LongPath *et al.*) notes industry adoption has been growing rapidly. Operators have been active in research projects and industry consortia. For example, the EPA Methane Workshop<sup>421</sup> included producers such as TRP Energy, Jonah Energy, and Occidental Petroleum Corporation. Moreover, numerous companies have publicly announced their adoption of continuous monitoring. In 2021, Southwestern Energy announced its plans to continuously monitor its Appalachia basin operations,<sup>422</sup> and ExxonMobil announced that it had expanded use of continuous monitoring.<sup>423,424</sup> By the end of 2021, 5,000 continuous emission monitoring systems were deployed in North America versus less than 1,000 at beginning of the year.

Response I-7-182: EPA acknowledges the commenters support for the use of continuous monitoring. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>425</sup>

Comment: Commenter (0588-Project Canary) states numerous peer-reviewed studies have demonstrated that emissions from oil and natural gas operations are intermittent.<sup>426</sup> This effect

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<sup>418</sup> C. Bell, Investigating Detection Capabilities of Next Generation Leak Detection Systems under Single Blind Protocol, American Geophysical Union Winter Meeting 2021, GC24D-02, December 14, 2021.

<sup>419</sup> Erin E. Tullios, Sam Aminfar, Felipe J. Cardoso-Saldaña, David Allen, Isabel Mogstad, Langley DeWitt, Bradley Flowers, S.C. Herndon, Anna Scott, S. Elms, B. Smith. "Insights from a Field Trial of Methane Detection Technologies." American Geophysical Union Fall Meeting 2019.

<sup>420</sup> See e.g., Project Astra, University of Texas at Austin. <https://dept.ceer.utexas.edu/ceer/astra/>.

<sup>421</sup> <https://www.epa.gov/system/files/documents/2021-08/epa-methane-detection-virtual-workshop-august-2021-finalagenda.pdf>.

<sup>422</sup> <https://www.businesswire.com/news/home/20210623005910/en/Southwestern-Energy-Signs-Agreement-to-Certify-andContinuously-Monitor-Potential-Emissions-From-All-Appalachia-Production>.

<sup>423</sup> <http://www.scientificaviation.com/major-energy-companies-join-forces-to-battle-methane-emissions/>.

<sup>424</sup> [https://corporate.exxonmobil.com/News/Newsroom/News-releases/2021/0907\\_ExxonMobil-to-certify-natural-gas-helpcustomers-meet-environmental-goals](https://corporate.exxonmobil.com/News/Newsroom/News-releases/2021/0907_ExxonMobil-to-certify-natural-gas-helpcustomers-meet-environmental-goals).

<sup>425</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>426</sup> Allen, David T., Felipe J. Cardoso-Saldaña, and Yosuke Kimura, Variability in spatially and temporally resolved emissions and hydrocarbon source fingerprints for oil and gas sources in shale gas production regions, *Environmental science & technology* 51, no. 20 (2017): 12016-12026; Valeria Di Filippo, Ammar Abdilghanie Mohammed, Jianmin (Jimmy) Zhang, Ashraf El-Messidi, Pejman Kazempoor, Nasr Alkadi, Measurement-Based Emission Factors Using BHGE Advanced Methane Sensing Technologies and Analytics (Mar. 31, 2019), Environment and Climate Change Canada (ECCC) Project GCXE18S024. Technical Report; Cardoso-Saldaña, Felipe J. and David T. Allen, Projecting the Temporal Evolution of Methane Emissions from Oil and Gas Production Sites, *Environmental Science & Technology* 54, no. 22 (2020): 14172-14181; Variability observed over time in methane emissions from abandoned oil and gas wells, *International Journal of Greenhouse Gas Control* 100

may be more pronounced with respect to high emissions events: one study<sup>427</sup> found that high emission events are brief and concluded that “short-term sampling is likely to miss them.” Additionally, the variability in emissions rate is not caused by changes in production rate: one study found that production variability only accounts for 10 percent of the observed variability in emissions rate.<sup>428</sup>

The commenter (0588-Project Canary) states this variability is due to the underlying engineering of an oil and natural gas production site. Intermittent emissions are the most typical type of emissions detected from locations. This is caused by intermittent pressure fluctuations that are constantly being managed at a production facility. Tank levels and pressures rise and fall, separators dump periodically, slugs and flow rate fluctuations from the wells themselves occur, and seal and valve effectiveness can vary with ambient temperature fluctuations and environmental factors.

The commenter’s (0588-Project Canary) data shows that, while one individual day may present a high emissions event, these levels are seldom observed on the following day or days. This data also demonstrates that sampling on any one individual day may mischaracterize the emissions distribution of a given site, a conclusion that is echoed in the peer reviewed studies.<sup>429</sup>

The commenter (0588-Project Canary) adds when an operator is armed with a situational awareness on a continuous basis of when and where emissions are occurring, that operator has a much greater ability to find and fix non-routine/non-allowable emission events. That operator also gains a greater awareness of the types of routine/allowable emission events that it may wish to target for voluntary future emissions reduction projects. Such projects include addition of liquid loadout control systems, well blowdown combustion rather than venting, replacement of higher emitting valves/pneumatics, and chemical programs to prevent waxes/hydrates.

Response I-7-183: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>430</sup>

Comment: Commenters (0588-Project Canary, 0756-Baker Hughes, 0759-LongPath *et al.*, 0791-Airdar) state continuous monitoring can help provide on-the-ground information that the sector currently lacks. This will, among other things, ensure federal and state decisions in this area are made with the best available information. One of the areas of general agreement in the oil and natural gas sector is that, according to multiple studies on the topic, fugitive emissions estimates

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(2020): 103116; Tullos, E. E., Stokes, S. N., Cardoso-Saldaña, F. J., Herndon, S. C., Smith, B. J., and Allen, D. T., Use of Short Duration Measurements to Estimate Methane Emissions at Oil and Gas Production Sites. *Environmental Science & Technology Letters*, 8(6) (2021), 463–467.

<sup>427</sup> Riddick, Stuart N., Denise L. Mauzerall, Michael A. Celia, Mary Kang, and Karl Bandilla, Variability observed over time in methane emissions from abandoned oil and gas wells, *International Journal of Greenhouse Gas Control* 100 (2020): 103-116.

<sup>428</sup> Brantley, Halley L., Eben D. Thoma, William C. Squier, Birnur B. Guven, and David Lyon, Assessment of methane emissions from oil and gas production pads using mobile measurements, *Environmental Science & Technology* 48, no. 24 (2014): 14508-14515.

<sup>429</sup> e.g., Allen, David T., Felipe J. Cardoso-Saldaña, and Yosuke Kimura, Variability in spatially and temporally resolved emissions and hydrocarbon source fingerprints for oil and gas sources in shale gas production regions, *Environmental Science & Technology* 51, no. 20 (2017): 12016-12026.

<sup>430</sup> 87 FR 74744-74745 (December 6, 2022).

have been underestimated.<sup>431</sup> The commenter (0588-Project Canary) believes their view is supported by not only Project Canary's data, but by analysis using outside and independent sources as well. The commenter's analysis, using the FEAST model<sup>432</sup>, an open-source software tool that compares the efficacy of different leak detection programs, demonstrates that using a continuous monitoring program for LDAR with the use of a follow-up OGI camera avoids more than 80 percent of emissions and reduces emissions by more than 2 times compared with bi-annual surveys.

Commenter (0791-Airdar) cites to several studies showing that a small fraction of emission sources comprises the majority of total emissions.<sup>433,434,435,436,437</sup> These studies indicate a significant potential to reduce emissions by resolving a few large leaks. It is important to understand the nature of fugitive emissions to overcome challenges in monitoring emissions and address deficiencies in current methodologies.

The commenter (0588-Project Canary) speculates that continuous monitoring would result in emissions reductions well above those estimated in the November 2021 Proposal, in an amount between about 370 million short tons of methane to about 3,700 million short tons of methane.<sup>438,439</sup> According to EPA, all the requirements from its proposed regulations for new and existing sources together result in a reduction of 41.1 million short tons of methane. Thus, even at the lower bound, if only 12 percent of sources choose to implement continuous monitoring (or

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<sup>431</sup> Miller, Scot M., Steven C. Wofsy, Anna M. Michalak, Eric A. Kort, Arlyn E. Andrews, Sebastien C. Biraud, Edward J. Dlugokencky, et al. Anthropogenic emissions of methane in the United States, *Proceedings of the National Academy of Sciences* 110, no. 50 (2013): 20018-20022; Alvarez, Ramón A., Daniel Zavala-Araiza, David R. Lyon, David T. Allen, Zachary R. Barkley, Adam R. Brandt, Kenneth J. Davis, et al., Assessment of methane emissions from the US oil and gas supply chain, *Science* 361, no. 6398 (2018): 186-188; Chen, Yuanlei, Evan D. Sherwin, Elena SF Berman, Brian B. Jones, Matthew P. Gordon, Erin B. Wetherley, Eric A. Kort, and Adam R. Brandt, Comprehensive aerial survey quantifies high methane emissions from the New Mexico Permian Basin (2021); Zhang, Yuzhong, Ritesh Gautam, Sudhanshu Pandey, Mark Omara, Joannes D. Maasackers, Pankaj Sadavarte, David Lyon, et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, *Science Advances* 6, no. 17 (2020).

<sup>432</sup> Kemp, Chandler E., Arvind P. Ravikumar, and Adam R. Brandt, Comparing natural gas leakage detection technologies using an open-source "virtual gas field" simulator, *Environmental science & technology* 50, no. 8 (2016): 4546-4553.

<sup>433</sup> Daniel Zavala-Araiza et al., "Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites," *Environ. Sci. Technol.* 49, no. 13 (2015): 8167-8174.

<sup>434</sup> Riley M. Duren et al., "California's methane super-emitters," *Nature* 575 (2019): 180-184.

<sup>435</sup> Dennis Prince, "Fugitive Emissions Study," CETAC-West (2005).

<sup>436</sup> Adam R. Brandt, Garvin A. Heath, and Daniel Cooley, "Methane Leaks from Natural Gas Systems Follow Extreme Distributions," *Environ. Sci. Technol.* 50, no. 22 (2016): 12512-12520.

<sup>437</sup> Kelly Vaughn and Matt McGee, "Dozens of "super-emitting" oil and gas facilities leaked methane pollution in Permian Basin for years on end," accessed January 26, 2022, <https://carbonmapper.org/dozens-of-super-emitting-oil-and-gas-facilities-leaked-methane-pollution-in-permian-basin-for-years-on-end/>.

<sup>438</sup> For convenience, we provide calculations with respect to methane emission reductions. CM offers similar reductions for VOC as well.

<sup>439</sup> As stated previously, this assumes that EPA approves the use of CM as an alternative compliance standard for meeting the requirements for OOOOb and OOOOc and that all sources choose to comply using that method. We are also assuming that repair occurs within the same timeframe regardless of the detection device, so there would be no difference in emissions reductions when comparing the various alternatives with respect to detection (i.e., we do not assume that detection to repair is Y number of days for CM and detection to repair is Z number of days for periodic OGI).

if all sources so chose but total leaks were only 12 percent of those estimated), that would double the methane reductions from the regulation.

The commenter (0759-LongPath *et al.*) provides another example, consider a super-emitting event that emits methane at a rate of 100 kg/hr. Most continuous monitoring solutions would detect this event and notify the operator within an hour, leading to immediate response. If continuous monitoring was not used and the event continued until the next operator rounds, several days or weeks could pass until identified. If the issue was not identified until the next quarterly LDAR inspection, up to 3 months could pass. The commenter indicates that based on the estimated response times, continuous monitoring could achieve a 99.5 percent reduction in methane emissions compared to only 75.3 percent under quarterly LDAR (assuming worst case scenario for detection timelines).

The commenter (0759-LongPath *et al.*) also notes that analysis using FEAST<sup>440</sup> demonstrates that using a continuous monitoring program for LDAR with the use of a follow-up handheld OGI inspection avoids more than 80 percent of emissions and reduces emissions by more than two times compared with bi-annual surveys.

The commenters (0588-Project Canary, 0759-LongPath *et al.*) give an example, if a site had a 10 kg/hr emission rate or higher, OGI, flyovers, drones, and/or satellites could detect this. A continuous monitor would pick up a 10 kg/hr emission within seconds, whereas other technologies would detect this when they were active or aimed directly at the emissions source. The commenter (0588-Project Canary) states instead of only two to six measurements per year, continuous monitoring systems provide hundreds to millions of measurements per year. The commenter (0759-LongPath *et al.*) gives the example of a continuous monitor detecting a single, constant emissions event of 10 kg/h within hours -instead of within an average of 30 days for bi-monthly inspection-based screening (such as airborne detection) -results in incremental reduction of 7.2 tons of methane (30 days x 24 hr x 10 kg/hr). At a social cost of methane of \$1,800 per ton the Incremental emission reduction provides \$12,960 in climate benefits beyond the reductions accomplished by bi-monthly inspection-based screening.

The commenter (0588-Project Canary) adds continuous monitoring also has a clear advantage in detecting small emission events, due to continuous monitoring's sensitivity and continuous functioning. By contrast, flyovers and satellites cannot detect very small emission sources at a given location. OGI cameras may be able to find smaller leaks, but given the periodic nature of OGI inspections, they will always result in fewer emissions avoided than continuous monitoring. Intermittent emissions are inherently difficult to detect with non-continuous systems.

Response I-7-184: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>441</sup>

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<sup>440</sup> Kemp, Chandler E., Arvind P. Ravikumar, and Adam R. Brandt. "Comparing natural gas leakage detection technologies using an open-source "virtual gas field" simulator." *Environmental science & technology* 50, no. 8 (2016): 4546-4553.

<sup>441</sup> 87 FR 74744-74745 (December 6, 2022).

Comment: Commenters (0588-Project Canary, 0756-Baker Hughes, 0759-LongPath *et al.*, 0791-Airdar, 0844-EDF *et al.*) state continuous monitoring provides more accurate quantification of emissions than those offered by periodic surveys. Emission rates may not be constant and can vary due to many factors including changing weather conditions, facility operations, third-party activities, and the time of day. Periodic surveys using EPA Method 21 or handheld OGI cameras are unable to capture the variability of emissions over time.

The commenter (0759-LongPath *et al.*) states numerous studies have demonstrated that a significant fraction of both small and large emission sources – including super-emitters – are intermittent.<sup>442,443,444,445,446</sup> Additionally, the variability in emissions rate is not caused only by changes in production rate. One study found that production variability explains only 10 percent of the observed variability in the emissions rate<sup>447</sup>, meaning that production rates are not generally the cause of this variability.

The commenter (0759-LongPath *et al.*) states intermittent emitters are potentially missed by systems that are employed only a few times per year because survey visits may not intersect with the time at which an emission occurs<sup>448</sup>. In order to improve the efficiency and effectiveness of methane emission control rules, EPA needs to better understand the temporal variability of emissions. These data can only be provided by continuous monitoring systems. Indeed, the ability to assess intermittent vs. sustained emissions profiles is a unique strength of continuous monitoring that cannot be provided by survey technologies. Continuous monitoring systems are the most likely to capture intermittent emitters and assess their importance.

The commenter (0791-Airdar) notes that five separate inspections were performed over the 18-months using an OGI camera and a hi-flow sampler to quantify emissions. When compared to emission rates obtained by the continuous monitoring system, the values agreed. However, there are times emission rates are high, which is not captured by the periodic surveys. The average emission rate measured by continuous measurements were five to seven times larger than the average emission rate determined through periodic monitoring. This shows how emissions may be underestimated through periodic methods and are less accurate in determining the exact

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<sup>442</sup> Allen, David T., Felipe J. Cardoso-Saldaña, and Yosuke Kimura. "Variability in spatially and temporally resolved emissions and hydrocarbon source fingerprints for oil and gas sources in shale gas production regions." *Environmental Science & Technology* 51, no. 20 (2017): 12016-12026.

<sup>443</sup> Valeria Di Filippo, Ammar Abdilghanie Mohammed, Jianmin (Jimmy) Zhang, Ashraf El-Messidi, Pejman Kazempoor, Nasr Alkadi. "Measurement-Based Emission Factors Using BHGE [Baker Hughes] Advanced Methane Sensing Technologies and Analytics," March 31, 2019, Environment and Climate Change Canada (ECCC) Project GCXE18S024. Technical Report.

<sup>444</sup> Cardoso-Saldaña, Felipe J., and David T. Allen. "Projecting the Temporal Evolution of Methane Emissions from Oil and Gas Production Sites." *Environmental Science & Technology* 54, no. 22 (2020): 14172-14181.

<sup>445</sup> Stuart N. Riddick, Denise L. Mauzerall, Michael A. Celia, Mary Kang, Karl Bandilla, "Variability observed over time in methane emissions from abandoned oil and gas wells." *International Journal of Greenhouse Gas Control* 100 (2020): 103116.

<sup>446</sup> Tullos, E. E., Stokes, S. N., Cardoso-Saldaña, F. J., Herndon, S. C., Smith, B. J., & Allen, D. T. (2021). Use of Short Duration Measurements to Estimate Methane Emissions at Oil and Gas Production Sites. *Environmental Science & Technology Letters*, 8(6), 463–467. doi:10.1021/acs.estlett.1c00239.

<sup>447</sup> H.L. Brantley, et al., "Assessment of methane emissions from oil and gas production pads using mobile measurements." *Environmental Science & Technology* 48, no. 24 (2014): 14508-14515.

<sup>448</sup> T.L. Vaughn, et al., "Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region", <https://www.pnas.org/content/115/46/11712.abstract>.



impact of a leak on the environment. Continuous monitoring technologies are better at capturing intermittent emission than any other method. All other methods currently available today including airplanes, drones, vehicles, and handheld gas detectors provide only periodic screening for emissions.

The commenter (0791-Airdar) states the effectiveness of continuous monitoring systems has been demonstrated by industry and eagerness is growing to adopt continuous monitoring technologies. Since 2005, the commenter has worked with industry to conduct several projects that have demonstrated the capabilities of our continuous monitoring system and has seen support from industry since that time for continuous monitoring technologies. In 2009, the commenter won an Alberta Science and Technology Award (ASTECH) with several letters of recommendation from industry showing their support for Airdar.

The commenter (0791-Airdar) states while most of their projects are confidential, projects that can be shared publicly include our work at three oil and gas facilities<sup>449,450,451</sup>, a wastewater treatment plant<sup>452</sup>, and a composting facility. The work completed at the wastewater treatment plant was presented at the 2019 Air Quality Measurements and Technology Conference sponsored by the Air and Waste Management Association (AWMA). This project also won an award from the Consulting Engineers of Alberta. In 2010, the commenter worked with an industry group who saw the value and capabilities of Airdar to develop a GHG offset protocol in Alberta that would see GHG credit be awarded for reduction in fugitive methane emissions that were authenticated by Airdar or a similar continuous monitoring technology.<sup>453</sup> This moved to the final stage of approval but was not approved in the end. The proposed protocol would have generated GHG credits worth much more than the cost of the Airdar monitoring, which the industry group saw as a way for paying the extra monitoring efforts in addition to performing the required LDAR surveys.

Commenters (0588-Project Canary, 0844-EDF *et al.*) states many continuous monitoring systems already meet the parameters EPA has outlined for advanced monitoring: they screen sites at least six times per year at a 10 kg/hr detection threshold. In fact, many screen sites far more often than the bimonthly minimum required and have greater detection capabilities. Because of this, EPA can develop an alternative framework for continuous monitoring by making adjustments to account for some of the differences and potential concerns EPA has outlined with respect to continuous monitoring. EPA may need to develop separate, detailed work practice follow-up requirements for continuous monitoring that are technology-specific, similar to the proposed Appendix K for OGI.<sup>454</sup>

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<sup>449</sup> Dennis Prince, “Field Trial of the Airdar Technology at the Facility XX Gas Plant,” PTAC (2007): <https://www.ptac.org/airdar-technology-field-trial/>.

<sup>450</sup> Dennis Prince et al., 2010.

<sup>451</sup> Dennis Prince et al., 2019.

<sup>452</sup> Dennis Prince et al., 2019.

<sup>453</sup> Dennis Prince et al., 2010.

<sup>454</sup> See, e.g., Comment from Kuva Systems, Teledyne FLIR, CleanConnect.AI, Honeywell Rebellion (Proposed Alternative Work Practice for C-OGI).

The commenter (0588-Project Canary) believes continuous monitoring meets the statutory requirements for a work practice standard.<sup>455</sup> Continuous monitoring has been demonstrated as an effective method of assisting companies in reducing their emissions. It has no non-air quality health and environmental impacts. And its energy requirements are minimal because continuous monitoring systems operate on solar panels and/or small, internally located batteries. The commenter urges EPA in its forthcoming supplemental proposal to solicit public comment on whether continuous monitoring is appropriate for inclusion as an alternative compliance mechanism in the final rule. And when it finalizes this proposed rule, EPA should expressly allow sources to use continuous monitoring as an AWP standard to comply with the requirements contained in that final rule.

The commenter (0844-EDF *et al.*) is aware that the capabilities of continuous monitors (as well as other advanced screening technologies) are rapidly improving, and so the commenter encourages EPA to create incentives within its framework that will encourage operators to deploy continuous monitors and other advanced technologies in a manner that is maximally protective, consistent with these technological advances. For instance, the agency might consider how approaches that exceed its required standards have implications for community monitoring, subpart W reporting, and potentially other related areas.

The commenter (0791-Airdar) adds that detection and monitoring of fugitive emissions is a challenge due to their intermittent and stochastic nature. Currently, LDAR surveys of equipment components using EPA Method 21 or handheld OGI cameras are required a few times a year. The infrequency at which these surveys are performed allows super-emitting events to go undetected for a while before they are discovered, prolonging the impact of these emissions on the environment. An emission event that occurs in-between inspections may go undetected for several days or weeks. The current proposed rule requires LDAR inspections to be performed quarterly, meaning that it may be up to 3 months before the leak is discovered. Continuous monitoring technologies provide 24/7 monitoring of a facility, allowing super-emitting sources to be detected quickly and repairs to be made in a timely manner.

The commenter (0791-Airdar) notes that specific components are regulated and must be included in an LDAR monitoring program. Components classified as unsafe or difficult-to-monitor are not included in these programs and are not monitored in an LDAR survey. However, through Airdar's experiences, some leaks do not occur at these regulated components or expected locations. In a case study at a midstream oil and gas facility<sup>456</sup>, the commenter found a large methane leak coming from a vent located 1.2 m off the top of the compressor building, which was supposed to be blowing pure air. Instead, the vent was releasing 4 percent air and 96 percent total hydrocarbons of which 94 percent was methane. Such a vent would not have been included in a traditional LDAR program. A survey of the compressor building with handheld detectors

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<sup>455</sup> Specifically, CAA Section 111(h)(1) authorizes the administrator to promulgate work practice standards that reflect "technological system[s] of continuous emission reduction . . . taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements."

<sup>456</sup> Dennis Prince et al., "Remote Detection and Quantification of Fugitive Emission Sources Using Ambient Measurements," in 2010 Air and Waste Management Association Annual Conference Online Proceedings (Calgary, AB, 2010).

had previously been completed, but technicians were unable to detect and locate the leak, resulting in this leak going undetected.

The commenter (0791-Airdar) adds that handheld gas detectors or OGI cameras must be aimed directly at a specific component to detect a leak. This can be labor intensive for the technician and introduces confirmation bias into the monitoring. Confirmation bias in an emission monitoring setting occurs when an assumption to the location or timing of the emission source is made, and monitoring activities are then focused on these assumptions. The possibility of emission sources or events at other locations and times are not considered. Continuous monitoring systems like Airdar that can intercept and detect plumes at low concentrations remotely do not suffer from confirmation bias and do not miss important sources. Surveillance can be provided over a great area, enabling monitoring of emission sources both on- and off-site without the need to aim an instrument directly at the emission source.

Commenters (0756-Baker Hughes, 0791-Airdar) state accurate quantification provided by continuous monitoring can determine the relative importance of emissions, helping operators to prioritize work and direct resources to the right problem. This was seen in a project at a steam assisted drainage (SAGD) facility where high levels of hydrogen sulfide were being detected.<sup>457</sup> This facility was under pressure from the regulator to address the problem. Several potential sources were identified, including a hot lime softening (HLS) system that was known to emit hydrogen sulfide. An intervention to tie the HLS system was being considered, but it was a costly solution. The facility wanted to make sure the HLS system was the main problem contributing to hydrogen sulfide emissions before moving ahead with the intervention.

The commenter (0791-Airdar) installed a continuous monitoring system measuring hydrogen sulfide and total hydrocarbons (THC). It found that the HLS system was not the main cause of the issue and that the tanks on site were the largest emitters. A significant off-site source was also found and was one that was not previously identified. This information allowed operations to perform interventions at their tank farm, which dramatically reduced hydrogen sulfide and THC emissions, saving the facility from performing a costly intervention. Quantification of emissions before and after an intervention based on a real observation of the emissions and not an estimate based off a point measurement allowed for the effectiveness of the intervention to be evaluated. This case study demonstrates that continuous monitoring enables quick verification of any repairs, allows operators to be confident in the interventions made, and ensure that resources were directed to the right problem.

Commenter's (0791-Airdar) approach using concentration measurements and wind data (speed and direction) collected continuously and used to locate and quantify emission sources has been tested in several field trials. This method has been tested in a controlled release study performed in 2008. Details of this study are publicly available in U.S. Patent 8,510,059.<sup>458</sup> This control study describes the quantification of a controlled release of natural gas, obtained by breaking a

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<sup>457</sup> Dennis Prince et al., "Cost Reduction of Leak Detection and Fence Line Monitoring Activities Through Automation," in 2019 Air Quality Measurement Methods and Technology Conference Proceedings (Durham, NC, 2019).

<sup>458</sup> Dennis Prince, Method and System for Measuring Emission and Quantifying Emission Source, U.S. Patent 8,510,059, filed April 14, 2009 and issued August 13, 2013.

visualized emission plume into small elements, calculating the flux of the compound for each element, and summing up elements that are determined to be within the boundaries of the plume. The control study showed that emission rates obtained through the Airdar system were within 10 percent of the actual values under ideal conditions where background levels of the compound measured was stable and when measurements are taken at several heights. Continuous monitoring technologies are capable of providing an accurate quantification of emissions. Accuracy in emissions quantification is important to knowing the extent of emissions and track progress in remediation efforts.

The commenter (0780-LongPath Technologies, Inc. (LongPath)) states methane emissions from oil and gas are intermittent and vary through time, at both producing and abandoned well sites<sup>459,460</sup>, with intermittent emissions contributing substantially to overall emissions. Continuous monitoring is therefore unparalleled in the value it provides. Snapshot monitoring approaches (OGI, aircraft, satellite surveys) cannot provide adequate information for operators to mitigate intermittent emissions. Continuous monitors can mitigate intermittent emissions by revealing temporal context about deviations from baseline rates, which can be linked with SCADA data for root cause analysis. Off-site diagnosis and even repair can be accomplished. Further, continuous monitors don't mistake intermittent emissions for persistent emissions, as can be the case for snapshot-in-time surveys, resulting in wasted OGI follow-ups.

The commenter (0780-LongPath) states the temporal context and coverage provided by continuous monitors also means that leak repairs can be immediately verified. LongPath has found linked leaks that it took more than one attempt to repair – without continuous monitoring, the first repair would not have mitigated all emissions, and the operator wouldn't have known that other problems persisted.

Commenter (0780-LongPath) states LDAR-Sim model results<sup>461</sup> show expected emissions given a LongPath emissions mitigation program, a quarterly LDAR program (with efficacy matching Zimmerle *et al.*<sup>462</sup>) and no LDAR program. Interestingly, in this simulation, a super-emitter event occurs just following an OGI visit. While this would seem to be a rare event, commenter (0780-LongPath) has documented occurrences of this scenario in customer monitoring. In periods of both normal operations and during a fugitive event, LongPath's overall emissions reductions are substantially better than quarterly OGI.

Response I-7-185: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>463</sup>

Comment: Commenter (0831-AXPC) argues EPA's framework should support the use of continuous monitoring technologies. While continuous monitoring technologies may not lend themselves specifically to a sample matrix, EPA should establish simple and effective

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<sup>459</sup> Johnson and Heltzel, "On the Long-Term Temporal Variations in Methane Emissions from an Unconventional Natural Gas Well Site."

<sup>460</sup> Riddick et al., "Variability Observed over Time in Methane Emissions from Abandoned Oil and Gas Wells."

<sup>461</sup> Modeling Provided by Highwood Emissions Management, January 2022.

<sup>462</sup> Zimmerle et al., "Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions."

<sup>463</sup> 87 FR 74744-74745 (December 6, 2022).

requirements for the use of continuous monitoring technologies in a similar manner suitable to the parameters for continuous monitoring technologies.

The commenter (0780-LongPath) also supports a matrix of AWP's with dimensions of survey frequency and effective detection threshold. Requirements for root cause or OGI follow-ups, repair validation, regional applicability, and sensor validation checks would be specified for each area of the matrix. Whether in matrix form or in a simple survey vs. continuous monitor form, commenter (0780-LongPath) defines the following critical elements for high-frequency (continuous) monitoring AWP:

- OGI should not be a required follow-up for every emission detected by continuous monitors.
- The continuous monitor should be used for verification of leak repair.
- Operators should be able to use continuous monitors on a site-by-site basis instead of mandating that one type of screening be broadly applied across geographic areas.
- Daily verification checks should not be required of continuous monitors.

Response I-7-186: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>464</sup>

Comment: Commenter (0780-LongPath) states the industry is already using continuous monitoring. The commenter alone is providing continuous monitoring coverage across more than 120,000 acres of oil and gas operations in the DJ, Anadarko, Delaware and Midland basins. The operators the commenter monitors would like the regulations to recognize their use of this gold standard of monitoring by allowing them to eliminate duplicate spending on relatively less effective OGI surveys for compliance. Most importantly, local communities, the environment, and the climate need the fastest and most effective solutions to be employed for reducing methane emissions from oil and gas.

This year, commenter (0780-LongPath) was awarded the highly competitive ARPA-E SCALEUP funding,<sup>465</sup> an indicator of the federal government's firm belief and investment in LongPath's continuous monitoring as an enduring solution for mitigating methane emissions from oil and gas. The commenter has demonstrated the reliability of the system for accurately detecting and quantifying methane emissions, including intermittent emissions<sup>466,467</sup> in extensive third-party blind testing at the METEC facility.<sup>468</sup> LongPath's proven dynamic range for continuous methane monitoring includes both very small emission rates (2000 kg/hr), for example from fugitive events caught and mitigated on natural gas production sites.

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<sup>464</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>465</sup> Website at: <https://arpa-e.energy.gov/news-and-media/press-releases/doe-announces-additional-47-million-fundingcommercial-scaling>.

<sup>466</sup> Alden et al., "Single-Blind Quantification of Natural Gas Leaks from 1 Km Distance Using Frequency Combs."

<sup>467</sup> Coburn et al., "Long Distance Continuous Methane Emissions Monitoring with Dual Frequency Comb Spectroscopy: deployment and blind testing in complex emissions scenarios."

<sup>468</sup> Website at: <https://energy.colostate.edu/metec/>.

Response I-7-187: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>469</sup>

Comment: Commenter (0588-Project Canary) states that multiple operators first started implementing different continuous monitoring systems over two years ago. There have been several key learnings in the implementation process that can assist in the development of performance-based standards. In addition, the commenter is providing an example of an SOP that has been used as a template for multiple different operators.<sup>470</sup> Within the commenter's attachment they provide a detailed operation summary of their continuous monitoring system including the selection of the monitoring technology, monitor factor calibration and set-up, siting, the initial 60-day period, and their operations 60 days and beyond.

Response I-7-188: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>471</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the requirement to provide the standard operating procedures that apply to continuous monitoring technologies seeking ATM approval.

### ***7.3.2 Technology-Neutral/Matrix Approach***

Comment: Commenter (0588-Project Canary, 0590-Honeywell, 0756-Baker Hughes, 0760-Airdar *et al.*, 0780-LongPath) believes, along with other stakeholders, that the final rule should be technology neutral. All technology types should be acceptable, provided they can demonstrate sufficient effectiveness in detecting and measuring methane emissions, as determined by the rule, and if they are validated in third-party blind testing under expected operating conditions. If continuous monitoring is pushed into the AMEL process, the protracted application and approval processes will disincentivize operators from using this highest standard of monitoring and will not allow the most radical emissions reductions to occur.

The commenter (0588-Project Canary) adds QA/QC requirements should be determined by the sensor manufacturer. These more detailed requirements could be built out over time by EPA. But, given the variety of technologies that meet continuous monitoring, it would be premature at this time for EPA to promulgate specific QA/QC requirements. Overly prescriptive requirements at this stage in the development of new and promising technology may stifle the full emergence of that technology.

The commenter (0590-Honeywell) believes that EPA's continuous monitoring framework should be outcome and performance-based, rather than prescriptive, thereby enabling operators to choose the technology and system design best suited to achieve the specified performance for their facility. Such an approach would focus on detecting leaks at a certain leak rate and frequency of monitoring to achieve the specified level of performance. The commenter suggests a 10 kg/hr minimum detection threshold with daily readings coupled with an annual OGI survey

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<sup>469</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>470</sup> See Appendix B of the commenter's letter.

<sup>471</sup> 87 FR 74744-74745 (December 6, 2022).

as an initial approach for continuous monitoring systems. EPA should establish a regulatory framework that allows the Agency to easily increase the level of required performance in leak detection as the pace of innovation accelerates and continuous monitoring technologies continue to improve and become increasingly cost-effective over time. An outcome-based approach would also allow operators flexibility to choose one technology, such as a particular continuous monitoring solution, or to choose a combination of technologies if the performance objectives are satisfied. EPA should also consider incentives that reward greater emission reductions that exceed minimum requirements at the same or lower cost.

Commenter (0756-Baker Hughes) states that a fit-for-purpose framework supports the efforts of maintaining flexibility for multiple technologies. Performance can be defined as the number of emission events and the cumulative total of emissions that are detected and subsequently repaired. Multiple technologies exist capable of high-performance emission reduction that have already been widely accepted in industry separate from regulatory influence. Continuous monitoring is one of these technologies, potentially offering the most comprehensive performance capabilities and should be seen as an option in the new framework.

The commenter (0760-Airdar *et al.*) supports the expansion of the 10 kg/hr detection limit into a matrix-based approach. The matrix solution could be designed to achieve the same emission reduction as a 10 kg/hr limit and bi-monthly screening. Dimensions of this matrix would include 1) a technology's minimum effective detection threshold, and 2) a technology's detection (*i.e.*, "survey") frequency.

The commenter (0780-LongPath) states operators should be able to use continuous monitors on a site-by-site basis instead of mandating that one type of screening be broadly applied across geographic areas. Operators should be given the flexibility to "mix and match" the use of continuous monitors and other BSER for regulatory compliance across the same geographic region. Additionally, daily verification checks should not be required of continuous monitors. Quality control metrics are built into continuous monitoring systems. Submitted fugitive emission monitoring plans should outline QA/QC steps and validation with third-party testing.

The commenter (0780-LongPath) endorses the use of a matrix that would allow for equivalent overall emissions reductions by specifying trade-offs between frequency of screening and the size of emission requiring action (leak definition). The commenter provides an example of such a matrix shown below, in which, for more rapid screening frequencies, a larger leak definition is allowable (leak definition and, interchangeably, minimum effective detection threshold, see definitions below).

| Screening Frequency | Effective Threshold of Detection | Leak Definition           |
|---------------------|----------------------------------|---------------------------|
| Monthly             | 10 kg/hr                         | 10 kg/hr (same as left)   |
| Bi-Weekly           | >10 kg/hr                        | >10 kg/hr (same as left)  |
| Weekly              | >>10 kg/hr                       | >>10 kg/hr (same as left) |

Commenter (0780-LongPath) also recommends that if continuous monitoring downtime exceeds an EPA defined reasonable percentage, then EPA require that BSER require supplement

measurements. For example, the commenter recommends that if sensor malfunctions for a continuous monitor exceed 3 months (one quarter) then quarterly OGI BSER should be initiated to supplement lost fugitive emissions monitoring coverage.

The commenter (0780-LongPath) notes that continuous monitor downtime can occur due to a variety of factors, such as sensor malfunction, communications failures, or inability to operate due to extreme conditions (environmental conditions that are outside of what is expected for the operating environment). The commenter contends that it is important to differentiate between downtime due to shortcomings of the continuous monitor itself from downtime due to external factors (for example, extreme weather events). For each category, the commenter recommends that EPA define reasonable percentages of downtime to be expected during the normal course of operation.

Commenter (0760-Airdar *et al.*) agrees with EPA that a single AWP is not suited for continuous monitoring technologies, and instead propose that continuous monitoring be regulated as a separate AWP based on the same concepts or as part of a matrix of alternatives.

The commenter (0760-Airdar *et al.*) indicates that continuous monitors provide several advantages for emissions detection, particularly for the fast detection of large emissions and intermittent emissions that are widely observed. Indeed, continuous monitoring is an established modality that is highly effective in reducing methane and VOC emissions from oil and gas infrastructure. Among alternative and traditional monitoring techniques, continuous monitoring is uniquely suited to provide information about intermittent emissions. This modality can be used not only to identify and prioritize problematic emissions, but to verify if and when emissions reductions occur following repair. Continuous monitoring can detect fugitive emissions many times faster than survey technologies (including BESR), with consequent multi-factor reductions in overall cumulative emissions to the atmosphere from a given fugitive event. The costs of continuous monitors are comparable to quarterly OGI and bimonthly surveys, with differences offset by the gas loss savings of finding emissions faster and not missing or misinterpreting intermittent events. Finally, industry adoption of this methane monitoring strategy is widespread, with field data demonstrating its efficacy.

The commenter (0760-Airdar *et al.*) notes that continuous monitors comprise a broad class of sensors covering many styles of monitoring, including the following five different styles:

1. Networks of point sensors (*e.g.*, Baker Hughes, Project Canary, Qube, and Sensirion),
2. Individual point sensors (*e.g.*, Aeris and Quanta3),
3. Shared point sensors (*e.g.*, Project Astra),
4. Open path laser sensors (*e.g.*, LongPath Technologies and Mirico)
5. OGI Camera sensors (*e.g.*, CleanConnect.AI, Honeywell, and Kuva Systems).

Commenter (0760-Airdar *et al.*) states in order to provide for technology neutral regulation, this diversity of continuous monitors must be considered in any regulation that covers continuous monitors. All these solutions have the potential to detect the same or more emissions than inspection-based screening solutions such as airborne detections plus annual OGI. For some items relevant to the regulation of continuous monitors—such as the number of monitors on a site



and the minimum response factor to methane—values for each style of continuous monitor are intended to be different and may be measured in different units. For other items—such as the minimum detection level—values should be consistent across all styles of continuous monitors and should correspond to values for other types of screening solutions. The commenter suggests that the latter elements form the basis for a common Continuous Monitoring Framework as part of an AWP, and that the former elements be required for inclusion in a given operator or owner’s fugitive emissions monitoring plan.

Response I-7-189: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>472</sup>

Comment: Commenter (0756-Baker Hughes) believes continuous monitoring should be viewed as equivalent to OGI-based solutions. There exist various validation methods, either controlled release testing or periodic field calibration or “bump tests” to verify system performance. Because it is not necessary to conduct OGI confirmation upon notification of every detection event, removing this requirement would mitigate the concern that continuous monitoring is cost prohibitive. In short, the commenter encourages EPA to expeditiously develop and deploy the proposed framework for advanced measurement technologies that monitor sites continuously.

Response I-7-190: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>473</sup>

Comment: Commenter (0807-BP) discourages comparing continuous monitoring to OGI technology, as such a comparison cannot do justice to the fundamental paradigm shift represented by, and the significant methane leak detection and mitigation potential of, continuous monitoring. An attempt to narrowly compare the two technologies risks undermining the potential of continuous monitoring to help reduce emissions. The commenter recognizes continuous monitoring must demonstrate equivalent or greater emissions reductions compared to OGI, but that comparison should focus on the emission reduction results achieved by both technologies, *i.e.*, a performance-based comparison, rather than a comparison based on the supposed similarities of these different approaches.

The commenter (0807-BP) recognizes that continuous methane monitoring is vastly different from the low-frequency, handheld analyzers and cameras historically relied on by industry and regulators alike.

Response I-7-191: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>474</sup>

### ***7.3.3 Specific Technologies***

Comment: Commenter (0762-CleanConnect.AI *et al.*) states continuous OGI cameras (C-OGI) are an established class of continuous monitoring technologies for methane and VOC emissions;

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<sup>472</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>473</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>474</sup> 87 FR 74744-74745 (December 6, 2022).

other classes of continuous monitoring include non-visual solutions based on point sensors, open path detectors and scanning laser towers. C-OGI cameras are closely related or exactly like the cameras used for handheld OGI inspections in that they are based on infrared imaging technology engineered to detect and visualize emissions based on absorption characteristics of specific compounds, generally methane and VOCs. Multiple types of C-OGI cameras are commercially available from several solution providers and they are being successfully operated by several dozen oil and gas operators at several hundred sites for the detection of fugitive emissions, vents, and operational upsets.

The commenter (0762-CleanConnect.AI *et al.*) states the key feature of C-OGI cameras is the provision of images of emissions at or near their source—similar to the images provided by handheld OGI inspections. Moreover, C-OGI cameras operate continuously, generate consistent, automated emission detections and create a record of emission events or absence of emissions. The commenter reports a number of benefits associated with C-OGI cameras, including:

- a. Continuous operation to detect emission events and intermittent emissions quickly which enables faster repair.
- b. Ability to pinpoint by remote visual inspection what component or equipment is leaking and to determine if an emission event is resulting from a normal, allowable emission (for example compressor methane slip), or by abnormal operation, nuisance events or leaks.
- c. Provides follow clearly defined, transparent and standardized procedures on how to react to a detected emission event before sending personnel to the event site.
- d. Enables the collection of time-series data for individual emission sources which provide insights about the behavior of the emission (intermittent, persistent, rising, or falling).
- e. Provides consistency in detection.
- f. Repair validation by visual inspection without the expense of a site visit.
- g. Continuous quantification of leak rate or concentration.
- h. Because C-OGI is image based, it can be regulated using the same concepts used for handheld OGI inspections, especially the concepts of an “operating envelope” as well as clearly defined criteria for what steps are to be taken upon detection of emissions.

The commenter (0762-CleanConnect.AI *et al.*) finds for the example of a C-OGI camera detecting a single, constant emissions event of 10 kg/hr within hours—instead of within an average of 30 days for bi-monthly inspection-based screening (such as airborne detection) - results in incremental reduction of 7.2 tons of methane (30 days x 24h x 10 kg/hr). At a social cost of Methane of \$1,800 per ton the incremental emission reduction provides \$12,960 in climate benefits beyond the reductions accomplished by bi-monthly inspection-based screening when assuming the same speed of repair.

The commenter (0762-CleanConnect.AI *et al.*) states the key differences of the proposed C-OGI AWP compared to EPA’s proposed screening protocol are the following four aspects:

1. Instead of the requirement for handheld OGI follow-up on detected emissions during screening, C-OGI is utilized for root-cause analysis and repair planning.
2. Instead of requiring handheld OGI to validate repairs, C-OGI images are utilized for repair validation.

3. Instead of mandatory use of one type of screening across a county or region, Operators are permitted to use C-OGI on a site-by-site basis and other screening methods or quarterly handheld OGI inspections elsewhere.
4. Removal of daily verification check requirement as the C-OGI technology will be developed based on operating envelopes and is connected to a data platform for quality control.

Response I-7-192: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>475</sup>

Comment: Commenter (0762-CleanConnect.AI *et al.*) agrees with EPA that the proposed screening with advanced measurement technologies approach is not suited for mentioned continuous monitoring technologies, sensor networks or open-path technology, and emphasize that C-OGI has been proven as a technology that would be separate to the specific inspection-based screening technologies referenced in the proposed regulation. As such, the commenter instead proposes that C-OGI cameras be regulated as a separate AWP, however based on the same “screening” concept.

Response I-7-193: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>476</sup>

Comment: Commenters (0944-Kuva Systems (Kuva), 0780-Longpath) provided cost information for their particular continuous monitoring solutions.

Commenter (0944-Kuva) reports that their camera solution is available commercially today. The commenter has provided the current price and cost of ownership for operators as confidential business information (CBI). The price of the solution is expected to fall if EPA were to mandate or to incentivize large scale deployment. The commenter expects to be able to increase manufacturing capacity to meet very large-scale demand (tens of thousands of cameras per year) with a 9-month lead time, and large-scale demand (thousands of cameras per year) with a shorter lead time.

Commenter (0780-LongPath) also submitted detailed cost information for their continuous monitoring as CBI by mail. The commenter points out that it is critical to recognize the efforts of operators who are paying for both continuous monitoring and for LDAR compliance inspections with OGI. It is unreasonable for these operators, who are voluntarily using the highest standard of continuous monitoring, to be required to also pay for regular OGI surveys simply because regulations have not yet kept pace with technological advancements. The commenter reports that according to a potential customer the current rules are discouraging operators from using alternative technologies and emission reduction goals would be met a lot faster if continuous monitoring is permitted to meet the industry’s LDAR requirements.

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<sup>475</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>476</sup> 87 FR 74744-74745 (December 6, 2022).

Response I-7-194: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>477</sup>

Comment: Commenter (0756-Baker Hughes) offers the LUMEN Sky, UAV-based OGI technology, capable of approximately 6 scfh, or 0.12 kg/hr minimum quantification detection. The combination of high-resolution OGI technology and low-altitude drone flights provides the ability for quantification of emissions down to this low level. This detection limit can be inherently difficult for alternative aerial inspections that use OGI technology from higher altitudes or, conversely, low-altitude drone flights using alternative detection technologies such as non-dispersive “sniffing” sensors or LiDAR. The commenter states LUMEN Terrain, continuous monitoring, is capable of approximately 20 scfh, or 0.43 kg/hr minimum quantification detection.

Response I-7-195: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>478</sup>

Comment: Commenter (0756-Baker Hughes) adds their LUMEN Terrain continuous monitoring system is pre-programmed with process equipment and operational data allowing the platform’s analytics to identify and locate the source of the emission and trigger alerts pursuant to thresholds set during user configuration. For optimum detection and quantification performance, LUMEN Terrain utilizes a proprietary “Sensor Placement Optimization Tool” or SPOT. This uses AI and computer vision to analyze satellite imagery of a potential site. The commenter identifies and classifies assets and components on site, prioritizing likely emission leak sources over normal process venting sources.

The commenter (0756-Baker Hughes) then uses historical weather data, primarily wind speeds and directions to locate the optimum positioning of detection nodes. This allows operators to measure and account for planned releases while allowing the operator to also screen for and assess the severity of unplanned releases. With this technology, operators using continuous monitoring devices can cost effectively deploy resources to repair leaks while also generating a comprehensive picture of a site’s emissions.

Response I-7-196: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>479</sup>

Comment: Commenter (0590-Honeywell) states potential leak locations that are further apart or subject to obstructions may require more devices or cameras. Sometimes, a single monitor can achieve a particular leak rate detection threshold, but other times a site needs multiple monitors to achieve the same leak rate detection threshold. Generally, for C-OGI systems, the capability of detecting leak size is dependent on the distance the leak is from the system. For a C-OGI system, the number of monitors for a given site factor in the size of the site and ensure all monitored equipment is within the specified distance for its target leak size.

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<sup>477</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>478</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>479</sup> 87 FR 74744-74745 (December 6, 2022).

Response I-7-197: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>480</sup>

Comment: Commenter (0604-Providence) indicates that one technology that is not mentioned in the November 2021 Proposal, but that has the ability to overcome the shortcoming of aforementioned continuous monitoring systems is autonomous and continuous OGI systems. ExxonMobil and the commenter jointly developed such a technology about a decade ago,<sup>481</sup> which uses an OGI camera connected to a computer with plume recognition algorithms to identify leaks and alert operators. It has some of the same benefits of an OGI leak survey but on a continuous basis, effectively combining the advanced screening and follow-up OGI survey into a single system. It can pinpoint the leak location and separate the fugitive emissions from other sources. The system developed jointly by ExxonMobil and Providence has not been widely used primarily due to the high cost of OGI cameras as the core component of the system. Recently Teledyne FLIR has made a methane focused, uncooled, and less expensive OGI camera commercially available. With the lower cost of the OGI camera core, the commenter is developing a new autonomous/continuous leak detection and alarm system which is undergoing field testing. If successful, such a system should be considered an advanced measurement system that would not need an OGI follow-up if a large leak is detected. The commenter encourages the EPA to structure the rule with the possibility of such a technology in mind so the regulations will be progressive in adopting future technologies. Specifically, the commenter is suggesting that if the continuous monitoring system is OGI based, a follow-up OGI survey to locate the leak is not required because the system has already located the leak.

Response I-7-198: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>482</sup>

Comment: Commenter (0807-BP) believes continuous monitoring can provide a rapid, cost-competitive and autonomous alert system to notify operators of potentially anomalous, unplanned or fugitive emissions events. As an alert system, continuous monitors can trigger additional action to assess conditions and determine the appropriate course of action, including deployment of personnel for further investigation and repair.

Response I-7-199: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>483</sup>

### **7.3.4 General Framework Recommendations**

Comment: Commenters (0767-Scientific Aviation *et al.*, 0780-LongPath) express support for incorporating continuous monitoring under an alternative methane detection technology

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<sup>480</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>481</sup> H.M. Abdel-Moati, J.M. Morris, Y. Ruan, Y. Zeng (2013), “Remote Gas Detection System Using Infrared Camera Technology and Sophisticated Gas Plume Detection Computer Algorithm”. Paper presented at the SPE the SPE Annual Technical Conference and Exhibition, New Orleans, September 30th – October 2nd. Also see Exhibit 2.

<sup>482</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>483</sup> 87 FR 74744-74745 (December 6, 2022).

framework and provide specific recommendations to the elements EPA proposed for a framework and requested comment on.

Commenter (0767-Scientific Aviation *et al.*) fully supports the development of a framework for advanced technologies that monitor sites continuously. Certain emission sources tend to be unpredictable, some of which can be large. Frequent, recurrent inspections result in discovery of those large (and a number of moderate and some small) emission sources sooner, thereby reducing total emissions. Since manual inspections tend to be episodic and resource intensive, continuous monitors have been developed to provide these frequent, recurrent inspections automatically, thereby detecting emission events more quickly than would occur under manual methods.

The commenter (0767-Scientific Aviation *et al.*) notes that EPA correctly identifies that continuous technology requires a different framework than that proposed for episodic screening technologies. EPA notes that triggering OGI surveys too frequently would disincentivize the use of continuous monitoring systems. The commenter believes that this is a risk for disincentivizing the use of episodic screening technologies as well. An annual component level OGI survey is sufficient to identify and mitigate small leaks that are missed by alternative technologies with higher detection limits. The scientific literature<sup>484,485,486</sup> has shown that a small number of large sources constitute the majority of total emissions from leaks and other malfunctions. Accordingly, the majority of these emissions (the target of the more frequent surveys) are addressable by both screening and continuous monitoring technologies. Therefore, an OGI survey should not be required more than annually when alternative monitoring technologies are deployed, even under the screening options.

The commenter (0767-Scientific Aviation *et al.*) states that a fundamental difference in modality between episodic and continuous technologies is that a continuous technology is in position to confirm the reduction in emissions associated with an emission source repair much more rapidly than even the most frequent OGI schedule could deliver.

The commenter (0767-Scientific Aviation *et al.*) provides in their comment letter a number of recommendations in response to the elements EPA proposed for a framework and requested comment on. The commenter provides in their letter comment on the context of equivalency to quarterly OGI inspections and leveraging these systems to speed discovery of large emissions sources. Key features of the commenters letter ask that operators should develop site specific monitoring plans and continuous monitoring alerting criteria should result in an analysis to identify the source and take corrective action considering the following. The commenter additionally provides detailed recommendations on the following:

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<sup>484</sup>Zavala-Araiza, D., Alvarez, R., Lyon, D. et al. Super-emitters in natural gas infrastructure are caused by abnormal process conditions. *Nat Commun* 8, 14012 (2017). <https://doi.org/10.1038/ncomms14012>.

<sup>485</sup>Adam P. Pacsi, Tom Ferrara, Kailin Schwan, Paul Tupper, Miriam Lev-On, Reid Smith, Karin Ritter; Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. *Elementa: Science of the Anthropocene* 1 January 2019; 7 29. doi: <https://doi.org/10.1525/elementa>.

<sup>486</sup>Adam R. Brandt, Garvin A. Heath, and Daniel Cooley *Environmental Science & Technology* 2016 SO (22), 12512-12520 DOI: 10.1021/acs.est.6b04303.

- The number of monitors needed and the placement of the monitors.
- Minimum response factor to methane/ Minimum detection level.
- Frequency of data readings.
- Interpretation of the monitor data to determine what emissions are a detection versus baseline emissions / How to determine allowable emissions versus leaks.
- Meteorological data criteria/ Measurement systems data quality indicators/ Calibration requirements and frequency of calibration checks.
- How to handle situations where the source of emissions cannot be identified even when the monitor registers a leak.
- Approach to determining equivalency to BSER.

Commenter (0780-LongPath) states that continuous monitors are uniquely suited to provide information on the sustained versus intermittent nature of emissions. If the rule is not written correctly to acknowledge the strengths of continuous monitoring systems, requiring OGI follow-up of all emissions (regardless of type, duration, or size) identified by continuous monitors could disincentivize their use.

The commenter (0780-LongPath) says that the first concern (regardless of type) applies to all survey monitors. It will be incumbent upon the owner or operator to interpret the survey or continuous monitor data to determine root cause and corrective action. Indeed, continuous monitors provide a strong advantage over snapshot-in-time approaches, because the size and temporal context of emissions can drive more effective off-site root cause investigation (and even repair). For the second concern (regardless of duration), the commenter views this as a critical part of the follow-up protocols that will leverage the unique strengths of continuous monitoring. For the third concern (regardless of size), the commenter believes it is critically important that the EPA create leak definitions with units of emission rate (not concentration) and that data readings be required in the same units of emission rate (not concentration). With those criteria in place, alerts will only be triggered for emissions that exceed the leak definition.

First, commenter (0780-LongPath) considers the issue of intermittency. In addition to information about the size of the emission (leak definition), continuous monitors can provide information about the “intermittency” or “continuity” of the emission. To avoid putting an undue burden on operators who choose to employ continuous monitors, commenter (0780-LongPath) recommends that these different types of emissions (“intermittent” vs. “continuous”) require different sets of follow-up actions. Further, the commenter recommends that in either case (intermittent or continuous), off-site and, if needed, on-site root cause analyses be allowed before OGI, and that, in the case of intermittent emissions, OGI follow-up not be required at all.

Commenter (0780-LongPath) states the intermittency of emissions, to guide follow-up, could be defined in one of several ways:

- Intermittency could be defined based on peer-reviewed bottom-up modeling studies.<sup>487</sup>

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<sup>487</sup> Vaughn et al., “Temporal Variability Largely Explains Top-down/Bottom-up Difference in Methane Emission Estimates from a Natural Gas Production Region.”

- Intermittency could be defined based on available field-level studies employing continuous monitors (however, given that this data is private, little has been published).
- Intermittency could be defined based on expert knowledge. For example, many operators state that an event exceeding a sustained (*e.g.*, present in 80 percent or more of readings) duration of 24 hours is highly unlikely to be due to planned on-site operations.

Commenter (0780-LongPath) recommends the third option (expert knowledge) as a starting point.

Response I-7-200: See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on advanced methane detection technologies using alternative continuous monitoring systems.<sup>488</sup> The EPA proposed a specific framework for the use of alternative continuous monitoring systems in the December 2022 Supplemental Proposal based on comments received on the November 2021 Proposal. The EPA is finalizing the use of alternative continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program. See section X.B of the preamble to the final rule which details EPA's final standards. The final rule specifies the required elements that must be included in the request for ATM approval of alternative continuous monitoring where this alternative technology will be used to demonstrate compliance.

Comment: Commenters (0807-BP, 0932-GHGSat, Inc.) state that continuous monitoring system has the potential to detect fugitive methane emissions at a materially higher frequency than any traditional, handheld device deployed on a semiannual or quarterly schedule. While a significant upside of the technology—more visibility than previously possible—it also presents some unique challenges, particularly as it relates to sending personnel to the field to address potential emission events. EPA, in consultation with representatives from industry, technology vendors, academia, and civil society, should develop a guideline for program plans prepared and maintained by operators for their continuous monitoring systems.

The commenter (0807-BP) believes EPA should leverage precedent and existing requirements for fugitive emissions monitoring plans in NSPS OOOOa to document continuous monitoring systems. The commenter believes the responsibility should continue to be on operators to prepare and maintain these plans, with the plans available for inspection upon request to EPA. At a minimum, the commenter thinks a transparent continuous monitoring program plan would include: (1) the number of sensors deployed; (2) type of sensor; (3) sensor placement; (4) justification for how the system delivers on the performance standard defined by EPA; (5) description of maintenance plan and procedures; and (6) downtime contingency procedures, including plan and recordkeeping if defaulting to OGI surveys or an advanced screening technology.

The commenter (0585-KOGA) agrees a general monitoring plan in place of a site-specific monitoring plan for each inspection to be performed. Site-specific maps increase administrative costs without a reduction in emissions. A general operating procedure is capable of

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<sup>488</sup> 87 FR 74741-74745 (December 6, 2022).



accomplishing the same objective without the need to create and maintain site-specific monitoring plans.

Response I-7-201: See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on advanced methane detection technologies, including alternative periodic screening and alternative continuous monitoring systems.<sup>489</sup> Please also see section X.B of the preamble to the final rule which details EPA's final standards related to the use of alternative periodic screening and alternative continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program. The final rule specifies the elements the fugitive emissions monitoring plan must contain where alternative technologies will be used to demonstrate compliance and the elements required to be included in the request for ATM approval.

### ***7.3.5 Follow-Up Survey***

Comment: Commenters (0588-Project Canary, 0759-LongPath *et al.*) note continuous monitoring systems provide an advantage over all other types of inspections because they can almost immediately provide evidence of the leak being repaired. Not only can continuous monitoring systems identify the leak faster, but continuous monitoring systems can also identify faster whether the fix was effective (as the continuous monitoring system would immediately register no leak instead of needing to wait for another periodic test). Continuous monitoring systems also show the longer-term effectiveness of the repair by continuously showing that a leak is not detected after the repair occurs. This is different than OGI. With OGI, the repair can be verified immediately upon service, but whether the repair is effective over a longer duration cannot be determined. Even a subsequent OGI inspection may or may not detect an emission event if the event is intermittent.

The commenter (0588-Project Canary) adds rapid leak verification is also a service provided automatically by Project Canary's software. Currently, this is implemented by ensuring that a level falls back below a given threshold (*e.g.*, 20 ppm) for a set period of time.

Response I-7-202: EPA acknowledges the commenters support for the use of continuous monitoring. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>490</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program.

Comment: Commenters (0588-Project Canary, 0807-BP, 0844-EDF *et al.*, 0780-LongPath) argue the continuous monitor should be used for verification of leak repair. Continuous monitors can demonstrate whether emission rates have gone down or returned to baseline conditions following repair. This strength should be leveraged in the AWP for verification of repair, rather

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<sup>489</sup> 87 FR 74741-74745 (December 6, 2022).

<sup>490</sup> 87 FR 74744-74745 (December 6, 2022).

than forcing operators to employ overlapping methods and thereby incur unnecessary costs by using other technologies to validate repair.

The commenter (0844-EDF *et al.*) states under this approach, the detection limit of the continuous monitoring technology would need to be lower than 10 kg/hr, but not necessarily as low as OGI. The equivalent detection limit for estimated with FEAST or other similar approaches by modeling it as a very high-frequency discrete screening. The operator would need to continuously model the expected emission rate to determine when there are excess emissions, and operators would have a set time to repair detected excess emissions.

The commenters (0844-EDF *et al.*, 0780-LongPath) state, with continuous monitoring solutions, the follow-up work practices are extremely important. It is critical to clearly define which emissions will require follow-up and which will not. Otherwise, there is a significant risk that operators will be alerted to emissions but determine they do not need to be fixed or cannot be fixed. This problem also exists with other LDAR approaches, but is more pronounced with continuous monitoring where emissions will be more frequently detected. With the potential to be alerted to a wide variety of emission events, absent rigorous protocols, operators may be more likely to avoid following up on each event and will be incentivized to view it as part of normal operations to avoid OGI follow-up costs. EPA must therefore very clearly define the events that require inspection and repair. This might be done by clearly defining the range of the site's baseline emissions. Above the range, there would be a presumption of an abnormality and, unless the operator could prove with records that it resulted from a permissible event, the operator would be required to conduct a ground survey and repair.

The commenter (0780-LongPath) adds after a leak is detected, a root cause analysis is the most logical first step in assessing emissions information from continuous monitors. Importantly, continuous monitors also monitor intermittent emissions. Follow up on intermittent emissions with an OGI camera has low odds of coinciding with the presence of the intermittent event and therefore has low odds of success. Therefore, intermittent emissions should not require OGI follow up at all.

Response I-7-203: EPA acknowledges the commenters recommendations related to the use of continuous monitoring for follow-up identification and verification of leaks being repaired. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>491</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program. This includes details on the investigative analysis that is required when action levels have been exceeded. A follow-up survey using OGI is not required under these circumstances.

Comment: Commenters (0590-Honeywell, 0760-Airdar *et al.*, 0780-LongPath) provide recommendations on requiring annual OGI surveys in combination with continuous monitoring.

Commenter (0590-Honeywell) recommends EPA initially require an annual OGI survey after installation of a continuous monitoring system, and as more data are received from continuous

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<sup>491</sup> 87 FR 74744-74745 (December 6, 2022).

monitoring systems demonstrating effectiveness, the period between OGI surveys may be reduced and possibly eliminated.

Commenter (0760-Airdar *et al.*) believes that EPA's November 2021 Proposal for continuous monitoring should exist in combination with OGI inspections. For continuous monitors that demonstrate that equivalent OGI products are part of the continuous monitoring data, the commenter believes this requirement can be waived. The commenter suggests that OGI surveys remain a requirement on some cadence, for example, annual. The commenter suggests that any OGI survey that takes place as part of an emission follow-up or other on-site activity counts toward this requirement, such that the clock is "reset." In addition, the commenter is also in support of a required cadence of OGI surveys that is a function of other capabilities of continuous monitors. For example, less frequent OGI surveys might be required for technologies with lower (more sensitive) detection limits. Further, the frequency of OGI surveys could be adjusted in the future using demonstration data.

Commenter (0780-LongPath) suggests that it is reasonable for EPA to require annual OGI surveys to accompany continuous monitoring, with the clock restarting upon any OGI follow-up survey that might occur in the course of the year. The commenter believes this requirement is justifiable if the leak definition is to be set at a value as high as 10 kg/hr. If thresholds for follow-up are not based on specific emission rate numbers but rather on changes from baseline emissions, then OGI surveys should be completed during any periods that baseline emission rates are established (to ensure that poor operating conditions are not allowed to be defined as baseline emissions).

Commenter (0780-LongPath) states regions of the matrix with higher sensitivity to emissions (lower detection threshold and leak definition), or higher frequency of readings (faster refresh rate), and/or higher percent site coverage could have less stringent requirements for additional OGI.

Commenter (0780-LongPath) states in a matrix approach, regions of the matrix with higher frequency monitoring (*e.g.*, continuous monitoring) could employ alternative monitoring for verification of repair, whereas regions of the matrix with less frequent monitoring or less sensitive detection thresholds would require OGI. The commenter has documented important examples of OGI-based repairs providing incomplete or insufficient emissions reductions.

The commenter (0780-LongPath) offers an additional consideration on repair validation. Continuous monitors provide temporally ongoing information about emissions, including the onset of problematic emissions and their resolution following repair. Therefore, continuous monitoring solutions should be used to validate repair success without also requiring separate OGI inspection. Requiring OGI follow-up for repair validation would unfairly burden owners and operators by doubling up on costs of overlapping monitoring methods.

The commenter (0780-LongPath) has documented important examples of OGI-based repairs providing incomplete or insufficient emissions reductions. The commenter describes an example of where heightened emissions prompted on-site repair. Despite OGI identification and mitigation of one leak, high emissions persisted. A follow-up OGI visit identified a separate leak,

which was repaired. When emissions still were not reduced to baseline levels, a third and final OGI visit identified four additional small leaks, which were repaired. Following this last repair, the commenter indicates that the site finally returned to baseline emission rates and was considered to be repaired. Snapshot approaches such as OGI or aircraft surveys would not be capable of providing the necessary “eyes on” to ensure that all leaks were identified and repaired.

Response I-7-204: EPA acknowledges the comments on requiring annual OGI surveys in combination with continuous monitoring. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>492</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the investigative analysis that is required when action levels have been exceeded.

### ***7.3.6 Specific Recommendations***

#### ***7.3.6.1 Definitions***

Comment: Commenters (0780-LongPath, 0807-BP) provide relevant suggested definitions to be used under the continuous monitoring framework. The various definitions recommended by commenters follow below.

Commenter (0780-LongPath) states many continuous monitors are capable of accurately detecting and quantifying emissions well below a 10 kg/hr threshold (*e.g.*, LongPath Technologies’ threshold of detection is greater than 50 times below that level.) It is therefore important for a continuous monitoring framework to define not only the effective minimum threshold of detection but also the leak definition (see definitions for both below). Functionally, the requirements for these values can be the same (*e.g.*, 10 kg/hr), but for reasons of clarity, the commenter suggests the inclusion of both terms.

*Minimum Effective Detection Threshold:* the minimum emission rate value that must be detectable by a sensor under any envelope of operating conditions, and with “effective” coverage of all important equipment on-site.

*Leak Definition:* an emission rate that requires action to mitigate. In the proposed AWP, this value is functionally equivalent to the minimum effective detection threshold, given that in the EPA proposed rules, anything above the detection threshold requires action. LongPath Technologies, for example, has a minimum detection threshold of 0.2 kg/hr, but under the proposed AWP would not alert operators to emissions requiring attention until a 10 kg/hr or larger leak were detected.

*Minimum Effective Detection Threshold (units kg/hr):* the minimum emission rate value that must be detectable by a sensor under any envelope of operating conditions, and with “effective” coverage of all important equipment on-site.

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<sup>492</sup> 87 FR 74744-74745 (December 6, 2022).

*Data Reading (units kg/hr):* a “data reading” could be considered to be an individual datapoint readout from an individual sensor (e.g., methane sensor, wind sensor, temperature sensor), or a “data reading” could be considered to constitute a unit of detection or quantification of emission rates from monitored pads. For response to EPA’s question, the commenter speaks to both elements, but define data reading as the latter (an emission rate reading). A “data reading” should not be defined as the readout from a given sensor, such as a concentration or wind value. It is important that EPA ask technology providers to differentiate between sensor readouts (which can be as frequent as many Hz) and data readings, which require aggregation of data from various sensors and some averaging time through turbulent atmospheric conditions (and are therefore less frequent in time than sensor readouts).

The commenter (0780-LongPath) suggests, as a starting point, that EPA use 10 kg/hr for the minimum effective detection threshold and related leak definition, as proposed for the survey AWP.

Commenter (0780-LongPath) offers the following definitions for clarity before describing the AWP follow up procedures:

*Continuous Emission:* an emission that is observed to be present [tbd] percent or more of the observable time over a period of [tbd] hours or longer.

*Intermittent Emission:* an emission that is observed to be present less than [tbd] percent of the observable time over a period of [tbd] hours or longer.

*Detected Emission:* an emission rate (units kg/hr) recorded over any period of time that exceeds the defined leak definition (emission rate in units kg/hr) set by the EPA.

*Alarm Candidate:* when a detected emission exceeds the leak definition (which will be equal to the minimum detection threshold), then an alarm candidate is generated.

*Continuous Alarm-Candidate:* generated for a detected emission that is a continuous emission.

*Intermittent Alarm-Candidate:* generated for a detected emission that is an intermittent emission.

*Emission Event:* an alarm-candidate that requires initiation of follow-up mitigation procedures (e.g., root cause and, if unsuccessful, OGI).

Commenter (0807-BP) states that since there is not a common definition of continuous monitoring, EPA should propose a new definition that provides clarity on what falls within this classification and is sufficiently broad to be agnostic as to specific technologies and approaches. The definition of continuous monitoring should reflect both the intended use case for such a solution, as well as the inherent temporality of the system’s readings—most “continuous”

monitors do not, in actuality, take continuous readings. Instead, they may activate and take readings several times per day, multiple times per hour, or potentially several times per minute.

Commenter (0807-BP) recognizes that there may be diverse views on the use case for continuous monitors and thus the most appropriate definition. EPA might consider convening a series of workshops with stakeholders from industry, academia and civil society to capture these views and ultimately inform the definition EPA proposes for public comment.

Response I-7-205: The EPA acknowledges recommendations for various definitions to incorporate into the continuous monitoring framework. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>493</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including definitions and all requirements that apply to continuous monitoring.

#### 7.3.6.2 Number and Placement of Monitors

Comment: Several commenters (0588-Project Canary, 0756-Baker Hughes, 0760-Airdar *et al.*, 0791-Airdar, 0780-LongPath, 0844-EDF *et al.*) indicate that the effectiveness of continuous monitors is dependent on a number of different factors.

Commenter (0588-Project Canary) adds that continuous monitors can detect the area of the site leaking using the triangulation of continuous monitoring sensors and Gaussian plume models. Continuous monitoring systems achieve this because they contain meteorological systems that communicate wind speed and wind direction to the sensors dashboard. This allows for the use of GIS overlays of the site, which in turn allows the use of ML to help continuous monitoring systems determine the approximate source of the emission. The GIS-based analysis can pinpoint the equipment type that is leaking. This leak source identification process can eliminate or reduce the need to conduct a full OGI survey, because the approximate source of the leak is already identified.

The commenter (0588-Project Canary) states flyover and satellite-based systems do not have sufficient resolution to specifically pinpoint the source of the leak. These systems only inform the operator of a leak on the location at a point in time; operators using those systems then need to be follow up with an OGI inspection to find and fix the leak. Of note, continuous monitors can additionally determine if emissions are coming from off-site sources using the same triangulation method. By contrast, flyovers and satellites simply provide a large heat map showing where emissions are coming from in a more general sense. Thus, continuous monitors allow for a more directed site inspection to find and fix the emission source faster than other methods and mitigate the need for unnecessary OGI inspections that are based on off-site sources.

Commenter (0756-Baker Hughes) states performance of continuous monitoring system, and consequently the number of sensors, is variable and depends on the size of the site, level of congestion, type of components, emission sources, and weather. The commenter's Terrain

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<sup>493</sup> 87 FR 74744-74745 (December 6, 2022).

system analyzes site characteristics in combination with weather to determine the optimum number of sensors for maximum performance.

Commenter (0760-Airdar *et al.*) states OGI cameras that operate in the thermal region of the infrared spectrum (above 3  $\mu\text{m}$ ) are impacted by the  $\Delta T$  between gas and background. To take account of these parameters for OGI inspections, EPA is introducing the concept of an “operating envelope” (see Section 8.4 of Appendix K). Commenters are proposing to utilize the same concept of an operating envelope for determining the placement and number of continuous monitors required to cover a specific site.

The commenter (0760-Airdar *et al.*) states the operating envelope should specify a minimum leak rate detection level, a maximum distance and a range of environmental conditions. The 10 kg/hr minimum leak rate detection level is described throughout the comment to be consistent with EPA’s November 2021 Proposal of 10 kg/hr for bimonthly survey. The required number of monitors per site has to be chosen such that all (or a certain percentage of) relevant pieces of equipment on the site are covered. Fugitive emissions monitoring plans will cover demonstration (and third-party validation testing) of operating envelopes being met.

The commenter (0760-Airdar *et al.*) states an important parameter that impacts absolute emission reductions is the portion of equipment that is covered with a detection limit lower than 10 kg/hr. A sensor placement where the majority of equipment is within for example a 5 kg/hr detection limit and one piece of equipment is covered only at a 15 kg/hr detection limit is preferable over a placement where all components are just within a 10 kg/hr limit. Operating envelopes can be simulated with, for example, atmospheric modeling, or demonstrated in empirical settings.

Commenters (0780-LongPath, 0791-Airdar) note overall site emission rates can be measured with a relatively small number of properly placed sensors. For example, a small wellsite may only need one or two sensors to continuously monitor and quantify emissions. For larger facilities, several monitors may be needed around the fence line of the facility, and some positioned at heights to isolate key pieces of equipment. If the focus of the monitoring is to locate small and medium sized individual sources that are spaced close together, more sensors placed throughout the facility may be needed to isolate small plumes that blend together and become difficult to separate when observed from the fence line.

The commenters (0780-LongPath, 0791-Airdar, 0844-EDF *et al.*) state the placement of monitors is dependent on the focus of the monitoring program. Overall site monitoring requires the sensors to be placed at a distance from potential sources, such as on the fence line with some installed at varying heights. This arrangement will be able to measure the overall site emission rate and locations of the large sources. Commenters (0780-LongPath, 0791-Airdar, 0844-EDF *et al.*) add if pinpointing the location of small to medium sized leaks is the focus of a monitoring program, the sensors need to be placed closer to the potential sources and positioned such that smaller, similar sized plumes can be isolated from each other. This will allow individual smaller sources to be located and quantified.

The commenters (0780-LongPath, 0844-EDF *et al.*) note EPA can create a model for determining proper sensor placement, as it has for refineries fenceline monitoring. In most cases,

the commenter anticipates sensors would be placed close to the largest emission sources, but EPA should also ensure any equipment located farther away can be reliably screened. At larger sites, and depending on technology, this may require multiple sensors to ensure adequate coverage. By contrast, tower-based solutions may be able to reliably screen multiple sites with a single sensor. Sensors must not only be within a horizontal range of emission sources, but must also be able to detect all emission sources vertically.

The commenter (0791-Airdar) states continuous monitoring systems can provide source location to within approximately 3 to 6 meters using sensors positioned roughly 150 meters away. To provide a precise location for the leak to operators, follow-up with a handheld detector or OGI camera is used to pinpoint the exact leak location. Depending on the facility, continuous monitoring systems are able to pinpoint and confirm the exact leak location, making follow-up in the field not necessary. The commenter has observed through several of their projects that continuous monitoring has the potential to satisfy both LDAR and fence line monitoring requirements.<sup>494</sup> The placement of the monitors on the fence line of the facility can allow continuous monitoring of the fence line and LDAR monitoring to take place concurrently.

Commenters (0791-Airdar, 0780-LongPath) state the effectiveness of any methane sensing technology is subject to the distance from sensor to emission source, size of the facility, density of components at the facility, detection limit of the sensor, and micrometeorological and other environmental conditions.

Response I-7-206: The EPA acknowledges the commenters' remarks regarding the effectiveness of any methane sensing technology. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>495</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the operational downtime requirements that apply to continuous monitoring.

#### 7.3.6.3 Minimum Response Factor

Comment: Commenter (0791-Airdar) states the minimum detection level of the sensors or monitors should be below the background level of the compound of interest to have the ability to identify plumes from sources at great distances. Sensors with higher detection limits can still identify sources but only at closer ranges. Sensors with detection limits below the ambient background level of the compound can see large sources at several kilometer ranges. For methane, a detection limit below background level of approximately 1.9 ppm<sup>496</sup> is needed. The stability of the sensor output is also important as this will determine how often calibrations are needed.

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<sup>494</sup> Dennis Prince et al., 2019.

<sup>495</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>496</sup> Ed Dlugokencky, "Trends in Atmospheric Methane," NOAA/GML, accessed January 26, 2022, [gml.noaa.gov/ccgg/trends\\_ch4/](https://gml.noaa.gov/ccgg/trends_ch4/).



The commenters (0590-Honeywell, 0791-Airdar.) state that documenting the baseline over a period of normal operations helps identify anomalies attributed to emission events. For continuous monitoring systems, a specific set of criteria is encoded into the algorithm to determine if the detected emissions are an “alarm” or not. For example, C-OGI systems allow alarms to be assigned to a piece of equipment within a field-of-view based on the concentration of gas detected, duration of the emissions, and the number of detections from the field-of-view over a preset time interval within the daily monitoring period. For a C-OGI system, alarms are accompanied with an image or video for review by operators for final confirmation.

Response I-7-207: The EPA acknowledges the commenters’ input. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>497</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including all requirements that apply to continuous monitoring.

Comment: Commenters (0760-Airdar *et al.*, 0791-Airdar) provide feedback in response to EPA’s request for information related to minimum response factors to methane.

Commenter (0760-Airdar *et al.*) indicates that continuous monitors typically detect methane concentration (measured in units like ppm) or path-integrated methane concentration (measured in units like ppm-m). However, concentration targets, alone, are less meaningful than emission rate targets. Concentration values alone are subject not only to emission rates, but also to meteorological and micrometeorological conditions, sensor distance from the source, inbound plumes from emissions on neighboring sites, rapid fluctuations in ambient or “background” concentrations, and other factors that can severely complicate interpretation. Given that most technologies now offer emission rate metrics (*i.e.*, quantification), it is time for EPA to recast rules in terms of the metric that matters to the Agency, that is, gas emitted to the atmosphere (and not local, distance-dependent and temporally ephemeral concentration enhancements). The commenter therefore recommends replacing “Minimum response factor to methane” with “Emission rate detection threshold.”

Commenter (0760-Airdar *et al.*) suggests, as a starting point, an emission rate detection threshold of 10 kg/hr, if the continuous monitor is expected to work only once every two months. That is, if a matrix were to define gradations of sensitivity alongside gradations of survey frequency, the commenter would recommend, as a starting point, equivalency to the Optional BSER for bimonthly surveys with a threshold of 10 kg/hr. If the continuous monitor is expected to work more frequently, the 10 kg/hr threshold could, for example, be increased to acknowledge faster find-and-fix timelines afforded by higher frequency monitoring. On a sensor-by-sensor basis, the minimum response factor to methane will remain an important element for inclusion into the fugitive emissions monitoring plan submitted by any owner or operator seeking to use alternative monitoring methods.

Commenter (0791-Airdar) states a continuous sensor measuring methane that is responsive enough to distinguish 0.1 ppm above the 1.9 ppm ambient background concentration should be

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<sup>497</sup> 87 FR 74744-74745 (December 6, 2022).

able to detect a source releasing 6 L/min (approximately 0.26 kg/hr) methane at 150 meters distance. In the commenter's control study published in their patent<sup>498</sup>, a 6 L/min source located 60 meters from the monitor (a less sensitive Photovac microFID) was quantified. This demonstrated that the system could measure a methane leak to within 10 percent to 20 percent of the actual emission rate at a range of 60 meters. This is more than enough to meet the 10 kg/hr leak detection limit of other intermittent leak detection approaches which have been approved by the EPA.

The commenter's (0791-Airdar) sensors that are less responsive can still be used in a continuous monitoring system, but the sensor may need to be placed closer to potential sources. These sensors may only be able to detect larger sources. Monitoring of small sources at great distances can best be achieved using sensors with a good response factor. Continuous monitoring systems use many different sensors depending on the compounds being measured. For methane, the commenter deploys a system that can detect and quantify methane sources of 0.26 kg/hr at a range of 60 m away from the source and can detect larger sources even further away.

Response I-7-208: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>499</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including all requirements that apply to continuous monitoring.

Comment: Commenter (0588-Project Canary) recommends using an alert system, similar to their own, to best determine which events require an OGI survey. The four alerts are described below and additional details are provided in the commenter's letter:

- Alert Type 1 – High concentration event as defined by the company (typically greater than 10 ppm methane above background concentration) over a short period of time (about less than one hour) or longer.
- Alert Type 2 – Lower concentration event as defined by the company (typically set between about 5 – 10 ppm methane above background concentration) that is continuous.
- Alert Type 3 – Very low concentration event as defined by the company (typically set at 1 – 2 ppm methane above background concentration) over a 24 hour period or longer.
- Alert Type 4 – High or low concentration event as defined by the company that is intermittent.

Response I-7-209: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>500</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced

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<sup>498</sup> Dennis Prince, U.S. Patent 8,510,059.

<sup>499</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>500</sup> 87 FR 74744-74745 (December 6, 2022).

methane detection technology program, including the final action levels that apply to continuous monitoring.

#### 7.3.6.4 Minimum Detection Level

Comment: Commenters (0590-Honeywell, 0844-EDF *et al.*, 1172-Qube Technologies Inc. (Qube)) provide feedback in response to EPA's request on how to incorporate minimum detection levels in the continuous monitoring system framework.

Commenter (0590-Honeywell) states a continuous monitoring system's minimum detection level depends on the distance of the monitor to the system. Since these systems monitor continuously as compared to semiannual or quarterly OGI surveys, the commenter suggests EPA set the minimum detection level for continuous monitoring systems higher than the OGI detection level. For the sake of consistency, the commenter suggests EPA set the minimum detection threshold at 10 kg/hr, which aligns with EPA's alternative screening method.

Commenter (0844-EDF *et al.*) believes EPA should allow for continuous monitoring approaches with detection limits as low as permissible screening approaches as long as equivalent emission reductions can be demonstrated. Most continuous monitoring approaches must also be paired with some degree of OGI follow-up. Operators should be required to perform a follow-up OGI survey if emissions are detected in excess of predicted, permitted emissions. To minimize false alarms, this would require quantitative measurement technology, continuous emissions modeling, and extensive recordkeeping.

The commenter (0844-EDF *et al.*) states if EPA targets a 90 percent reduction, for example, it can work backwards to determine the (a) detection capabilities, (b) frequency of screening, and (c) follow up work practices that together would achieve this goal. To ensure a technology can reliably detect at a given threshold like 10 kg/hr, EPA will have to consider at least five parameters: distance from the source, probability of detection, frequency of detection, wind speed, and temperature/atmospheric-stability class. EPA will also have to evaluate the follow-up work practices associated with detections to ensure a certain reduction target is met. For example, emissions detected by a screening technology that is only capable of 100 kg/hr will be very large, may require repair on short timelines to achieve significant reductions (and in many cases may not be able to show equivalency regardless of repair speed). In most screening approaches, there will also be challenges in determining fugitive emissions versus allowable high emission events and situations where emissions cannot be pinpointed or have disappeared since being detected by screening.

Commenter (1172-Qube Technologies Inc. (Qube)) has demonstrated through controlled testing the ability to reliably detect emission rates below 1 kg/hr. Many continuous measurement systems on the market, including the commenter's, can easily detect emission rates of 10 kg/hr. Continuous measurement has the added benefit of surveying more than six times a year; it surveys 365 days of the year, meaning that emissions reductions would greatly exceed those of the mobile approach. The commenter therefore also believes that the 10 kg/hr threshold is unnecessarily high based on available continuous measurement technology and would propose a screening threshold of 1 kg/hr to ensure that all important sources are captured.

The commenter (1172-Qube) states that rigorous evidence must be presented to demonstrate that the method chosen achieves the performance metrics required. Many technology providers claim to achieve certain performance but without sufficient evidence. Rigorous controlled release testing should be mandatory across a broad range of conditions to develop probability of detection curves and/or surfaces that, at a minimum, establish probability of detection of a method as a function of emissions rate, wind speed, and any other relevant variables than impact detection. Testing must be performed under a broad range of environmental conditions.

Response I-7-210: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>501</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the final action levels that apply to continuous monitoring.

#### 7.3.6.5 Frequency of Data Readings

Comment: Commenters (0590-Honeywell, 0780-LongPath, 0791-Airdar) provide feedback in response to EPA’s request on appropriate frequencies of data readings under the continuous monitoring system framework.

Commenter (0590-Honeywell) urges EPA to define continuous monitoring broadly to be as inclusive as reasonably possible, rather than limiting what qualifies as continuous monitoring to a detailed set of technology specifications. The commenter suggests for a system to be considered continuous, it should at a minimum have a daily reading to align improved environmental benefits as predicted by the literature.<sup>502</sup>

Commenter (0780-LongPath) believes the frequency of data readings or reported emission rate values (whether detection or quantification readings), should be defined so as to differentiate between spot-check survey methods and continuous monitors. That is, a definition is needed to differentiate a “survey” technology from a “continuous monitoring” technology in terms of data frequency. If a matrix approach is adopted, frequency of data readings are needed to differentiate different areas of the matrix. The commenter recommends, as a starting point, defining “continuous monitoring” as a data reading of all important equipment once weekly.

The commenter (0780-LongPath) provides the following definitions. A “data reading” should be defined as a unit of detection or quantification of emissions from a monitored pad. A “data reading” should not be defined as the readout from a given sensor, such as a concentration or wind value. It is important that EPA ask technology providers to differentiate between sensor readouts (which can be as frequent as many Hz) and data readings, which require aggregation of data from various sensors and some averaging time through turbulent atmospheric conditions (and are therefore less frequent in time than sensor readouts).

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<sup>501</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>502</sup> See Kemp & Ravikumar Study.

Commenter (0791-Airdar) technology and other similar continuous monitoring technologies use concentration measurements to locate and quantify emissions. With a higher frequency of data, a more accurate analysis can be completed and the more the monitoring system can “see.” Airdar prefers data at a 10 second frequency for optimal performance.

The commenter (0760-Airdar *et al.*) states the framework for continuous monitoring (or a matrix describing performance requirements) will need to define frequency of data readings as a key performance requirement. A starting point could be at least once every two months with a 10 kg/hr detection threshold, to match the proposed Optional BSER for bimonthly surveys. To satisfy the less stringent emission follow-up requirements proposed here, however, the commenter would suggest a starting point of at least once every week with a 10 kg/hr detection threshold.

Response I-7-211: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>503</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the short-term and long-term rolling average action levels that apply to continuous monitoring.

#### 7.3.6.6 How to interpret the monitor data to determine what emissions are a detection versus baseline emissions

Comment: Commenter (0780-LongPath) believes the rule should be written with emission rate targets and not concentration value targets. With a target of emission rate rather than concentration value, the question of what constitutes a breach of the leak definition no longer becomes relevant; it is implied directly in the data reading. Instead, validation testing of the stated ability to detect can provide the assurances needed for regulators and owners and operators to know that compliance measures are being satisfied.

The commenter (0780-LongPath) adds that in terms of whether the leak definition should be defined as a static value (*e.g.*, 10 kg/hr) or as an increase over baseline conditions, some continuous monitoring systems, such as LongPath, offer customers a data product in which operations are assessed during a spin up period to establish a baseline emission rate and other characteristics for a given site. Alerts are then sent out when emission rates exceed expected baseline values with some statistical certainty. Many statistical tests can be used to determine statistically significant aberrations from baseline conditions.

The commenter (0780-LongPath) indicates that the leak definition could be arrived at in one of several ways:

- An emission rate in exceedance of a static threshold, determined for facility-types or other basis according to specific site characteristics.
- An emission rate in exceedance of a predetermined variance from the site-specific baseline emission rate.

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<sup>503</sup> 87 FR 74744-74745 (December 6, 2022).

- An emission rate in exceedance of some factor above the site-specific subpart W reported rate.
- An emission rate in exceedance of some increment above a predetermined emissions intensity target.

The commenter (0780-LongPath) recommends a leak definition based on static values, if that is what will be applied to the survey AWP. Ultimately, agreement between alternative technology options will provide the most clarity and ease of compliance for operators. If it were determined to be the best path forward, the commenter would, however, also support an EPA framework for continuous monitoring that is based on aberrations from a baseline value. However, the commenter points out that care must be taken under this approach. Many sites have substantially lower baseline values than others; EPA would not want to inadvertently permit some operators to maintain higher-emitting operations than others. Aberrations from a very low baseline value should not be penalized in the same way as aberrations from a very high baseline value from a site with the same number and types of equipment. Further, “natural” variability of emissions is much higher for some sites compared with other sites, complicating the statistical tests required to parse problematic emissions from normal operations.

The commenter (0780-LongPath) believes ultimately, whatever the leak definition, each technology will need to demonstrate, in blinded third-party validation testing, the ability to consistently and accurately (no or minimal false negative detections or missed leaks) identify when emissions from a monitored site are in exceedance of the leak definition rate. The CSU / METEC ADED program would be an excellent testbed for establishing these targets.<sup>504</sup> Validation demonstration results will be an important component of submitted fugitive emissions monitoring plans.

Response I-7-212: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>505</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA’s final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including procedures for establishing baseline emissions which are used to determine when emissions are above site-specific baseline and action-levels apply for continuous monitoring.

#### 7.3.6.7 How to determine allowable emissions versus leaks

Comment: Commenters (0756-Baker Hughes, 0760-Airdar *et al.*, 0780-LongPath, 0791-Airdar) provide feedback in response to EPA’s request on how to determine allowable emissions versus leaks.

Commenter (0756-Baker Hughes) is not aware of any detection method-including OGI-that is capable of inherently distinguishing “allowable emissions” from “leaks.” Distinguishing between allowable emissions and leaks are an element of an operator’s implementation plan for OGI, and similarly would be for continuous monitoring. This highlights an additional benefit of continuous

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<sup>504</sup> Advancing Development of Emissions Detection: <https://energy.colostate.edu/metec/aded/>.

<sup>505</sup> 87 FR 74744-74745 (December 6, 2022).

monitoring-correlating detection emissions data (*e.g.*, times, durations, locations, and quantifications) with the site's process data and history, *i.e.*, timing of known process venting that is detected as an emission by continuous monitoring. Over time, this data will provide a fuller picture of actual emissions (allowable and leaks).

Commenters (0760-Airdar *et al.*, 0780-LongPath) state the continuous monitoring system is to be operated continuously in accordance with the user manual of the specific technology, and the fugitive emissions monitoring plan submitted by the owner or operator, and subject to minimum uptime requirements. When a detected emission occurs, the commenters provided details in their commenter letter that included the following key steps:

- Step 1: "Alarm-candidate" generation
- Step 2: (Optional) Alarm-candidate assignment to equipment
- Step 3: Alarm-candidate classification
- Step 4: Emission Event Investigation Procedures
- Step 5: Repair

Commenter (0791-Airdar) uses a data analysis approach that can identify plumes in concentration and wind data while also providing quantification.<sup>506</sup> According to the commenter, continuous monitoring technologies like Airdar's have the ability to isolate plumes from all sources and quantify the source emission rate. With the ability to quantify emissions from any source, the determination of which emission sources are allowable is dependent on each piece of equipment and their allowable emitting rate. Emissions that exceed these specified allowances will be considered leaks.

The commenter (0791-Airdar) states the new capabilities introduced by continuous monitoring technologies that allow an entire site's emission rate to be determined opens the possibility to reconsider current approaches to fugitive emissions monitoring. Instead of focusing on periodic, component-specific surveys, continuous monitoring allows for the observation of the bigger picture. Existing approaches are missing important emission sources which is resulting in the underreporting of emissions. New continuous sensing approaches can see things that were missed before, but this will create challenges in comparing these new measurements to the old, regulated approaches. Writing the rules to match continuous monitoring systems to traditional EPA Method 21 monitoring may not be the best approach. This would ignore the capabilities of continuous monitoring and would miss the opportunity to innovate and improve. Possibly the simplest way to overcome this challenge is developing an overall site emission limit that would be tied to production of the site. This approach will help the environment and the people as this would drive operators to find innovative ways to stay below the emission limit and improve the accuracy of emission reporting through the capabilities of continuous monitoring technologies. The new approach will give operators the freedom to determine how best to reduce emissions, regardless of what was previously deemed an allowable source as long as overall site emission

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<sup>506</sup> This approach is published in their patent documents including U.S. Patent 8,510,059<sup>506</sup> and presented in 2019 at the AWMA Air Quality Measurement Methods and Technology Conference.

rates stay below the limit. Efforts spent on micro-managing the process of emission protocols can now be focused on reducing emissions in the most efficient way possible.

Response I-7-213: The EPA acknowledges recommendations received from commenters providing feedback in response to EPA's request on how to determine allowable emissions versus leaks. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>507</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including all requirements that apply to continuous monitoring.

#### 7.3.6.8 Response to other Compounds

Comment: Commenters (0756-Baker Hughes, 0780-LongPath) provide feedback in response to EPA's request for comment on response to other compounds.

Commenters (0756-Baker Hughes, 0780-LongPath) do not recommend that EPA require response to other compounds.

Commenter (0780-LongPath) says that given the urgent need to apply state-of-the-art emissions mitigations measures for methane. Extensive co-benefits of methane mitigation for the mitigation of VOCs will occur even for systems only capable of characterizing methane.

Similarly, commenter (0756-Baker Hughes) states that methane represents an approximate 16 percent of greenhouse gas emissions, however, is approximately 25 times more harmful to the environment. Methane also represents the largest component of fugitive emissions from oil and gas production facilities. Therefore, the commenter recommend that continuous monitoring should focus primarily on methane detection as opposed to other compounds.

Response I-7-214: The EPA acknowledges the commenters' request to not include a requirement for continuous monitors to be able to respond to other compounds besides methane. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>508</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including all requirements that apply to continuous monitoring.

#### 7.3.6.9 Meteorological Data

Comment: Commenters (0756-Baker Hughes, 0760-Airdar *et al.*, 0780-LongPath, 0791-Airdar, 0807-BP) provide feedback in response to EPA's request on how to incorporate meteorological data in the continuous monitoring system framework.

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<sup>507</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>508</sup> 87 FR 74744-74745 (December 6, 2022).



Commenter (0756-Baker Hughes) states that regarding meteorological station distance, the commenter's LUMEN Terrain uses one base station per monitoring site. These base stations are equipped with a meteorological station and are installed within the site itself providing the real-time weather data for the individual detection nodes in close proximity. Other continuous

Commenter (0780-LongPath) states the specifications listed by each technology in the monitoring plans will need to be vetted and validated as part of third-party blind testing. The commenter indicates that the two types of meteorological data that will need to be submitted as part of the monitoring plan are meteorological data criteria for initial siting of monitors meteorological data criteria for monitoring.

Commenter (0780-LongPath) suggests that EPA restrict the use of gridded datasets for use in emissions monitoring from any platform (ground-based or remote) and instead impose an acceptable radius for local meteorological measurements to be applied (*e.g.*, 10 miles). A recent publication on the impacts of microclimatic conditions provides, in the first paragraph of the introduction, a helpful literature review describing problems with gridded climate data products for parameterizing local-scale conditions<sup>509</sup> (*i.e.*, a clear justification for restricting the use of gridded datasets as a source of meteorological data for emissions characterization from oil and gas).

Commenters (0590-Honeywell, 0791-Airdar, 0780-LongPath) state all monitoring systems are affected by inclement weather conditions, and as such, technology providers should state the weather conditions the continuous monitoring system can operate in to achieve the required detection threshold. Windy day plumes disperse differently than on a calm day, leading to different influences of the same emission on a sensor. Some technologies are additionally impacted by temperature and background conditions (*e.g.*, snow cover for an aircraft or satellite platform). Similar to the operating envelope described in EPA's Appendix K, operating envelopes will need to be established for each alternative monitoring solution as part of the planned sensor placements for each monitored site. Operating envelopes will account for such information as the maximum distance between a given piece of equipment and the physical location at which atmospheric methane is being sampled, given the range of wind, temperature, visibility and humidity conditions expected at the monitored site.

Commenter (0590-Honeywell, 0760-Airdar *et al.*, 0807-BP) adds real time meteorological data can be used to estimate emissions rates. For purposes of operating continuous monitors, real time meteorological data should be used to verify that the continuous monitor is operating within its operating envelope. The location and proximity of meteorological stations for demonstration of this requirement should be included in the submitted fugitive emissions monitoring plan, as requirements vary by vendor and monitoring solution.

The commenters (0590-Honeywell, 0760-Airdar *et al.*) state local weather near an installed site can be monitored and tracked daily to determine the availability of the continuous monitoring system. Even in inclement weather, the continuous monitoring systems are still operational and capable of detecting leaks; however, the minimum detection threshold may be higher than

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<sup>509</sup> Aalto et al., "Revealing Topoclimatic Heterogeneity Using Meteorological Station Data."

specified. As soon as inclement weather passes, continuous systems will return to their specified performance.

The commenters (0760-Airdar *et al.*) state the continuous monitoring system is required to maintain detailed records of when data quality falls below set levels, and to support with other BSER when specifications are not met. As an example, continuous monitoring systems should record when meteorological conditions are outside the specified operating envelope or when data communication is not available. Supporting data from third-party blind testing is required to demonstrate and verify that the technology meets stated specifications across the conditions representative of each of the geographies and sub-climates for proposed use. These tests determine the operating envelope.

These test variables should include:

- Humidity ranges and impacts on sensors
- Temperature ranges
- Wind speed ranges
- Snow or other groundcover that may affect sensors
- Obstruction of sensors with dust, snow or ice
- Availability of network connectivity
- Availability of power

Response I-7-215: The EPA acknowledges the commenters input on how to incorporate meteorological data in the continuous monitoring system framework. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>510</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including how any meteorological data used are collected or sourced when associated with continuous monitoring.

#### 7.3.6.10 Measurement Systems Data Quality Indicators

Comment: Commenters (0780-LongPath, 0791-Airdar) provide feedback in response to EPA's request on how to incorporate data quality indicators in the continuous monitoring system framework.

Commenter (0780-LongPath) states that with respect to the quality of sensor data, each individual continuous monitoring solution will have different data quality indicators, depending upon the sensor type and usage. Specifications for data quality assurance and quality control will need to be documented and tested in third-party blinded validation under these stated operating specifications. Important operating conditions for demonstration testing include the impacts on sensors and quantification methods of the following variables: humidity, temperature, wind

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<sup>510</sup> 87 FR 74744-74745 (December 6, 2022).

speed, wind direction, groundcover (*e.g.*, snow), atmospheric conditions (dust, snow, rain, fog), obstruction of sensors (snow, dust, ice) network connectivity, power.

The commenter (0780-LongPath) adds with respect to the quality of emission rate or detection data (the quality of a data reading), each continuous monitoring method will need to demonstrate how uncertainty bars associated with each data reading are calculated and validated. The commenter provides additional technical detailed recommendations related to the quality of emission rate at detection data in their comment letter. The commenter reemphasizes that regardless of the methodologies used for uncertainty characterization by a particular continuous monitor, the validity of the technique must be demonstrated during third-party blind testing. In particular, it must be demonstrated during third-party blind testing that the continuous monitoring system is capable of meeting stated minimum threshold of detection and leak definition targets with statistical robustness, given emission estimate uncertainties as described here. This can functionally be determined by ensuring that false negatives (missed detections) of the target emission rate occur no more than, for example, 90 percent of the time during blinded testing.

Commenter (0791-Airdar) states different data quality objectives may exist depending on the type of monitoring being performed. Many public ambient monitoring stations are concerned with high readings of concentrations while a system like Airdar is concerned with identifying the baseline or zero point to identify emission plumes. Having a stable baseline is advantageous, but if the baseline is not stable, performing calibrations to adjust for a moving baseline will help to overcome this challenge. Properly defining the baseline will give higher confidence to the quantification of emissions and uncertainty in the baseline can introduce errors. Identifying the effects of temperature, humidity, and other variable is also important as these variables can affect the readings taken by the sensor. Identifying these effects will help to define a better baseline.

Response I-7-216: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>511</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including data quality indicator requirements that apply to continuous monitoring technologies seeking ATM approval.

#### 7.3.6.11 Calibration Requirements and Frequency of Calibration Checks

Comment: Commenters (0780-LongPath, 0791-Airdar) provide feedback on EPA's request for comment on calibration requirements and frequency of calibration checks.

Commenter (0780-LongPath) emphasizes that different continuous monitoring technologies have different calibration needs. For example, the differences in calibration requirements or sensitivity to changes in humidity for metal oxide sensors compared with optical point sensors is substantial. Other sensors, such as the dual frequency comb spectrometer used by the commenter

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<sup>511</sup> 87 FR 74744-74745 (December 6, 2022).

do not require any initial or ongoing calibration at all.<sup>512</sup> Therefore, technology-specific fugitive monitoring plans must accompany technology-agnostic general continuous monitoring frameworks. It is critical that stated specifications for calibration be firmly rooted in the peer reviewed literature. Inability of a monitoring solution to justify stated calibration protocols in the peer reviewed literature should be disqualifying for sensor use – despite a wide variety of monitoring solutions and technologies, all solutions rely on a relatively small set of sensor types, for which academic research is adequately available.

The commenter (0780-LongPath) emphasizes that in addition to requiring calibration specifications in the academic literature, it will be incumbent upon technology providers to prove these requirements in third-party blinded testing. The length of blind testing must span some factor on the stated calibration time frame to ensure that sensor drift within the stated windows does not occur. For example, if a solution states a calibration schedule of once every week, then the sensor should be tested over a period of at least 4 weeks to amass a reasonable statistical sample size demonstrating that the system meets stated drift specifications. The conditions of blind testing should also span all conditions expected in the operating environment shown in the peer reviewed literature to influence drift and calibration needs.

Commenter (0791-Airdar) states to ensure measurement accuracy, a requirement to include calibration checks should be included in the new rule. Calibration data is used to ensure that the correct baseline of emissions is taken to allow for location and accurate quantification of abnormal emission events. The calibration frequency is dependent on the sensor being used, as it is mainly determined by the stability of the sensor's baseline reading. In the commenter's experience, calibration needs to be completed at enough of a frequency to understand how the baseline varies over time and be able to separate the baseline from the emission source(s). Calibration is also required to confirm that the sensors are functioning. This will provide more certainty and provide operators, regulators, and communities with confidence in monitoring emissions.

The commenter (0791-Airdar) notes understandably, a calibration requirement can become labor intensive for operators when there are several sensors located across a large facility. However, the commenter has found a solution for making calibrations more convenient by using a central sensor connected via tubing to several remote sample inlets placed across a facility. The need to calibrate several monitors is reduced to one which can be done remotely, without requiring personnel to be on-site, saving time and effort while allowing for higher frequency of calibrations.

Response I-7-217: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>513</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the quality assurance/quality control criteria (*i.e.*, initial and ongoing calibration procedures, data quality indicators, and data quality

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<sup>512</sup> Waxman et al., "Intercomparison of Open-Path Trace Gas Measurements with Two Dual Frequency Comb Spectrometers."

<sup>513</sup> 87 FR 74744-74745 (December 6, 2022).

objectives) that apply to continuous monitoring technologies seeking ATM approval. The final rule specifies that the fugitive emissions monitoring plan where continuous monitoring will be used to demonstrate compliance must include a discussion of the system calibration requirements, including but not limited to, the calibration procedures and calibration schedule for the detection systems and meteorology systems.

#### 7.3.6.12 How Downtime Should be Handled

Comment: Commenters (0588-Project Canary, 0590-Honeywell, 0780-LongPath) provide insight on how operational downtime should be considered in the requirements of the rule.

Commenters (0588-Project Canary, 0780-LongPath) state that continuous monitor downtime can occur due to a variety of factors, such as sensor malfunction, communications failures, lack of cellular connection, lack of sun for long periods of time, or inability to operate due to extreme conditions (that is, environmental conditions that are outside of what is expected for the operating environment). It is important to differentiate between downtime due to shortcomings of the continuous monitor itself (*e.g.*, sensor malfunction, or inability to acquire cellular signal due to a local tower being down) from downtime due to truly external factors (for example, extreme weather events)

The commenter (0588-Project Canary) adds a single monitor is sufficient to find leaks if it is aligned with the correct wind direction. Given that the commenter typically installs three monitors at a location, the probability of having a total site outage is extremely low. As long as one monitor is operational, the commenter can determine whether a leak is potentially coming from the site and can be checked when the other monitors are fixed. The commenter notes that their dashboard system has a “flagging” approach to indicate whether a monitor is not operational or working improperly. While the commenter recommends that the monitor be fixed as soon as possible (considering technical feasibility issues), their system will still detect leaks faster than any sort of periodic monitoring system.

The commenters (0590-Honeywell, 0780-LongPath) recommend, for example, that if sensor malfunctions for a continuous monitor exceed 3 months (one quarter) then quarterly OGI BSER should be initiated to supplement lost fugitive emissions monitoring coverage.

Commenters (0767-Scientific Aviation *et al.*, 0791-Airdar) state when planned maintenance of the monitoring system is scheduled, it is preferable that this downtime does not coincide with other activities on site where a large emission event may occur (such as testing or commissioning of equipment). It is also important that facility operators cannot easily turn off the monitoring system or trigger its shutdown for safety and the accuracy of emissions profiles of the site. Downtime should be logged and explained in a record to demonstrate integrity and reliability of the monitoring program.

The commenter (0767-Scientific Aviation *et al.*) adds any uptime metric should be evaluated on no less than a two-week rolling basis to allow for repair time at remote facilities. Uptime requirements should also allow for an initial 60-day implementation period since a large-scale deployment of sensors can be challenged by fine-tuning parameters such as communications

(often relies on cell service or a need to build/configure existing SCADA), power availability (often relies on solar power), or other issues. Finally, where there is a data outage from a force majeure event there should be an allowable delay of repair for the monitoring system.

Commenter (0780-LongPath) states EPA should define reasonable percentages of downtime to be expected during the normal course of operation. When downtime due to shortcomings of the continuous monitor exceed the allowable percent, then the EPA should specify that other BSER must supplement measurements.

Response I-7-218: See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>514</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program, including the operational downtime requirements that apply to continuous monitoring.

#### 7.3.6.13 How to Handle Situations where the Source of Emissions Cannot be Identified Even when the Monitor Registers a Leak

Comment: Commenters (0756-Baker Hughes, 0780-LongPath, 0791-Airdar) note that EPA is seeking comment on how to handle situations where the source of emissions cannot be identified even when the monitor registers a leak.

The commenter (0780-LongPath) indicates that for circumstances in which an emission event is not mitigated with the prescribed procedures, the root cause and follow-up steps will need to be reinitiated after a stated number of days or weeks have passed.

The commenter (0791-Airdar) states if strong patterns in the ambient data indicate a large source, something must be present to explain this observation. It is possible that a continuous monitoring system could detect a false positive leak, but this is highly unlikely as the sensor outputs would need to fail in a pattern that matches the changing wind.

The commenter (0791-Airdar) adds often, OGI camera inspections are announced visits and a facility may be on their "best behavior" when these inspections are performed. Like smiling and looking your best when getting your picture taken, facilities will want to look their best during these inspections. There are situations where intermittent monitoring techniques like OGI cameras or drones cannot confirm a leak identified by a continuous monitoring system because a facility is on its best behavior when an inspection happens. The commenter's work in several projects has shown that facilities operate differently when an announced inspection is happening.

Commenter (0756-Baker Hughes) recommends that the operator's implementation plan delineate how to evaluate the detection of emissions, including the time, duration, location, and quantity. A site's process data and history provide important context with respect to the source of an emission, such as the timing of known process venting. A plan can provide further detail for

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<sup>514</sup> 87 FR 74744-74745 (December 6, 2022).

determining those circumstances when a follow up inspection with OGI is appropriate. The source for a leak can be confirmed at such time.

Commenter (0756-Baker Hughes) states emission localization is one the primary features of continuous monitoring along with detection and quantification. As an example, LUMEN Terrain provides the localization of every emission source with an accuracy of approximately +/-5 meters and displays this information as an overlay or “heat map” on aerial site imagery via the platform dashboard. This results in the determination of which equipment group or area of the site an emission originates from. In the majority of instances this provides enough information to identify the exact location without the need for follow-up inspections methods such as handheld OGI cameras. In the rare event localization results point to an area of high congestion with multiple potential leak source, and/or environmental conditions such as extreme winds reduce the accuracy of localization then follow up inspections with alternative technologies might be warranted.

Response I-7-219: See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on advanced methane detection technologies, including alternative periodic screening and alternative continuous monitoring systems.<sup>515</sup> Please also see section X.B of the preamble to the final rule which details EPA’s final standards related to the use of alternative periodic screening and alternative continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program. The final rule specifies the elements the fugitive emissions monitoring plan must contain where alternative technologies will be used to demonstrate compliance and the elements required to be included in the request for ATM approval.

### ***7.3.7 3<sup>rd</sup> Party Validation Testing***

Comment: Commenters (0756-Baker Hughes, 0780-LongPath) offer recommendations related to 3<sup>rd</sup> party validation testing.

Commenter (0756-Baker Hughes) recommends that third-party labs or testing sites are used to verify the minimum detection level, detection probabilities, and quantification accuracy. For reference, a widely used and accepted testing methodology is that developed by METEC at Colorado State University. The commenter further recommends that the criteria for the data set required for third-party verification should include reasonable timeframes, such as XXX hours or 30 days of field data, and not require data collected from different seasons or weather events. The commenter notes that LUMEN Terrain test data from various customer installations has shown very little impact on system performance as a result of seasonal environmental changes. This technology also has real-time diagnostics for temperature and relative humidity used to make zero-drift corrections to maintain optimum accuracy. Therefore, data collection can occur over a relatively short time span.

Commenter (0780-LongPath) indicates that state-of-the-art facilities now exist that can provide third-party blinded testing of emissions monitoring methods and technologies<sup>516</sup> with protocols

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<sup>515</sup> 87 FR 74741-74745 (December 6, 2022).

<sup>516</sup> <https://energy.colostate.edu/metec/>.

developed under collaborative and transparent processes involving multiple stakeholders (academics, industry, technology experts).<sup>517</sup> The METEC test facility and ADED protocols were developed with the support of federal funding, signaling the federal government's own investment and support of such methods for validating monitoring technologies.

The commenter (0780-LongPath) states all alternative monitoring technologies (survey and continuous approaches) should be required to perform third-party blind testing at a facility like METEC and under a protocol like ADED. For conditions that cannot be adequately simulated at METEC (like high humidity), but that are known to impact sensor quality, supplemental third-party blind testing must be demonstrated.

The commenter (0780-LongPath) believes the fugitive emissions monitoring plan submitted for a given monitoring technology would need to require response function matrices showing sensitivity to such conditions as wind speed, wind direction and variability, temperature, humidity and groundcover (*e.g.*, snow). This matrix of sensitivities (which, collectively, are the operating envelope) could be generated seasonally for each region or basin using average conditions for the monitoring area and time period.

Response I-7-220: See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on advanced methane detection technologies, including alternative periodic screening and alternative continuous monitoring systems.<sup>518</sup> Please also see section X.B of the preamble to the final rule which details EPA's final standards related to the use of alternative periodic screening and alternative continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program. The final rule specifies the elements the fugitive emissions monitoring plan must contain where alternative technologies will be used to demonstrate compliance and the elements required to be included in the request for ATM approval.

### ***7.3.8 Fenceline Monitoring***

Comment: Commenter (0809-Earthjustice) believes it is necessary to revise the emission standards to require fenceline monitoring as a control technology for oil and gas sources, as EPA has since required for petroleum refineries. In 2015, EPA determined there were developments in control technologies that required revisions to the MACT standards under CAA section 112(d), particularly to require monitoring and corrective action for benzene at the fenceline of source facilities to assure compliance with the standards and improve control of fugitive emissions.<sup>519</sup> Robust monitoring requirements, including fenceline air monitoring, are necessary to ensure continuous compliance with emissions standards, as required under the CAA.<sup>520</sup>

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<sup>517</sup> Advancing Development of Emissions Detection: <https://energy.colostate.edu/metec/aded/>.

<sup>518</sup> 87 FR 74741-74745 (December 6, 2022).

<sup>519</sup> See Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards; Final Rule, 80 Fed. Reg. 75,178, 75,191 (Dec. 1, 2015).

<sup>520</sup> See 42 U.S.C. § 7412(d)(6); see also *id.* § 7602(k).



The commenter (0809-Earthjustice) notes EPA has proposed allowing two refineries in Corpus Christi, Texas, to use LDSN technology as an alternative means of emissions limitation.<sup>521</sup> EPA based this proposed decision on findings that LDSN allows leaks to be detected and repaired more quickly than EPA Method 21 and is more cost-effective, and that LDSN can detect leaks at emission levels below those detectable by OGI and other advanced leak detection technologies.<sup>522</sup> EPA should continue to consider the inclusion of LDSN technology as an LDAR compliance pathway in its NSPS and NESHAP rulemakings more broadly, provided the continuous monitoring is done rigorously and can be shown to achieve equivalent or greater emission reductions.

The commenter (0809-Earthjustice) states as EPA recently stated in support of the 2015 Petroleum Refinery Sector NESHAP rule's ("2015 Refinery Rule") fenceline monitoring provisions, periodic monitoring requirements— such as quarterly LDAR—will “often miss periodic emission events” that “can contribute significantly to a facility’s emissions.”<sup>523</sup> Fenceline monitoring better captures these periodic releases, resulting in more effective management of fugitive emissions from oil and gas facilities. Accordingly, EPA should include fenceline monitoring as an LDAR technology in the final NSPS for the control of VOC and methane emissions, as well as in its reconsideration of the 2012 NESHAP rule and new CAA section 112(d)(6) review for the control of air toxics.

The commenter (0809-Earthjustice) adds, due to recent developments, any new fenceline monitoring requirements should be even stronger than the 2015 Refinery Rule, namely with the inclusion of continuous monitoring. Neighboring communities need a real-time, continuous measure of pollution, and EPA must require oil and gas facilities to quickly fix violations. Since 2015, refineries have now implemented fenceline monitoring nationwide and are implementing plans using real-time technology in Los Angeles. The first national benzene reports have shown how essential fenceline monitoring is to assure compliance with emission standards and identify serious pollution problems and health threats.<sup>524</sup>

The commenter (0809-Earthjustice) states within the oil and gas sector, EPA has tested Methods 325A/B for monitoring VOCs near two oil and gas production well pads in Texas and Colorado with promising results as to the utility of Methods 325A/B for oil and gas sources.<sup>525</sup> EPA also recently required a natural gas processing plant in Pennsylvania to operate a continuous ambient

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<sup>521</sup> Request for Approval of Alternative Means of Emission Limitation, 86 Fed. Reg. 56,934 (Oct. 13, 2021).

<sup>522</sup> EPA, Progress on LDAR Innovation, PDF at 6 (Jan. 28, 2021), [https://cfpub.epa.gov/si/si\\_public\\_record\\_report.cfm?Lab=CEMM&dirEntryId=350905](https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=CEMM&dirEntryId=350905).

<sup>523</sup> National Emission Standards for Hazardous Air Pollutants: Petroleum Refinery Sector; Final Rule, 85 Fed. Reg. 6,064, 6,078 (Feb. 5, 2020).

<sup>524</sup> EIP, Monitoring for Benzene at Refinery Fencelines (Feb. 6, 2020), available at <https://www.environmentalintegrity.org/wp-content/uploads/2020/02/Benzene-Report2.6.20.pdf>; S. Coast Air Qual. Mgmt. Dist., Rule 1180, Rule 1180 Guidelines, Rule 1180 Fenceline Monitoring Plans, <http://www.aqmd.gov/home/rules-compliance/rules/supportdocuments/rule-1180-refineryfenceline-monitoring-plans>.

<sup>525</sup> Adam P. Eisele et al., Volatile Organic Compounds at Two Oil and Natural Gas Production Well Pads in Colorado and Texas Using Passive Samplers, J. of Air & Waste Mgmt Assoc. (2016), <https://doi.org/10.1080/10962247.2016.1141808>.

air monitoring system for VOC and HAP emissions,<sup>526</sup> and similarly required a compressor station in Ohio to operate a continuous ambient air monitoring system for VOC and reduced sulfur compounds,<sup>527</sup> further demonstrating the feasibility and utility of requiring fenceline monitoring more broadly across the oil and gas sector.

Response I-7-221: In response to the solicitation for comment on the development of a framework for continuous monitoring technologies in the November 2021 proposal, the EPA proposed a regulatory approach for alternative continuous monitoring systems in the December 2022 Supplemental Proposal that was akin to the fenceline monitoring work practice promulgated by the EPA in 2015 as part of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the petroleum refinery sector (80 FR 75178; December 1, 2015). For details, please see discussion in section IV.B.2 of the December 2022 Supplemental Proposal.<sup>528</sup>

In the final rule, the EPA is preserving the continuing monitoring approach and associated work practice from the December 2022 Supplemental Proposal with some changes including specifying the requirements for operating continuous monitoring systems including using advanced methane monitoring technology to be approved by the EPA for this purpose. Please see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of alternative continuous monitoring systems and section XI.B.2 of the preamble to the final rule for EPA's responses to significant comments received on this topic and changes made to the final rule.

### **7.3.9 Continuous Monitoring Cost**

Comment: Commenters (0588-Project Canary, 0756-Baker Hughes, 0759-LongPath *et al.*, 0780-LongPath, 0791-Airdar)) believe continuous monitoring systems can be implemented cost effectively.

The commenter (0588-Project Canary) provides tables comparing the cost-effective values used for OGI in Colorado Reg 7, the cost of a continuous monitoring system per well-site would have to greater than over \$340,000 (low bound) to \$3.8 million (upper bound) a year for it to not be as cost-effective. As continuous monitoring systems last multiple years, these values are significantly greater than what the cost of a continuous monitoring system would be. Additionally, when these costs are viewed in terms of commodity pricing, they appear even more affordable. While the costs can be high for low-producing wells, for most of the wells, the cost of adding three monitors and one anemometer per well site adds well under \$0.50 per barrel of oil equivalent (BOE), and as low as \$0.10/BOE at some well pads. The commenter states that this

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<sup>526</sup> Consent Decree at 17-18, App. 8, United States v. MarkWest Liberty Midstream & Resources, LLC, No. 2:18-cv-00520-LPL (W.D. Pa. Apr. 24, 2018), ECF No. 2-1 [hereinafter MarkWest Consent Decree], <https://www.epa.gov/sites/default/files/2018-04/documents/markwest-cd.pdf>; MSI Trinity Consultants, Summary of Air Toxics and Meteorological Data from MarkWest's Harmon Creek Monitoring Stations, First Quarter 2020, at 1-1 (April 2020) (describing continuous monitoring of VOCs and air toxics), <https://foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-R3-2021-001431&type=Request> (record link entitled "Harmon Creek - 2020 1st Quarter - Fence Line Monitoring Data submitted").

<sup>527</sup> See MarkWest Consent Decree, *supra*, at 17, App. 7.

<sup>528</sup> 87 FR 74744-74745 (December 6, 2022).

adds less than one percent to commodity pricing overall and is generally considered cost-effective.

Commenter (0759-LongPath *et al.*) understands their solutions must be cost competitive before operators will adopt them at scale. As such, all providers regardless of the underlying technology (*e.g.*, tunable diode laser absorption spectroscopy (TDLAS), open-path laser, continuous OGI cameras and metal oxide sensors) have made meaningful strides to lower the cost of deployment by reducing the individual cost of each system deployed or increasing the number of sites covered per system. This is evidenced by the number and variety of continuous monitoring systems currently being piloted across industry. The cost competitiveness of continuous monitoring is further highlighted when taking into account the emission volumes. Because continuous monitoring leads to greater reductions in emissions through faster alerting and remediation, the cost of monitoring as a ratio of the volume of emissions reduced can be lower than intermittent technologies. In other words, for each ton of methane reduced, the cost per monitoring can be lower for continuous monitoring when compared to intermittent technologies.

Commenter (0780-LongPath) adds continuous monitoring is highly scalable. With modest capital investment, around 1000 LongPath sensors could provide cost-effective continuous monitoring for most of the Permian Basin of West Texas and Southeastern New Mexico. Already, LongPath is continuously monitoring more than 120,000 acres in the DJ, Anadarko, Delaware and Midland basins. Once LongPath's networked infrastructure is in place, any site in the area can be quickly and cost-effectively subscribed. This includes orphaned wells, which LongPath can monitor, quantify, and prioritize for plugging.

According to the commenter (0780-LongPath Technologies), continuous monitoring affords rapid repair, such that cumulative emissions to the atmosphere are tens to hundreds of times lower than survey approaches can provide. For example, a stuck dump was repaired in 2 days, resulting in a cumulative loss to the atmosphere of 300 Mcf. A bi-monthly or quarterly survey might not have discovered the leak for 2-3 months, which would have resulted in some 30-50 times higher cumulative emissions emitted to the atmosphere. The difference in gas lost between continuous monitoring and a theoretical quarterly survey would have been 13,500 Mcf, or roughly 10.4 t. At a market value of \$3.25/Mcf, a loss of 13,800 Mcf is roughly \$44,850 over 3 months. These losses dwarf the cost of the monitoring itself (and for many years) – a clear proof point that continuous monitoring is cost effective. Similarly, the social cost of methane (\$1,800/t) would equate to \$18,720 saved compared with quarterly LDAR.

Response I-7-222: The EPA acknowledges comments concerning the capabilities and cost of continuous monitoring technologies. However, the EPA does not find that continuous monitoring technology is the BSER for well sites because EPA does not have sufficient information to include this new but rapidly advancing technology in the BSER analysis; however, the EPA supports the use of continuous monitoring systems to detect fugitive emissions. The EPA is providing a pathway for owners and operators to utilize continuous monitoring technologies as part of the advanced methane detection technology provisions of the rule. Please see section X.B.2 of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (0791-Airdar) states continuous monitoring technologies that use sensors with a low detection limit are capable of putting an entire area under surveillance. This means that there is potential to develop more efficient and cost-effective emissions monitoring programs by combining fence line monitoring and LDAR programs. Continuous monitoring also ensures that resources are directed to the right problem, as demonstrated by the SAGD case study.<sup>529</sup>

Response I-7-223: EPA acknowledges the commenters support for the use of continuous monitoring. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>530</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program.

Comment: Commenter (0588-Project Canary) argues although continuous monitoring is a relatively new technology, it has already seen widespread deployment across multiple sectors. It is increasingly used in the exploration, production, and midstream segments of the oil and natural gas industry. The advent of technology solutions such as continuous monitoring has enabled cost-effective technology deployment and data acquisition. In turn, this has allowed operators to improve their operations. Continuous monitoring enables operators to deploy emissions management programs, under which operations are continuously monitored, leaks are more frequently detected, and emissions are more reliably measured.

The commenter (0588-Project Canary) notes 2021 saw a dramatic increase in continuous monitoring technology deployment. According to Darcy Partners, 71 percent of the exploration and production companies that they work with had already implemented or were planning to implement responsibly sourced natural gas (RSG) within two years.<sup>531</sup> According to the commenter, key drivers include encouragement by investors, competitive environmental, social, and governance (ESG) pressures to understand and improve operations, and the ability to employ continuous monitoring to produce differentiated products that can be sold into differentiated, certified, or responsibly sourced gas markets.

The commenter (0588-Project Canary) states that various non-governmental organizations (NGOs) have made statements around continuous monitoring systems for the oil and natural gas industry. For example, Jeremy Nichols, climate, and energy program director for the environmental group WildEarth Guardians, said continuous monitoring of emissions instead of just periodic inspections can provide an indication of what is happening at well sites. The sites typically include multiple wells, tanks, and other equipment.<sup>532</sup> Dan Grossman, senior director of

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<sup>529</sup> Dennis Prince et al., 2019.

<sup>530</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>531</sup> Jack Blears, Darcy Partners, Responsibly Sourced Gas (RSG) Movement Gaining Traction (2022), available at <https://darcypartners.com/research/certified-low-emissions-gas-gaining-traction>.

<sup>532</sup> Judith Kohler, Colorado oil and gas company aims to produce "cleanest molecules" anywhere, Denver Post (May 13, 2021), available at <https://www.denverpost.com/2021/05/13/xcel-energy-crestone-peak-cleaner-gas/>.

regulatory and legislative affairs at the EDF, stated that initiatives that include continuous monitoring systems are positive and might be a good model.<sup>533</sup>

The commenter (0588-Project Canary) states continuous monitoring has enabled the development of domestic and international certified RSG markets. In 2021 alone, nearly 75 operators in the US have committed to devoting resources to RSG markets. It is estimated that between 20 and 25 percent of the US natural gas market will be dedicated to RSG markets, meeting the needs of utilities and liquefied natural gas (LNG) buyers.<sup>534</sup> Continuous monitoring allow operators to demonstrate low emissions production and RSG markets are seeking low methane emissions intensity certificates.<sup>535</sup> Through partnerships with operators, the commenter has seen production-related methane emission reductions of an estimated 80 percent. This type of emissions measurement and performance will enable the industry to meet low or net-zero commitments across the energy sector.

The commenter (0588-Project Canary) notes, Kevin Book, a managing director at ClearView Energy Partners LLC, has observed that RSG is key for parts of the world where efforts are underway to maximize clean, affordable energy output.<sup>536</sup> EQT, the largest U.S. natural gas producer, is working to certify their natural gas from their Appalachian natural gas production.<sup>537</sup> The commenter's (0588-Project Canary) standards for RSG include and build upon the standards set forth by ONE Future, the American Gas Association, NORSOK, ISO, and the API.<sup>538</sup> Continuous monitoring systems allow for American oil and natural gas companies to show how clean our production is – especially relative to other locations around the world.

Response I-7-224: EPA acknowledges the commenters support for the use of continuous monitoring. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>539</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program.

### ***7.3.10 Other Programs (Colorado and Alberta, Canada)***

Comment: Commenter (0759-LongPath *et al.*) states the AER is a leader in oil and gas methane regulation and has implemented progressive policies to enable the adoption of emerging LDAR technologies. Over the past two years, the AER has approved numerous alternative LDAR schemes that include aerial LiDAR, truck-mounted sensors, and innovative work practices using

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<sup>533</sup> Statement from Jon Goldstein, Director of Regulatory & Legislative Affairs, Energy, Environmental Defense Fund (Sept. 23, 2020), available at <https://www.edf.org/media/new-air-quality-rules-tackle-pollution-during-early-stages-oil-and-gas-operations>.

<sup>534</sup> Project Canary, What is RSG? A Definitive Guide to Differentiating Gas and the Certification Process (Nov. 19, 2021), available at <https://www.linkedin.com/pulse/what-rsg-definitive-guide-differentiating-gas-certification-/>.

<sup>535</sup> *Id.*

<sup>536</sup> Jamison Cocklin, RSG Seen as Key to Unlocking More Natural Gas Export Demand in Developed Countries, Natural Gas Intelligence (Nov. 24, 2021), available at <https://www.naturalgasintel.com/rsg-seen-as-key-to-unlocking-more-natural-gasexport-demand-in-developed-countries/>.

<sup>537</sup> *Id.*

<sup>538</sup> *Id.*

<sup>539</sup> 87 FR 74744-74745 (December 6, 2022).

handheld instruments. Most recently, the AER has approved at least two alternative LDAR pilot programs based on continuous measurement. Together, these two programs encompass dozens of production facilities across Alberta. Modeling of these programs suggest that they will reduce fugitive methane emissions by more than the conventional AER program that requires annual or triannual OGI. Notices of the approvals are available.<sup>540,541</sup>

Commenter (0759-LongPath *et al.*) states Colorado's Regulation 7 Pre-Production Monitoring rule is the first state regulation to incorporate continuous monitoring into its programs. This was driven by Senate Bill 181 which had a requirement for continuous methane and VOC monitoring in response to public health concerns. The rule is non-prescriptive on the sensor type, sensor placement, and response requirements, and asks producers to submit a monitoring plan detailing their chosen technology, sensor siting, calibration protocols, and validation. Rather than ask producers to respond to every alert detected with a handheld OGI inspection, operators set three levels of alerts, each of which necessitates a different response, and allows for operators to check but not dispatch teams to routine emissions generated as part of normal operators, such as a compressor actuating. Alert levels and operator response are spelled out in each operator's standard operating procedure, detailed as part of the monitoring plan. At the lowest level of alert, operators could review SCADA data; at a secondary alert, operators could decide to review with an internal team; and at the highest level of alert, operators could decide to dispatch a team within the hour. All responses must be logged and submitted to the state as part of monthly reporting. In addition to the state-level continuous monitoring program, continuous monitoring systems are also being adopted by local governments, such as cities and counties including Broomfield, Aurora, Erie, Weld County, and Dacono.

Commenter (0588-Project Canary) similarly states that the implementation of Colorado Regulation 7 allows for the use of continuous monitoring. Under Colorado Regulation 7, the frequencies of OGI inspections decreases over time, from an initial frequency of once every six months. The idea underlying this policy is that continuous monitoring data can be compared to the OGI data for leaks found. There will be times when OGI inspection is not being conducted and the continuous monitor detects an emission. These events would be categorized as upside to the continuous monitoring program and leak rates would be shown to be greatly reduced due to the continuous nature of monitoring. As confidence in the continuous monitoring system grows, routine LDAR inspection frequencies could be lessened and OGI would be used more for pinpointing the leak.

Commenter (0588-Project Canary) states local governments value the importance of continuous monitoring systems and have adopted and implemented requirements in efforts to inform their communities. For example, Broomfield, Colorado has implemented continuous monitoring and

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<sup>540</sup> <https://www.newswire.ca/news-releases/qube-technologies-and-ember-resources-receive-regulatory-approval-for-fixedmethane-sensor-monitoring-815430339.html>.

<sup>541</sup> <https://www.qubeiot.com/resources-news/blog-post-title-one-pmm28-tgrsf-jslgd>.

installed six monitoring stations.<sup>542</sup> Also, Aurora, Colorado reached an operator agreement with ConocoPhillips for the use of continuous monitoring for the life of their well.<sup>543</sup>

Response I-7-225: EPA acknowledges the commenter's information related to alternatives to traditional fugitive emissions monitoring and repair programs. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>544</sup> Please also see section X.B.2 of the preamble to the final rule which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program.

Comment: Commenters (0776-CDPHE, 0844-EDF *et al.*, 1267-CA AG *et al.*) state Colorado's regulatory approach to leak detection and AIMM inspection of well production facilities is multi-layered. First, as of a December 2021 program update, all new well production facilities must conduct monthly AIMM inspections unless they are constructed and operated with specified design alternatives.<sup>545</sup> Existing well production facilities must conduct inspections at a frequency that depends on the actual, uncontrolled VOC emissions from a storage tank.<sup>546</sup> Frequencies range from annual, for the smallest sites, to monthly for the largest sites and many sites in disproportionately impacted communities.<sup>547</sup>

The commenter (0775-CDPHE) states after Colorado updated the AIMM provisions of its LDAR rules in 2017, Colorado requested that a representative from EPA Region 8 participate as a member of Colorado's AIMM Team to evaluate alternative LDAR technologies and programs seeking approval under Colorado's rules. Since then, an EPA Region 8 representative has been involved in the review of all alternative AIMM applications that have been submitted to Colorado and has acted as a liaison to other EPA offices, including headquarters and Office of Air Quality Planning and Standards (OAQPS), on various matters pertaining to such applications and the alternative LDAR technologies/programs. Colorado has also provided significant feedback to EPA regarding the AMEL as it relates to alternative LDAR technologies and programs for oil and natural gas production, including the current comments being provided here for purposes of EPA's updated proposal.

Response I-7-226: EPA acknowledges information commenters provided that is related to alternatives to traditional fugitive emissions monitoring and repair programs. See discussion in section IV.B.2 of the December 2022 Supplemental Proposal for a discussion on alternative continuous monitoring systems.<sup>548</sup> Please also see section X.B.2 of the preamble to the final rule

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<sup>542</sup> Brooklyn Dance, Broomfield City Council approves 2021 oil and gas air quality monitoring agreements, Broomfield Enterprise (Dec. 9, 2020), available at <https://www.broomfieldenterprise.com/2020/12/09/broomfield-city-council-approves-2021-oiland-gas-air-quality-monitoring-agreements/>.

<sup>543</sup> Draft Oil and Gas Operator Agreement Between ConocoPhillips Co. and City of Aurora, Colorado (May 29, 2019), Exh. C, at 12, 15.3, available at [https://p1cdn4static.civicle.com/UserFiles/Servers/Server\\_1881137/File/Residents/Oil%20and%20Gas%20Drilling/ConocoPhillips%20Draft%20Operator%20Agreement%20May%2029%202019.pdf](https://p1cdn4static.civicle.com/UserFiles/Servers/Server_1881137/File/Residents/Oil%20and%20Gas%20Drilling/ConocoPhillips%20Draft%20Operator%20Agreement%20May%2029%202019.pdf).

<sup>544</sup> 87 FR 74744-74745 (December 6, 2022).

<sup>545</sup> 5 Colo. Code Regs. § 1001-9:D.II.E.4.e-f (adopted Dec. 17, 2021).

<sup>546</sup> Id. § II.E.4.g. tbl. 4.

<sup>547</sup> Id.

<sup>548</sup> 87 FR 74744-74745 (December 6, 2022).

which details EPA's final standards related to the use of continuous monitoring systems for detection of fugitive emissions under the advanced methane detection technology program.

Comment: Commenter (0846-Arolytics Inc.) states in only 2 years, Alberta has granted 9 approvals for Alternative LDAR programs that allow for variance in leak detection methodologies, and site visit frequencies. Flexibility is extremely high, though burden of proof is high and rules very specific. To date, many of the largest producers/operators in Canada have received approvals and are now operating innovative Alternative LDAR programs in Alberta. One of the approvals was also granted to a multi-producer consortium. Approvals have also been granted to small/midsize private companies. Unlike Colorado, the AER does NOT approve individual alternative detection technologies. The AER approves only alternative Fugitive Emission Management programs, which may include alternative detection technologies, and or variation in the required visit frequencies.

Commenter (0846-Arolytics Inc.) argues the outcome is well defined, in that any proposal must provide an equivalent level of emissions reduction to that of the default plan. Alberta sets out a clear process for applications, approval, and management of Alternative Programs. Most of the approved plans to date represent a collaboration between the producer/operator and several technology vendors. Normally some company-specific data is used in the formulating the design and in preparing the application, as well as some technology-specific thresholds. Many producers and operators apply for variances in timing and frequency of surveys concomitant with the capability of the detection technology they use, and the conditions expect at the use location. The approval is very much focused on implementation, and the Alternative Plan replaces the regulatory default plan for the company assets in question. The producer/operator must submit progress reports that compare methane reductions achieved vs. proposed.

Commenter (0846-Arolytics Inc.) adds by this mechanism the regulator will learn a lot about alternative technologies and programs. In Alberta, an Alternative Plan normally represents the lowest cost pathway to meet the emission reduction target, as guided by a model. The lowest cost pathway is normally modelled using a scenario model that incorporates cost, detection technology, leak likelihood, *etc.* Several models are available. The models show that lowest cost / most effective and efficient pathway differs for each producer/operator depending on asset type, geographic location. The Alberta regulator has offered several lessons from its early experience (from the regulator's website<sup>549</sup>).

Response I-7-227: EPA acknowledges the commenter's information related to alternatives to traditional fugitive emissions monitoring and repair programs. See discussion in section IV.B of the December 2022 Supplemental Proposal for a discussion on advanced methane detection technologies.<sup>550</sup> Please also see section X.B of the preamble to the final rule which details EPA's final standards related to the use of alternative technologies for detection of fugitive emissions under the advanced methane detection technology program.

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<sup>549</sup> Website at: <https://www.aer.ca/protecting-what-matters/holding-industry-accountable/industryperformance/methane-performance/alternative-fugitive-emission-managementprogram-approvals>.

<sup>550</sup> 87 FR 74740-74746 (December 6, 2022).



## 7.4 Use of Information From Communities and Others

### 7.4.1 General Comments

#### 7.4.1.1 Community Monitoring Program Support

Comment: Several commenters (0195-EEN, 0770-NPRC, 0780-LongPath, 0844-EDF *et al.*, 0949-Liveable Arlington, 1338-Lexington-CAN) request that EPA create a community emissions monitoring program to ensure community members can take action to protect their health and hold drilling accompanys accountable to reduce emissions.

Commenter (0195-EEN) suggests strengthening the proposed rule by developing a process for the incorporation of monitoring data from third parties. The expanded monitoring may result in a major public health benefit.

Commenter (0770-NPRC) believes EPA has an obligation to strengthen its November 2021 Proposal and advance rules that leave no loopholes nor future opportunities for methane pollution from oil and gas infrastructure. As one testifier at EPA's December public hearing noted, "We have learned that most oil and gas operators only respond to that which is required by rule or law." Northern Plains' experience interacting with oil and gas companies in Montana confirms this. The commenter urges EPA to determine a way to incorporate methane pollution monitoring results generated by community groups and other third parties into EPA's standards and prioritization process for fixing major leaks.

Commenter (0780-LongPath) emphasizes that there is no question that, the faster identification and repair of leaks and malfunctions can occur, the greater the benefits to communities disproportionately impacted by emissions, the industry's bottom line, and the global community impacted by climate change. Continuous monitoring affords this. According to the commenter, the benefits of continuous monitoring are many and impact many stakeholders: neighboring communities in oil and gas production areas, the environment and global communities grappling with a changing climate, and an industry that is working to reduce waste and cut emissions.

Commenters (0942-CleanEarth4Kids.org, 0937-Fort Berthoud POWER, 0947- ANHE-CO *et al.*, 1339-Waterway Advocates) suggest developing a community monitoring program for frontline communities that educates and certifies community members as monitors and requires immediate follow up of their complaints.

Response I-7-228: The EPA acknowledges supportive comments.

In the November 2021 proposal, the EPA solicited comment on the use of information collected by communities and others to address large emissions events, which the December 2022 Supplemental Proposal defined as "super-emitter emissions events." The EPA did not propose any standards in the November 2021 Proposal but did so in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental

Proposal.<sup>551</sup> Please also see section X.C of the preamble to the final rule which details EPA’s final standards related to the super emitter program.

Comment: The commenter (0844-EDF *et al.*) urges EPA to finalize a framework allowing third parties to detect and report emissions to EPA and in response to credible data, the operator would be required to fix the leak. The commenter believes EPA can set parameters to ensure reported data is accurate, ensure the program helps to empower communities to use different technologies and methods, and ensure technologies are used safely and properly. In addition, the commenter believes EPA should also make all reported emissions publicly available. This type of program will foster public trust and accountability, while increasing knowledge on leaks and helping to further reduce emissions.

The commenter (0844-EDF *et al.*) cites to multiple studies to show that super-emitters and abnormal process emissions are often not well-represented and national inventories often underrepresent emissions. This information is summarized in a later section.

Response I-7-229: The EPA acknowledges the commenter’s remarks regarding the need to finalize framework for detecting and reporting large emissions events.

In the November 2021 proposal, the EPA solicited comment on the use of information collected by communities and others to address large emissions events, which the December 2022 Supplemental Proposal defined as “super-emitter emissions events.” The EPA did not propose any standards in the November 2021 Proposal but did so in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>552</sup> Please also see section X.C of the preamble to the final rule which details EPA’s final standards related to the super emitter program.

#### 7.4.1.2 Enforcement/Third-Party Monitoring Concerns

Comment: Commenter (0946-MOGA) requests that EPA outline their explicit intention, direction and limitations when encouraging community engagement related to oil and gas production related facilities. The commenter notes that their primary concern is safety. Michigan’s oil and gas industry employees are arguably the most highly skilled, trained, insured and safety-oriented workforce in the United States. The commenter urges the EPA to clearly define their proposed “community engagement” intent and provide specific restrictions and associated guidelines to prevent injuries.

Response I-7-230: The EPA acknowledges the commenter’s concerns around safety and community engagement as it relates to the super emitter program.

The EPA proposed specific requirements for the super-emitter program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>553</sup> The proposal included provisions stipulating the qualifications and

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<sup>551</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>552</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>553</sup> 87 FR 74746-74755 (December 6, 2022).

requirements for notification of super-emitter emissions events by regulatory authorities and qualified third-party notifiers. To address concerns regarding community engagement or the expertise of the third party identifying the super-emitter event, the EPA proposed in December 2022 that any third party interested in identifying and notifying owners and operators of super-emitter emissions events must be preapproved by the Agency for the notification to be valid. The EPA is finalizing this requirement. Please also see section X.C of the preamble to the final rule which details EPA's final standards related to the super emitter program.

Comment: Commenter (0946-MOGA) expresses concern with how community data will be collected, the accuracy of the collected data and how the data will be used. The commenter believes that standards proposed in Appendix K to the proposed NSPS OOOOa and future NSPS OOOOb and EG OOOOc should be consistent and equal for both oil and gas small business and communities. The commenter requests that EPA very clearly determine and define the proposed "expansion of leak detection programs" to ensure consistent and repeatable results across the various platforms and data collection techniques used to collect data. The commenter also requests clarification in the proposed regulations with regards to how community-collected data will be validated for accuracy and how local regulatory agencies will use the data.

Response I-7-231: The EPA understands the commenter's concerns related to collection and use of collected data under the super emitter program.

The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>554</sup> Please see section X.C of the preamble to the final rule which details EPA's final standards related to third-party notifier certification, which includes requirements for detailing the procedures and processes to ensure the data collected is in compliance with the requirements of the rule.

Comment: Commenter (0831-AXPC) states that, while they support the public being able to participate in development of their communities and believe that they should be provided relevant information on what is going on in their communities, they have significant concerns related to what has been generally called "citizen science" – where members of the public are deputized to act as if they are employees of EPA. The commenter notes that it is difficult for them to comment on a mere concept without something more fleshed out and they state that they will provide additional information if and when EPA proposes regulatory text.

The commenter (0831-AXPC) states that the EPA seeks comment on how to allow for members of the public to use technology to search for super-emitters, but also potentially any types of emissions.<sup>555</sup> EPA and industry professionals are trained in how to operate, inspect, and monitor oil and natural gas sites without causing danger to themselves or others. The commenter contends that it is unclear to them why these requirements are being considered in the first place. According to the commenter, this provision appears to be duplicative of EPA's current system which allows members of the public to submit potential environmental violations.<sup>556</sup> They note

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<sup>554</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>555</sup> 86 FR 63177.

<sup>556</sup> <https://echo.epa.gov/report-environmental-violations>.

that the EPA does not cite any information that this system is lacking or not capable of meeting the purpose for which it was established. To the extent that members of the public believe that there are not enough resources being allocated to processing allegations of environmental violations, the commenter recommends that additional resources be provided to support that issue before considering deputizing members of the general public.

First, the commenter (0831-AXPC) asserts that there are potential safety concerns associated with members of the public accessing sites without proper notice, personal protection equipment (PPE), and training. For example some sites can contain hydrogen sulfide (H<sub>2</sub>S), a gas that could result in series health issues for members of the public without proper protection. Second, that suggest that well sites located on private property and providing this authority could encourage members of the public to trespass onto private property and to avoid safety signs and considerations. The commenter states that this could result in members of the public hurting themselves or damaging equipment that could result in putting workers in danger. They add that there is also the question of who would be liable for the safety for the members of the public who illegally trespass on the property or for any damage that they may cause.

Third, the commenter (0831-AXPC) notes that other members of the public may be confused or misled by claims of significant unauthorized emissions from well sites by citizens. As members of the public are not aware of permitted activities or where exactly a source of emissions may stem from, the commenter is concerned that they could unintentionally raise alarm to other members of the public unnecessarily.

Fourth, the commenter (0831-AXPC) suggests that, as citizens are not necessarily aware of activities that are permitted or all other potential sources of emissions around the wellsite, there is a high likelihood that this will result in EPA and companies having to chase ghost emissions – *i.e.*, those emissions that are not violations of any permit as they are either permitted activities or not from the wellsite – thus preventing EPA from enforcing actual environmental violations and causing unnecessary burden and harm on companies.

Fifth, the commenter (0831-AXPC) states that if information is gathered from members of the public, there is no clear chain of custody on the information to ensure that it is valid and has not been modified. As this information may be used in enforcement proceedings that could result in significant fines, the commenter notes that it is unclear how EPA and the owners of the site can ensure that the information is valid.

Sixth, the commenter (0831-AXPC) recommends that, while AXPC has raised concerns with the requirements around Appendix K above, if EPA wishes to move forward with this action, members of the public should be held to the same training and accuracy requirements as operators, as it does not make sense that EPA should not require the same standards for citizen inspections as it does for industry compliance.

Finally, the commenter (0831-AXPC) is generally concerned about the location of such a significant potential policy change. According to the commenter, this type of action has broad implications to all other sectors regulated under the CAA, as well as potentially to other environmental laws under EPA's purview. Due to the broad implications and potential

applications, the commenter recommends that if EPA believes that this is appropriate to move forward with, that EPA do this through a different rulemaking activity such that all members of the public, included all other potentially regulated industries, are able to comment and consider the potential impacts of this action.

Commenter (0941-350 Silicon Valley) states that the forthcoming supplemental rule must include requirements for the EPA to offer training to frontline communities in how to monitor and report local pollution. The commenter indicates that their participation in fenceline monitoring or sensor equipped vehicle monitoring could assist in pinpointing super emitting sources in problematic areas identified by satellites. The commenter adds that EPA should be required to log community complaints about air quality as well as excessive bright lights and noise from nighttime flaring. The commenter notes that instruction in how to generate data that is both reliable and acceptable is necessary. The commenter asserts that if valid information is presented by communities, nearby facilities must be required to investigate and mitigate if they are not complying with legal standards.

Commenter (0828-UCS) states that to further ensure that impacted communities are afforded a voice in the implementation of this rule, EPA must provide pathways for actionable responses to community-based data collection and leak identification efforts.

Commenter (0833-UTE EPD) believes that empowering communities impacted by oil and natural gas development is important. The commenter recognizes that there are opportunities to provide communities with resources, training, and support to use sensor technology, and monitors to use as a screening tool for potential leaks or malfunctions, and in addition, hiring technically trained support. For example, the commenter provides that the supplemental proposal could require sources to provide resources to locate passive benzene (similar to those used around petroleum refineries) monitors in neighboring communities. These monitors can indicate the presence of emissions and OGI monitoring then can be used to identify leaks and institute repairs. The commenter also suggests that community organizations can collect and replace monitors, and ship to the lab for processing. They add that the community can then notify the implementing authority and the source that emissions are present. According to the commenter, by allowing the community to be involved there would be more trust in the data and confidence that issues are being identified and addressed.

Commenter (0833-UTE EPD) also believes that an anonymous emissions/malfunction hotline can be made available to workers and community members to report issues when they occur. The commenter suggests that EPA require a root cause analysis and corrective actions when a community member or organization discovers and reports a large emission event. The commenter recommends that this include, at a minimum, a response from the source's owner/operator documenting what investigation was performed, what was discovered, and what corrective actions were taken.

Commenter (0833-UTE EPD) also advocates for an interactive emissions mapping tool for community members to understand the location and potential emissions from the oil and natural gas industry subject to the rules, as well as the location for abandoned and orphaned wells. The commenter recommends that this interactive tool be flexible enough for communities

to add potential new leases and permits for new or modified sources so they can effectively engage in future activities. They add that this tool should also include up-to-date information on the sources' owner/operator, so that the community members can quickly notify the facility of large emission events.

Response I-7-232: The EPA acknowledges supportive comments, concerns around safety and community engagement, and remarks regarding the need to finalize framework for detecting and reporting large emissions events.

In the November 2021 proposal, the EPA solicited comment on the use of information collected by communities and others to address large emissions events, which the December 2022 Supplemental Proposal defined as “super-emitter emissions events.” The EPA did not propose any standards in the November 2021 Proposal but did so in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>557</sup> Please see section X.C of the preamble to the final rule which details EPA’s final standards related to the super emitter program, which describes the qualifications entities must meet to apply to become approved third-party notifier of super-emitter events.

Comment: Commenter (0924-U.S. Small Business Administration (SBA)) state small businesses have expressed significant concern that these third parties will be held to a less stringent standard for operation of the technology and interpretation of the results. They fear that giving third parties the ability to trigger such actions without quality checks and minimum competency standards will lead to a cycle of unnecessary and duplicative monitoring and remediation exercises. Any third-party use of a monitoring technology that can trigger regulatory action should meet the same standards to which the regulated entities are held, including EPA’s proposed Appendix K.

Response I-7-233: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>558</sup> Please see section X.C of the preamble to the final rule which details EPA’s final standards related to becoming a certified third-party notifier, as well as rigorous requirements for detailing the procedures and processes to ensure the data collected is in compliance with the requirements of the rule when submitting notifications of super-emitter events.

Comment: Commenter (1422-Senator Marshall *et al.*) suggests that EPA’s desire to implement a community monitoring program to detect large emission events is troubling. The commenter requests that this regulatory approach be abandoned; however, if EPA is insistent on pursuing this course of action, they state it is vital that the program be carefully crafted to ensure protections from overzealous activists seeking to induce financial hardship on producers with false reports. The commenter notes that the proposed rule states that EPA “generally envision[s] a program for finding large emission events that consists of a requirement that, if emissions are detected above a defined threshold by a community, a Federal or State agency, or any other third party, the owner or operator would be required to investigate the event, do a root cause analysis,

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<sup>557</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>558</sup> 87 FR 74746-74755 (December 6, 2022).

and take appropriate action to mitigate the emissions, and maintain records and report on such events.” The commenter recommends that, if EPA intends to force expensive compliance costs on producers based on the analysis of “any other third party,” it is vital to set very high standards for what constitutes credible data. They state that there must be training requirements for submitting parties, and producers need to be given adequate time to complete any required compliance actions after notification.

Response I-7-234: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>559</sup> Please see section X.C of the preamble to the final rule which details EPA’s final standards related to third-party notifier certification, which includes requirements for detailing the procedures and processes to ensure the data collected is in compliance with the requirements of the rule when submitting notifications of super-emitter events.

Comment: Commenter (0824-WDEQ) has significant concerns regarding EPA’s suggested community program, which creates a number of quandaries for state agencies regarding data submissions, emissions inventories, and monitoring programs, and regulatory actions that may need to be undertaken by the commenter. The commenter states that it is not clear from EPA’s November 2021 Proposal whether the legal basis for such an approach falls within the bounds of NSPS.

The commenter (0824-WDEQ) questions the fundamental basis for creating this additional regulatory requirement. In accordance with Wyoming’s Environmental Quality Act<sup>560</sup>, the commenter has a well-established, well-functioning complaint process through which third parties and members of the general public can report any pollutant emission event of concern - regardless of whether it is a large scale or small scale event -and the agency’s compliance program promptly handles inspections and correspondence with the operator to investigate the situation, and if an issue is discovered, to address it. The requirement in the proposed rule that data gathered by third parties triggers and mandates specific state processes only convolutes the process and diverts the commenter’s resources from providing a more-immediate follow-up to correct the issue, as well as from undertaking other important work.

Commenter (0824-WDEQ) reports that the current state of methane and VOC ambient detection technology is not accurate enough to quantify a leak without extensive modeling to link the ambient detection to a specific leak. There would need to be extensive technical work performed by operators or the state agency to quantify a leak from a detection at a community monitor. This work would include methane background, other methane sources in the area, meteorological monitoring, and pollution transport modeling to determine if a leak meets a threshold. The commenter raises concerns that the threshold could be lowered to a degree where the consideration of all third-party data could obfuscate and even invalidate the well-established ambient air quality monitoring practices and protocols that state agencies must follow under federal law (e.g., 40 CFR part 58). Furthermore, a lowered threshold could result in an unending labyrinth of data. Also, setting a lower threshold for the collection and submission of third-party

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<sup>559</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>560</sup> W.S. §§ 35-11-101 et seq.

data could result in a scenario where the goalposts are continuously moved in the future. This would result in additional strains on state agency resources, as well as creating further ambiguity regarding which data is most credible.

As an alternative, the commenter (0824-WDEQ) encourages EPA to engage with its state co-regulators to examine existing state frameworks for addressing citizen concerns. State, local, and Tribal air agencies are more accessible to, familiar with, and responsive to their citizens' concerns because they are located in and accountable to those communities.

Commenter (0938-TXOGA) believes that community involvement in large emission events as proposed is too vague and ill-defined to allow for meaningful comment. EPA should treat the November 2021 Proposal as an Advance Notice of Proposed Rulemaking and issue a future proposed rule that includes regulatory language, detailed preamble explanation of the basis for the proposal, and the other elements required under CAA section 307(d)(3) for regulatory proposals to establish a standard of performance under CAA section 111.<sup>561</sup>

The commenter (0938-TXOGA) adds that issues to be addressed in any such proposal would include how these measures would be implemented (*e.g.*, EPA-approved technologies and methods) and the procedural obligations and steps involved (including quality assurance and data validation), on what basis EPA has the authority to expand upon section 304 of the CAA with respect to citizen enforcement by giving direct rights to non-regulators to demand information from facilities, and how EPA would cabin potential abuse of the provision. As the Agency acknowledges,

[I]n order to make this approach viable, the EPA would need to specify what actions an owner or operator must take when notified of a large emission event, including deadlines for taking such actions. These elements could include the specific steps the company would take to investigate the notification and mitigate the event, such as verifying the location of the emissions, conducting ground investigations to identify the specific emission source, conducting a root cause analysis, performing corrective action within a specific timeframe to mitigate the emissions, and preventing ongoing and future chronic or intermittent large emissions from that source.<sup>562</sup>

Commenter (0938-TXOGA) argues these items are not insignificant details and EPA would not be able to issue a final rule based on the current solicitation of comment. Indeed, these are program elements with potentially significant consequences for regulated entities, depending upon how they take shape.

Commenter (0938-TXOGA) states EPA could not (and should not) promulgate a regulation that would require owners or operators to respond to spurious claims that “large emissions events” have occurred at a particular facility. The commenter argues EPA would also need to reconcile its approach with the structure established by Congress under the CAA with respect to the roles of non-regulators, specifically, through participation in the rulemaking process and bringing citizen suits under CAA section 304. The procedural protections and obligations of CAA section

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<sup>561</sup> See CAA § 307(d)(3), 42 U.S.C. § 7607(d).

<sup>562</sup> 86 Fed. Reg. at 63,177.



304 are important elements of the statute that are not appropriate to override with separate citizen enforcement provisions.

The commenter (0938-TXOGA) adds, to the extent EPA is suggesting that citizens could conduct on-site inspections, the CAA does not contemplate citizen inspections akin to those authorized for governmental authorities under section 113, 114, and Title V.<sup>563</sup> Had Congress intended such an approach, it would be explicitly authorized in the statute.<sup>564</sup> The approach could also have unintended adverse impacts that are important to consider. For example, this approach could implicate property rights of site owners and lessees, the safety of untrained community members who may seek to access property in an unsafe manner, and other issues with attempting to “deputize” citizen inspectors.

The commenter (0938-TXOGA) goes further, to the extent that EPA intends to finalize a regulatory provision that would trigger source obligations based upon emissions detected through third-party monitoring, such monitoring must be held to a high and rigorous standard, similar to the monitoring standards proposed for the regulated industry. EPA’s conceptual proposal to create regulatory obligations based upon third-party monitoring is unprecedented and needs to be carefully considered in light of: (1) the scope of EPA’s authority under CAA section 114 to establish monitoring requirements; (2) the scope of EPA’s CAA section 111 authority to establish standards of performance; and (3) constitutional due process considerations that require fair notice of the conduct that can be penalized under an agency’s regulatory program.

Response I-7-235: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>565</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. The final rule includes requirements related to third-party notifier certification, which contains specific requirements related to procedures and processes to ensure the data collected is in compliance with the requirements of the rule when submitting notifications of super-emitter events. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0738-Exxon) notes that while voluntary efforts by individual companies are important, they only capture a fraction of industry’s overall emissions. Full industry participation is required to maximize the benefits to society. Accordingly, based on their experience and expertise, the commenter supports EPA’s November 2021 Proposal to focus attention and effort on the larger emitting sources, and the related proposal to establish volume-based baselines and exemptions rather than production-based exemptions.

The commenter (0738-Exxon) cautions against EPA improperly delegating its enforcement authorities to third parties. Such reporting by third parties should be provided directly to the Agency for evaluation and communication to companies as warranted before any obligations are

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<sup>563</sup> See CAA § 304, 42 U.S.C. § 7604.

<sup>564</sup> See *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302 (2014).

<sup>565</sup> 87 FR 74746-74755 (December 6, 2022).

imposed. Further, the commenter believes that third parties who submit such reports to the Agency must take on some responsibility to ensure sufficient rigor of the data, in the commenter's opinion. The commenter recommends that EPA define approved methodologies, establish quality assurance/quality control standards, and delineate sensible thresholds. Both the Agency and companies should focus their efforts on regulatory enforcement and compliance under the new rules, rather than on potentially unreliable third-party observations.

Response I-7-236: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>566</sup> Please see section X.C of the preamble to the final rule which details EPA's final standards related to third-party notifier certification, which includes rigorous requirements for detailing the procedures and processes to ensure the data collected is in compliance with the requirements of the rule when submitting notifications of super-emitter events.

Comment: Commenter (0727-OSEE/ODEQ) asked if EPA is proposing that a separate, unpermitted emission limit apply to facilities, which communities should use as a benchmark for regulatory action. This aspect of the November 2021 Proposal raises concerns and questions, especially considering the technical complexity of identifying and characterizing emissions, as discussed above. For these reasons, the commenter emphasizes that community involvement in finding large emission events would best work in partnership with the delegated regulatory authority.

Response I-7-237: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>567</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the EPA having a central role in the program as far as verifying the completeness and accuracy of notifications from certified third-parties before sending them to the appropriate owner or operator. The EPA will also have a central role in approving monitoring technologies, certifying and de-certifying notifiers, requiring that third parties submit notifications in a limited timeframe, and obligating operators to subsequently respond in a timely manner. For details, please see section X.C of the preamble to the final rule.

#### ***7.4.2 Framework Recommendations***

Comment: Commenter (0788-350 Seattle) urges the EPA to strengthen its monitoring requirements. In a study of 37 wells on private property in the Permian Basin of Texas, it was found that seven had methane emissions of as much as 132 grams per hour (g/hr). Similarly, a 2016 study of inactive wells in Colorado, Wyoming, Ohio and Utah, found leaking methane

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<sup>566</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>567</sup> 87 FR 74746-74755 (December 6, 2022).

equivalent to burning more than 16 million barrels of oil, according to conservative government estimates.

Commenter (0788-350 Seattle) state, in general, EPA monitoring results underestimate methane quantities. The Gas Index, a 2020 report of 71 cities released by Climate Nexus and developed by Global Energy Monitor, using the newest methane science to estimate leakage from the wellhead to the home, indicates rates far higher than the government's estimates, some more than four times higher.

According to the commenter (0788-350 Seattle), technologies to improve measurement, reporting and verification (MRV) are now available, and their wider use would facilitate identification of "super-emitters." Individual facilities responsible for super emissions of methane frequently have malfunctioning equipment that can be repaired fairly quickly. Basins known for their super emissions of methane can typically be identified by their excessive flaring of natural gas.

The commenter (0788-350 Seattle) believes the November 2021 Proposal fails to address the lack of well-defined systems for measuring and mitigating the emissions of methane in the methane production and distribution system. The November 2021 Proposal points out the episodic nature of super-emitter sites. The commenter argues this implies that emissions monitoring needs to be continuously in place. The commenter states this must be rectified by requiring site specific measurement instrumentation operated by independent third parties to monitor methane emissions continuously with rapid response teams in place, manned by the responsible parties, to react to identified leaks. This would be complemented by data from satellites such as TROPOMI/Sentinel-2, GHGSat, PRISMA, and future MethaneSat and Carbon Mapper.

The commenter (0788-350 Seattle) asserts that emissions being monitored quarterly or semiannually are not acceptable when a large leak could occur at the beginning of a measurement cycle and not be detected or repaired for weeks or months. The "endangerment finding" by the CAA must be applied as an emergency basis for action, and not for continuing business as usual.

Response I-7-238: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>568</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the EPA having a central role in the program as far as verifying the completeness and accuracy of notifications from certified third-parties before sending them to the appropriate owner or operator. The EPA will also have a central role in approving monitoring technologies, certifying and de-certifying notifiers, requiring that third parties submit notifications in a limited timeframe, and obligating

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<sup>568</sup> 87 FR 74746-74755 (December 6, 2022).

operators to subsequently respond in a timely manner. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0944-Kuva) argues that large emission events are much more likely to be found by continuous monitors like C-OGI cameras, then by quarterly or biannual OGI inspections or bi-monthly screening methods. The commenter strongly urges EPA not to require any additional reporting requirements for large emission events, because they would be a big disincentive for the installation of C-OGI cameras. Similar concerns apply for the adoption of bi-monthly screening technologies. A stringent disclosure requirement would cause oil and gas operators to use primarily OGI inspections, as they are less likely to find such large emission events and cause related negative publicity.

As an alternative approach, the commenter (0944-Kuva) proposes for EPA to implement an anonymous reporting program that provides much more detailed information about root-causes, emission duration, intermittency, total amounts, types of equipment, type of site, age of site, *etc.* then is currently required. The purpose of this program is to collect more data about the nature of intermittent emissions, the distribution of large emission events and the effectiveness of continuous monitoring technologies. Such information can subsequently be used for future BSER determinations.

Response I-7-239: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>569</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the EPA having a central role in the program as far as verifying the completeness and accuracy of notifications from certified third-parties before sending them to the appropriate owner or operator. The EPA will also have a central role in approving monitoring technologies, certifying and de-certifying notifiers, requiring that third parties submit notifications in a limited timeframe, and obligating operators to subsequently respond in a timely manner. For details, please see section X.C of the preamble to the final rule.

### ***7.4.3 Super-Emitters/Large Emission Events***

#### ***7.4.3.1 Clarifications Needed***

Comment: Commenter (0727-OSEE/ODEQ) requests clarification on what constitutes a large emission event, *e.g.*, the commenter asked what would define a large emission event without knowing the facility's permit limitations.

Response I-7-240: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>570</sup> Please also see section X.C of the

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<sup>569</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>570</sup> 87 FR 74746-74755 (December 6, 2022).

preamble to the final rule. A super-emitter event is defined as any emissions event that is located at an individual well site, centralized production facility, or compressor station and that is detected using remote detection methods and has quantified emission rate of 100 kg/hr of methane or greater.

Comment: The commenter (0824-WDEQ) notes the November 2021 Proposal's definition of "third party" is ambiguous and requires further clarification and, ultimately, significant refinement. Opening the submission of data to a boundless range of third parties creates the potential that state agencies like the commenter's will be flooded by data of dubious quality. Evaluating the data for quality and usability presents an unworkable strain upon the commenter's emissions inventory, monitoring, and compliance programs.

Response I-7-241: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal, including the required qualifications for notification. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>571</sup> For entities seeking to become third-party notifiers, the final rule stipulates specific requirements on how to apply to the Administrator for approval as a third-party notifier. Please see section X.C of the preamble to the final rule.

#### 7.4.3.2 Satellite Technology Available to Identify Super-Emitters

Comment: Commenter (0826-Kairos Aerospace) is in consensus with EPA that the majority of emissions originate from large emission sources. The commenter cites to several studies that similarly conclude that the majority of methane emissions are the result of emissions from a small number of sources.<sup>572,573,574, 575,576,577</sup> In the commenter's opinion, these findings demonstrate the importance of quickly capturing low probability, high-consequence events through basin-wide surveys. The commenter emphasizes that the Omara *et al.* 2018 study results are of particular note as the data collected by this study inform the commenter's model-based recommendations about the appropriate sensitivity and frequency of advanced leak screening technologies. Thus, the commenter believes EPA should prioritize the detection of super-emitters and allow for the use of aerial technology as an alternative performance standard.

Response I-7-242: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in

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<sup>571</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>572</sup> For example, Chen *et al.* found that 50% of observed emissions from over 90% of New Mexico Permian Basin active wells came from large emission sources with persistence-averaged emission rates over 308 kg/hr.

<sup>573</sup> Chen *et al.* In Revision.

<sup>574</sup> The large meta-study by Omara *et al.* in 2018 found that five percent of sites accounted for 50% of cumulative emissions.

<sup>575</sup> Omara *et al.* 2018.

<sup>576</sup> Robertson *et al.* 2017 found that 72-83% of total measured emissions were from 20% of the well pads surveyed.

<sup>577</sup> EPA TSD citing Robertson, Anna M., Rachel Edie, Dustin Snare, Jeffrey Soltis, Robert A. Field, Matthew D. Burkhart, Clay S. Bell, Daniel Zimmerle, and Shame M. Murphy, "Variation in Methane Emission Rates from Well Pads in Four Oil and Gas Basins with Contrasting Production Volumes and Compositions," *Environmental Science & Technology*, 2017, 51, 15 8832-8840 (June 19, 2017). <https://pubs.acs.org/doi/pdf/10.1021/acs.est.7b00571>. (Hereinafter, "Robertson *et al.* 2017").

section IV.C of the December 2022 Supplemental Proposal.<sup>578</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0738-Exxon) believes that EPA’s focus on very large emissions via satellite detection is a sensible approach, but EPA should review and fully understand the shortcomings of current satellite detection technology. That being said, satellite monitoring is also an area of continuing improvement, as illustrated by the commenter’s recent announcement of working with Scepter, Inc. on satellite detection coupled with data fusion from ground-based and aerial information.<sup>579</sup>

Response I-7-243: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>580</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

Comment: Commenters (0844-EDF *et al.*, 0932-GHGSat, Inc., 0935-Colorado Oil & Gas Association (COGA)) state that leak detection technology continues to improve. Emerging technologies offer several advantages over traditional OGI inspections, most importantly the ability to detect large emission events/super-emitters.

The commenter (0935-COGA) notes numerous research studies have documented the importance of finding and repairing large emission events. EPA compiled an extensive list of dozens of studies regarding the importance of large emission events in its TSD.<sup>581</sup> The commenter supports the comments submitted by Kairos Aerospace. Kairos’ comments include an analysis performed by Highwood showing that aerial surveys can achieve equivalent or greater emission reductions than OGI surveys by quickly detecting LEEs.

Response I-7-244: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>582</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and

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<sup>578</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>579</sup> News Release: ExxonMobil and Scepter, Inc. to deploy satellite technology for real-time methane emissions detection (Dec. 13, 2021).

<sup>580</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>581</sup> EPA “Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)” at 12-43 (October 2021).

<sup>582</sup> 87 FR 74746-74755 (December 6, 2022).

transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0405-Dr. Jonas S. Wilzewski) recommends that the EPA:

1. Retain the flexibility to certify satellite-based systems as valid means of practical emission detection throughout the coming years.
2. Regularly revisit the threshold that defines regulation-relevant methane emission events throughout this decade.
3. Require oil and gas companies to report on maintenance activities that lead to considerable methane emissions.
4. Consider providing wind speed measurements near oil and gas infrastructure sites to the public.

Response I-7-245: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>583</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0927-Interfaith Center on Corporate Responsibility) recognizes that more frequent inspections are effective at identifying super-emitters that by their nature are unpredictable yet are significant sources of leaks. As technology improves, the commenter acknowledges the importance of regulatory flexibility to enable adoption of the most effective (and cost-effective) technologies to manage methane emissions. The commenter urges companies to adopt direct measurement of methane emissions as an effective means of emissions mitigation by helping companies to identify their major sources of emissions, including many not captured by the standard factor-based reporting regime such as super emitters. With an accurate picture of emissions, companies can take steps to cost-effectively address their most significant leaks. It also greatly increases investor confidence in companies' methane emissions data.

Response I-7-246: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>584</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

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<sup>583</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>584</sup> 87 FR 74746-74755 (December 6, 2022).

#### 7.4.3.3 Emissions Threshold

Comment: Commenter (0932-GHGSat, Inc.) reports that with respect to an emissions threshold that could be used to define these large emission events, there are some satellite systems capable of generally identifying emissions above 100 kg/hr with a spatial resolution which could allow identification of emission events from an individual site. Other satellites systems are available which have wider spatial resolution that can identify large methane emission events, and when combined with finer resolution platforms, could allow identification of emission events from an individual site.

Response I-7-247: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>585</sup> Please also see section X.C of the preamble to the final rule. A super-emitter event is defined as any emissions event that is located at an individual well site, centralized production facility, or compressor station and that is detected using remote detection methods and has quantified emission rate of 100 kg/hr of methane or greater.

Comment: The commenter (0932-GHGSat, Inc.) agrees that is relevant to consider methane monitoring by satellites due to the increased survey frequency monitoring for the larger leaks. As stated by Duren *et al.*, detection limits for methane point sources could be relaxed by a factor of ten compared with the survey presented in the research (*i.e.*, aircraft sensor with detection threshold of 10 kg/hr) and still identify 90 percent of super emitters if applied frequently over large areas.<sup>586</sup>

Response I-7-248: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>587</sup> Please see section X.C of the preamble to the final rule which details EPA's final standards for the super emitter program.

#### 7.4.3.4 Flexible/Matrix Approach

Comment: Commenter (0935-COGA) urges EPA to promote the use of innovative technologies by creating flexible frameworks for their use.

Response I-7-249: EPA acknowledges the commenters support for the use of alternative technologies. EPA has taken this comment into account as they designed the alternative technology program in the December 2022 Supplemental Proposal. See discussion in section IV.B of the December 2022 Supplemental Proposal related to advanced methane detection technologies.<sup>588</sup> Please also see section X.B of the preamble to the final rule which details EPA's

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<sup>585</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>586</sup> Duren, et al., 2019.

<sup>587</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>588</sup> 87 FR 74740-74746 (December 6, 2022).



final standards related to advanced methane detection technologies, which includes adoption of flexible frameworks.

Comment: Commenter (0932-GHGSat, Inc.) agrees that prompt action on identifying and ultimately minimizing methane leaks with considerable emission rates is the most cost-effective method to generate immediate environmental, economic, and social impacts. As discussed by Brandt *et al.*, leakage data sets are statistically heavy tailed, with 5 percent of leaks (larger leaks by emission rate) typically contributing over 50 percent of the total leakage volume (Brandt, *et al.*, 2016). Hence, detecting and monitoring for the less frequent large emissions have a greater impact than monitoring for the more frequent and numerous smaller leaks mostly identified by the existing LDAR program requirements.

The commenter (0932-GHGSat, Inc.) agrees with EPA that emissions should be classified or labeled based on a range of emission rates and believes that this classification should contain different bins or ranges and provide different labels. This classification can be very beneficial to the regulated community, and it is in line in how EPA has classified other items (*e.g.*, classification of wells, as proposed in this proposed rule). The commenter suggests the following proposed categorization:

| <b>Emission rate (kg/hr)</b> | <b>Classification</b> | <b>OGI follow-up (days)</b> | <b>Repair – First attempt (days)</b> | <b>Repair – Final attempt (days after first attempt)</b> | <b>Delay of Repair</b> | <b>Root Cause Analysis?</b> |
|------------------------------|-----------------------|-----------------------------|--------------------------------------|----------------------------------------------------------|------------------------|-----------------------------|
| Below 10                     | Process-emitter       | 14                          | 30                                   | 35                                                       | Yes                    | No                          |
| ≥10 to <100                  | Major-emitter         | 14                          | 15                                   | 30                                                       | No                     | Yes                         |
| ≥100 to <1,000               | Super-emitter         | 7                           | 10                                   | 25                                                       | No                     | Yes                         |
| ≥1000                        | Ultra-emitter         | 5                           | 5                                    | 20                                                       | No                     | Yes                         |

The commenter (0932-GHGSat, Inc.) explains that the rationale behind this proposed categorization is based on the fact that large emission events contribute disproportionately to emissions, and therefore, need to be found and repaired as quickly as possible. This classification of emission rates can also be associated with a matrix approach. In this type of approach, the main role of OGI shifts from detection to verification. The commenter believes that a tiered approach can be cost-effective and provide multiple additional benefits to operators, and proposed the following:

| <b>Matrix/Tiered Approach</b> |                            |                                    |                            |                    |
|-------------------------------|----------------------------|------------------------------------|----------------------------|--------------------|
| <b>Tiers</b>                  | <b>Temporal Resolution</b> | <b>Spatial resolution (meters)</b> | <b>Source Localization</b> | <b>Sensitivity</b> |
| Analytics                     | Weekly                     | 1000                               | No                         | Low                |
| Satellites                    | Monthly                    | 25                                 | Yes                        | Medium             |
| Aircraft                      | Bimonthly                  | <1                                 | Yes                        | High               |
| OGI                           | Annual                     | At source                          | Yes                        | High               |

The commenter (0932-GHGSat, Inc.) states an operator can benefit from the tiered approach described by having frequent coverage of all the sites. The analytics tier can provide a weekly resolution by leveraging all the data available to generate insights. With this tier, the operator can develop survey plans and monitor for the ultra-emitters ( $\geq 1,000$  kg/hr). The commenter's analytics platform provides the temporal resolution, generates insights, and cues the commenter's satellites to observe an area of interest defined by the algorithms. The second tier is a targeted methane detection and quantification with the commenter's satellites. The temporal resolution can be defined as monthly, surveying for emissions for super-emitters ( $\geq 100$  to  $< 1,000$  kg/hr). The third tier can be deployed bimonthly, surveying for emissions from major emitters ( $\geq 10$  to  $< 100$  kg/hr). This bimonthly requirement and detection threshold are in line with the proposed rules for alternative monitoring equipment. The fourth tier can be deployed in annual basis or to pinpoint the emission source and verify for successful repairs.

Response I-7-250: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>589</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions, remote-sensing equipment on aircraft, and mobile monitoring platforms. For details, please see section X.C of the preamble to the final rule.

#### 7.4.3.5 Guidelines for credible and actionable data

Comment: Commenter (0824-WDEQ) states it is essential that EPA sets very specific guidelines for credible and actionable data. Current methane and VOC sensor technologies have substantial technical limitations. It is questionable whether current sensors have the detection limits and accuracy to discern methane background from a leak in a downwind community. Extensive work identifying instruments or methods with quantifiable accuracy, precision, and reliability would need to be performed. Additionally, acceptable standards for those quality characteristics must be set along with required quality measures. It seems that credible and actionable data must be collected by sensors or other instruments that meet performance testing similar to 40 CFR part 53 and a documented quality system. Further, data handling provisions must also be covered in these specifications, as well as data collection plans, so interferences from other sources of methane can be minimized.

Response I-7-251: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>590</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. For details, please see section X.C of the preamble to the final rule.

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<sup>589</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>590</sup> 87 FR 74746-74755 (December 6, 2022).

#### 7.4.3.6 Emissions are Underestimated

Comment: The commenter (0844-EDF *et al.*) cites to numerous studies to show that super-emitters and abnormal process emissions are often not well-represented and national inventories often underrepresent emissions from these sources, especially where bottom-up approaches have been used.<sup>591,592,593</sup> Accounting for these emission events can increase inventory estimates by 60-70 percent, underscoring the importance of quickly detecting and fixing major leaks.<sup>594</sup> The commenter provides a figure of Alvarez Synthesis Model Inventory Estimates.<sup>595</sup>

In 2012, the commenter (0844-EDF *et al.*) launched a series of research studies to quantify methane emissions from the U.S. oil and gas supply chain with diverse, measurement-based methodologies.<sup>596</sup> This collaborative work with over one hundred and forty experts from academia, industry, and government has resulted in more than forty peer-reviewed papers. The commenter cites to additional studies performed that conclude that EPA's inventories are underestimating emissions.<sup>597,598,599</sup>

The commenter (0844-EDF *et al.*) states that recent research has found several common characteristics of oil and gas industry methane emissions:

1. Emissions occur across the value chain from well to end use, but are concentrated in the production and gathering segments, including well pads, tank batteries, and gathering compressor stations. The commenter's emission inventory, derived from the Alvarez

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<sup>591</sup> EDF, Methane research series: 16 studies, <https://www.edf.org/climate/methane-research-series-16-studies>.

<sup>592</sup> Lyon et al., Constructing a spatially resolved methane emission inventory for the Barnett Shale region, 49 *Env. Sci. Tech.* 8147–8157 (2015); Zavala-Araiza et al., Reconciling divergent estimates of oil and gas methane emissions, 112 *Proc. Natl. Acad. Sci.* 15597–15602 (2015); Zavala-Araiza et al., Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 *Nat. Comms.* 14012—1421 (2017); Zimmerle et al., Methane emissions from the natural gas transmission and storage system in the United States, 49 *Env. Sci. Tech.* 9374–9383 (2015); Omara et al., Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region, 50 *Env. Sci. Tech.* 2099—2107 (2016); Peischl, J. et al., Quantifying atmospheric methane emissions from Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions, 120 *J. Geo. Res. Atmospheres*, 2119–2139 (2015); Caulton et al., Importance of superemitter natural gas well pads in the Marcellus Shale, 53 *Env. Sci. Tech.* 4747—4754 (2019); Robertson, New Mexico Permian Basin measured well pad methane emissions are a factor of 5—9 times higher than U.S. EPA estimates, 54 *Env. Sci. Tech.* 13926—13934 (2020); Zhang et al., Quantifying methane emissions from the largest oil-producing basin in the United States from space, 6 *Sci. Adv.* 5120 (2020); Lyon et al., Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic, 21 *Atmos. Chem. Phys.* 6605-6626 (2021).

<sup>593</sup> Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 *Nature Comms.* 4715 (2021), <https://www.nature.com/articles/s41467-021-25017-4#citeas>.

<sup>594</sup> Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 *Science* 186 (2018), <https://science.sciencemag.org/content/361/6398/186>.

<sup>595</sup> For an explanation of the methodology used to create this inventory, see EDF, 2019 U.S. Oil & Gas Methane Emissions Estimate, <http://blogs.edf.org/energyexchange/files/2021/04/2019-EDF-CH4-Estimate.pdf>.

<sup>596</sup> See EDF, Methane research series: 16 studies, <https://www.edf.org/climate/methane-research-series-16-studies>.

<sup>597</sup> Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 *Science* 186 (2018), <https://science.sciencemag.org/content/361/6398/186>.

<sup>598</sup> See, e.g., Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 *Nature Comms.* 4715 (2021), <https://www.nature.com/articles/s41467-021-25017-4#citeas>.

<sup>599</sup> IEA, Methane Tracker Database (October 2021), <https://www.iea.org/articles/methane-tracker-database> (summary of inventory estimates).

synthesis model, estimates that production segment fugitive emissions represent nearly 50 percent of all oil and gas sector methane emissions.

2. All oil and gas facility types have a skewed distribution in which 5-10 percent of the highest emitting sites are responsible for about half of total emissions; however, the identity of these high-emitting sites can change with time and is difficult to predict.
3. Low production or marginal wells tend to have lower absolute emissions than high production wells, but much higher loss rates as a percentage of gas production. And because roughly three quarters of all wells are marginal, they cumulatively contribute a substantial fraction of total emissions—up to 50 percent of production sector emissions according to a forthcoming study.<sup>600</sup>
4. Emissions can almost always be mitigated once detected, sometimes with a simple repair to stop a leak, and other times by implementing operational or equipment changes that improve a site's efficiency.

The commenter's (0844-EDF *et al.*) Permian Methane Analysis Project (PermianMAP) uses several peer-reviewed measurement approaches to quantify oil and gas methane emissions in the Permian Basin, the nation's largest oil field, and then posts the emissions data on the public website PermianMAP.org to facilitate mitigation. This project and the associated studies have generated several important findings, which the commenter briefly summarizes here.

The commenter (0844-EDF *et al.*) notes that one study estimates the Permian Basin loss rate is 3.7 percent of gas production, substantially higher than the national average.<sup>601</sup> Another study found a similar loss rate of 3.3 percent in the core production area of the Delaware sub-basin in March 2020 using aircraft and tower-based measurements. The paper reports that the loss rate temporarily dropped to 1.9 percent in April 2020 when oil prices declined, but recovered to prior levels by summer 2020.<sup>602</sup> The authors hypothesize that the Permian Basin typically has a high loss rate because wells are developed faster than the pipelines and compressor stations needed to transport the gas to market. This leads to both high rates of associated gas flaring and abnormal emissions due to gathering systems with inadequate capacity. Therefore, the decline in well development during low oil prices temporarily relieved capacity issues and reduced emissions, bringing the leak rate closer to but still higher than EPA estimates. This study suggests that permanent reductions could be achieved by ensuring adequate gathering infrastructure before permitting new well development.<sup>603</sup>

The commenter (0844-EDF *et al.*) notes Robertson *et al.*, a 2020 paper, determined that New Mexico Permian well pad emissions were five to nine times higher than EPA estimates; complex pads including tanks or compressors had about twenty times higher average emissions than

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<sup>600</sup> EDF, Marginal Well Factsheet (2021), [https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021\\_0.pdf](https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf); Attachment A (Omara AGU Slides 2021).

<sup>601</sup> Zhang *et al.*, Quantifying methane emissions from the largest oil-producing basin in the United States from space, 6 *Sci. Advances* 17 (2020), <https://advances.sciencemag.org/content/6/17/eaaz5120/tab-pdf>.

<sup>602</sup> Lyon *et al.*, Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic, 21 *Atmos. Chem. Phys.* 6605 (2021), <https://acp.copernicus.org/articles/21/6605/2021/>.

<sup>603</sup> See Part IV.XX (associated gas at oil wells).

simple pads with only a wellhead.<sup>604</sup> Finally, Cusworth *et al.* in 2021 used an aerial remote sensing approach to quantify over 1,100 large methane sources in the Permian.<sup>605</sup> In support of previous research, the paper found that both the gathering sector and flares are large sources of emissions. They also assess the intermittency of large sources and determine that, on average, large emission sources are emitting 26 percent of the time.

The commenter (0844-EDF *et al.*) has also assessed flare performance in the Permian with a series of helicopter-based infrared camera surveys showing that approximately 5 percent of large flares are unlit and venting gas at any given time, and another 5 percent have visible slip of methane or other hydrocarbons—meaning the flare is only partially combusting the methane and the rest is escaping to the atmosphere. On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and regulatory standards require. Flares are consequently one of the largest sources of methane in the Permian Basin, and the latest surveys have found even worse performance among smaller, intermittent flares.<sup>606</sup>

The commenter (0844-EDF *et al.*) states the scientific understanding of oil and gas methane emissions has expanded greatly over the last decade and can inform effective regulations for reducing emissions, especially fugitive monitoring programs. First, since emissions can occur across the supply chain regulations must have comprehensive coverage. Second, due to the skewed distribution of emission rates and the intermittency of some large emission events, the speed of detecting and stopping large emission sources is most critical for reducing total emissions—underscoring the importance of frequent monitoring and quick repair timelines. Third, because emissions are often episodic, after a screening approach finds a high emitting site, follow-up surveys must not only look for ongoing leaks, but include a root-cause analysis evaluating equipment and operational issues that could trigger high emission events. For example, an undersized tank control system could cause the tank hatch to intermittently pop open; closing the hatch will temporarily reduce emissions, but the problem will likely recur until the control system is fixed. And finally, smaller sites are disproportionate emitters of methane and should not be exempted from LDAR or other regulatory requirements.

Response I-7-252: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>607</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. For details, please see section X.C of the preamble to the final rule. For details, please see section X.C of the preamble to the final rule.

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<sup>604</sup> Robertson *et al.*, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, 54 *Envtl. Sci. Tech.* 13926 (2020), <https://pubs.acs.org/doi/abs/10.1021/acs.est.0c02927>.

<sup>605</sup> Cusworth *et al.*, Intermittency of Large Methane Emitters in the Permian Basin, *Envtl. Sci. Tech. Letters* \_\_ (2021), <https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173>.

<sup>606</sup> See Attachment B (PermianMAP November 2021 Flyover Results).

<sup>607</sup> 87 FR 74746-74755 (December 6, 2022).

#### ***7.4.4 Follow-Up Action/Root Cause Analysis***

Comment: Commenters (0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-UTE EPD, 0932-GHGSat, Inc., 0943-Sault EPD) support the requirement that the owner/operator perform a root cause analysis to determine why the emissions are present and prevent reoccurrences of the emissions upon detecting emissions from equipment where emissions are not expected to occur, in addition to expeditious corrective action.

The commenter (0932-GHGSat, Inc.) believes that performing and documenting a root cause analysis for each detected methane leak should be part of a quality control/quality assurance process that can be modeled after ISO 140001. Documentation of the corrective action and proposed preventive maintenance should be included for each methane leak. The commenter believes that this documentation should be kept on site and not been part of a periodic report. Instead, the operator should integrate this documentation with the periodic and preventative maintenance program.

Commenter (0941-350 Silicon Valley) states the EPA might identify the sources of methane super emissions documented by TROPOspheric Monitoring Instrument (TROPOMI) using follow up flights by planes equipped with methane sensors, such as certain NASA Jet Propulsion Lab planes, and regional oil and gas field maps of wells, tanks, pipelines and processing plants. This might enable prompt notification so repairs could begin immediately.

Response I-7-253: See section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program. The final program includes specific requirements for qualifications for third-party notifiers, third-party notifier certification, notification of super-emitter events, identification of super-emitter events, and super-emitter event reporting requirements.

Comment: Commenters (0808-API, 0938-TXOGA) express various concerns around the term root cause analysis and request that EPA clarify terminology and requirements in the rule.

The commenter (0808-API) states that the process for assessing the cause of equipment malfunctions and operational upsets should be streamlined with appropriate completion and reporting schedules. The specific term “root cause analysis” has other meanings in various regulations and in the oil and gas industry. The commenter recommends that instead of using the term directly within NSPS OOOOb and EG OOOOc, the commenter suggests the following description be used in its place as it targets what information and action should occur during the analysis:

“Identify the primary cause, and any other contributing cause(s), of a malfunction or operational upset of a control device or the equipment itself.”

The commenter (0808-API) also suggests EPA streamline the recordkeeping and reporting of information related to the assessment.

The commenter (0938-TXOGA) says there are significant challenges in terms of defining the event that would trigger the analysis and would need to ensure that any such analysis is

calibrated to the magnitude of the event/concern. Especially given the remote location of many of these sources, a root cause analysis requirement could be extremely burdensome and impractical to achieve in the time frames that EPA typically requires in other rules for such analyses. In addition, there are numerous methods already in place that work to prevent such events and address them when they occur, indicating that such a requirement is not needed.

Response I-7-254: The EPA understands commenters concerns related to the term “root cause analysis.” The final rule uses the term “investigation” in order to minimize any confusion related to the final regulatory requirements for the super emitter program. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program.

Comment: Commenter (0598-CER, 0814-IPAA *et al.*) disagree with EPA’s proposed root cause analysis requirement.

The commenter (0598-CER) believes that conducting a root cause analysis is a business decision and not an activity in which EPA should be investing resources. In the event of a major malfunction, completing a root cause analysis is in the best interest of the operator. The goal of the activity is to investigate, mitigate, and then return the equipment to service without the discovered emissions. Maintaining their assets in good working condition and available for operations is how the commenter generates revenue.

The commenter (0814-IPAA *et al.*) states, introduced in the context of fugitive emission components, EPA introduces and proposes the results of emissions surveys to require a root cause analysis. EPA cites no authority for requiring such analysis by industry. Respectfully the commenter believes their individual member companies are in the best position to determine when a root cause analysis is necessary and what that analysis should entail. Adding additional reporting and recording keeping associated with some vague, undefined concept of “root cause” is as best tangentially related to potentially reducing emissions at some point in the future. Introduction of requirements that address “root cause” are more properly addressed by OSHA and process safety management.

Response I-7-255: The EPA understands commenters concerns related to the term “root cause analysis.” The final rule uses the term “investigation” in order to minimize any confusion related to the final regulatory requirements for the super emitter program. The final rule describes the specific requirements an owner/operator must follow to investigate and to identify the source of the super-emitter event. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program.

Comment: Commenters (0760-Airdar *et al.*, 0780-LongPath) note that for certain root-causes a repair can be implemented remotely, such as change in operational set-points for vapor-recovery units, change in separator cycle timing or other control parameters that can be remotely adjusted. In these cases, a site-visit is not required.

Response I-7-256: The final rule uses the term “investigation” in order to minimize any confusion related to the final regulatory requirements for the super emitter program. The final

rule describes the specific requirements an owner/operator must follow to investigate and to identify the source of the super-emitter event. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program.

Comment: Commenter (0780-LongPath) suggests that for circumstances in which an emission event is not mitigated with the prescribed procedures, the root cause and follow-up steps will need to be reinitiated after a stated number of days or weeks have passed.

Response I-7-257: The final rule describes the specific requirements an owner/operator must follow to investigate to identify the source of the super-emitter event and address cause of the emissions, including the timeline for doing so. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super response program.

Comment: Commenter (0785-John Crane Inc.) recommends a root cause analysis approach which provides 30 days for the operator or owner to complete a root cause analysis of the process where the leak occurs and submit to the EPA a minimum set of information when the root cause analysis is completed. This information should include all identified root causes, planned corrective actions and their costs, expected timeline with a requirement that all actions are completed within six months.

Response I-7-258: The final rule describes the specific requirements an owner/operator must follow to investigate to identify the source of the super-emitter event and address cause of the emissions, including the timeline for doing so. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program.

Comment: Commenter (0760-Airdar *et al.*) reports that another advantage of continuous monitors is the ability to provide some information about the root cause of an emission—to create an AWP where continuous monitors are used for inspection, but OGI surveys are not triggered for events where the continuous monitor provides sufficient data to suggest an OGI survey would not likely be successful. By combining the advantages of continuous monitors regarding both time to detect and root cause analysis, the commenter believes a continuous monitoring AWP can be constructed that is both environmentally and economically beneficial.

Response I-7-259: The final rule describes the specific requirements an owner/operator must follow to investigate to identify the source of the super-emitter event and address cause of the emissions. Please see section X.C of the preamble to the final rule describing the requirements that are being finalized for the super emitter program.

#### **7.4.5 Satellite Technologies**

Comment: Several commenters (0454-Kayros, 0753-IGSD/CHRE, 0785-John Crane Inc., 0844-EDF *et al.*) state that satellites are currently available and additional ones are in development that are capable of remote-sensing methane from oil and gas facilities. Several commenters find that satellite technology is very promising because of its widespread monitoring potential and environmental benefits to its implementation.



Commenter (0844-EDF *et al.*) notes that many methane-sensing satellites currently exist, and still more are in development; these systems are diverse in form and function. Many have very high minimum detection limits and therefore are better suited to detect large plumes and super-emitters rather than to pinpoint emission sources. However, proposed satellites should offer improved sensitivity and thus afford greater precision in locating emission sources.<sup>608,609</sup>

Commenter (0454-Kayros) states the detection threshold for point sources of methane has fallen by an order of magnitude (from 5 tons per hour to less than 500 kg/hr) in the past three years, and the next generation of satellites due to enter service by 2025 may deliver another 10-fold improvement by lowering the threshold to approximately 50 kg/hr of methane. And as the number of monitoring satellites grows, the frequency of observations increases.

Response I-7-260: The EPA acknowledges the commenters' statements regarding the capabilities of satellite methane detection technology.

The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>610</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions as an option for remote detection technology, if approved under the ATM program of the final rule. For details, please see section X.C of the preamble to the final rule.

Comment: Commenters (0454-Kayros, 0785-John Crane Inc., 0844-EDF *et al.*) states although satellite technology is promising, today's technology limits its resolution, sensitivity and scanning scope compared to the wider scan survey approach of aerial aircraft mounted technology.

Commenter (0454-Kayros) states satellite monitoring is more than just a promising technology. Current monitoring systems already provide unprecedented insights into the methane footprint of the energy sector that are based on an extremely robust scientific foundation, which cannot be obtained through other means. The scientific integrity of satellite monitoring as a tool to detect and quantify methane sources is by now well established and beyond doubt. Peer-reviewed research by the commenter and its academic partners shows that super emitters account for 8-12 percent of total emissions from the oil and gas sector. In addition, the commenter estimates that basin-level monitoring captures 90 percent of emissions from the monitored areas.

Commenter (0785-John Crane Inc.) states as a result of satellite's resolution, satellites are adequate when monitoring "super emitters", but must be pre-programmed with asset GPS coordinates. The commenter argues satellite monitoring can be used after initial aerial or ground surveys as an efficient post-remediation lifecycle monitoring medium with negligible incremental costs. Its initial high capital costs can represent a challenge at this early stage of the

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<sup>608</sup> Id.

<sup>609</sup> See, e.g., EDF, MethaneSAT, <https://www.methanesat.org/>.

<sup>610</sup> 87 FR 74746-74755 (December 6, 2022).

technology maturity curve. The commenter believes satellites will play an important role in the future, particularly in the ongoing monitoring of assets.

Commenter (0844-EDF *et al.*) states minimum detection limits of satellites have been estimated to be between 1,000 and 7,100 kg CH<sub>4</sub>/hr.<sup>611</sup> GHGSat has claimed facility-scale detection limits as low as 100 kg/h, but these have not yet been independently verified.<sup>612</sup> Independent efforts using satellites to monitor for super-emitters around the world will help reduce emissions and hold companies accountable. A planned initiative by Carbon Mapper and EDF (MethaneSAT) will provide independent coverage and accountability for regions and producers prone to large methane emission events.

Commenter (0727-OSEE/ODEQ) notes that the use of satellite data as the threshold could be problematic. For example, there could be large emission events that are not visible on satellite due to cloud cover or inadequate timing of satellite imagery for emissions that do not have a constant temporal profile, among other factors.

Response I-7-261: The EPA acknowledges the commenters' statements regarding the capabilities, as well as limitations of satellite methane detection technology.

The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>613</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions as an option for remote detection technology, if approved under the ATM program of the final rule, as well as remote-sensing equipment on aircraft or mobile monitoring platforms. Any of these technologies would be subject to rigorous requirements prior to potential approval under the ATM program. For details, please see section X.C of the preamble to the final rule.

Comment: Commenters (0454-Kayrros, 0753-IGSD/CHRE) state satellite monitoring can support EPA's objectives by helping oil and natural gas companies optimize their methane abatement efforts; by improving the accuracy and trustworthiness of reporting; by involving local communities; and by making it possible to benchmark the methane footprint of U.S. energy against the rest of the world.

Commenters (0753-IGSD/CHRE) encourage the EPA to determine how best to use satellite data, given that the data will become increasingly robust as more satellites are deployed. At minimum, EPA's monitoring system should be able to effectively and quickly incorporate growing data sets in order to best protect the public from hazardous leaks and plumes.

Commenters (0753-IGSD/CHRE) support the EPA's November 2021 Proposal to use satellite and other data to empower communities to participate in identifying and reporting large

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<sup>611</sup> Highwood 2022.

<sup>612</sup> Id.

<sup>613</sup> 87 FR 74746-74755 (December 6, 2022).

emissions events.<sup>614</sup> Such a policy advances environmental justice and would better protect public health and the environment by achieving quicker recognition and abatement of leaks. EPA should work with satellite operators to ensure that data is openly and publicly shared, at no cost to the user, and in a format that is practical and useful for diverse stakeholders. This may include engaging with state agencies and institutions, as well as foreign countries, that collect satellite data and promoting the sharing and harmonization of emissions data.

Response I-7-262: The EPA acknowledges the commenter's statements regarding the capabilities of satellite methane detection technology.

The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>615</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions as an option for remote detection technology, if approved under the ATM program of the final rule. For details, please see section X.C of the preamble to the final rule.

Comment: Commenter (0454-Kayros) provides updates on their success with satellite-based systems, emerging satellite technology, and image processing efforts. The commenter discusses the following key topics in detail below:

1. Current satellite technology provides unique actionable insights.
  - a. Monitoring satellites identify methane super emitters.
  - b. Monitoring satellites measure total methane emissions at the scale of a basin.
  - c. Satellite monitoring complements traditional technologies
2. The credibility of satellite monitoring is well established.
  - a. Field tests.
  - b. Independent verification of satellite detection and quantification.
  - c. Validation of satellite-based basin-level quantification.
3. Satellite monitoring supports EPA objectives.
  - a. Improved accuracy.
  - b. Benchmark U.S. performance versus other countries.

Commenter (0454-Kayros) states satellite-based systems such as the Methane Watch platform developed by Kayros provide broad geographical coverage and can detect super emitter events, often missed by other methods, through a combination of satellites with different capabilities in terms of spatial resolution, frequency of revisit, detection threshold and data bandwidth. The commenter leverages raw data from NASA's Landsat 8, the European Space Agency's Sentinel-2 and Sentinel-5P and other government and commercial satellites through complex AI and machine learning (ML) algorithms to extract precise signals about very large emission events. The commenter states advanced satellite monitoring can also measure methane emissions aggregated at the scale of an oil and natural gas basin. The commenter has implemented

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<sup>614</sup> Proposed Rule at 63,177.

<sup>615</sup> 87 FR 74746-74755 (December 6, 2022).

advanced satellite-based models to quantify emissions from the Permian, Anadarko and Marcellus/Appalachian Basins that account for half of oil and gas production in the U.S.

Commenter (0454-Kayros) adds in the United States alone, the Kayros Methane Watch platform has identified over 500 such events since January 2019, based on satellite data from the TROPOMI instrument aboard Sentinel-5P. Kayros Methane Watch has also detected large numbers of super emitters in other countries.

The commenter focuses much of its R&D efforts on the integration of data and inputs from multiple sensors, including, but not limited to, data from multiple satellite constellations. Much of the recent developments in atmospheric measurements of greenhouse gas emissions have come not only from the availability of new earth-observation sensing instruments, but from advances in image processing and system integration. In December 2020, the European Space Agency acknowledged the satellite monitoring technologies developed by Kayros as “major technical breakthrough”.

The commenter (0454-Kayros) states field tests that consist of controlled releases of a given volume of methane provide further opportunities for validating and calibrating satellite-based monitoring systems. Most recently, Stanford University conducted a series of controlled releases in Arizona and the commenter submitted its measurements as part of a blind test. The results of this exercise will become public in early 2022.

The commenter (0454-Kayros) states several operators in the oil & gas industry have verified satellite observations. Reporters at Bloomberg News with access to the commenter’s monitoring platform have investigated dozens of super emitters by contacting the companies that operate oil and natural gas assets in the vicinity of the locations identified as the likely sources of those emissions. This investigative work has helped create a public record of super emitters confirmed by operators and associated with specific facilities.

The commenter (0454-Kayros) adds independent surveys also have validated satellite observations. For example, an aerial campaign conducted by the Environmental Defense Fund on September 23-25, 2020, identified a super emitter at a gas compressor station in Texas. The commenter’s analysis of the same facility during that period resulted in three separate measurements that were fully consistent with those of the airborne sensor. In addition, further analysis of satellite data indicated that the facility had been releasing large volumes of methane for three months prior to the campaign.

The commenter (0454-Kayros) argues separate studies of methane emissions in the Permian basin, conducted independently by the commenter and EDF using Sentinel-5P data on overlapping periods in 2018-19 estimated total emissions from oil & gas at 2.7 million tons per annum. The fact that two separate teams reached nearly identical results is further validation of the technology.

The commenter (0454-Kayros) goes further, regional inventories based on satellite observations are fully consistent with global inventories from the Intergovernmental Panel on Climate Change. By focusing on average methane concentrations, rather than individual super emitters,

so-called basin inversion models provide a comprehensive measure of total emissions at the scale of an oil and gas basin. These regional inventories can be used to determine the average methane intensity of hydrocarbon production, measured in kilograms of methane per barrel of oil equivalent. Commenter (0454-Kayros) analysis of several basins in the U.S. (Permian, Anadarko, Marcellus), as well as of basins in Kuwait and Turkmenistan yields results that are highly consistent with the country-level estimates of the International Energy Agency.

Commenter (0454-Kayros) believes satellite monitoring can support the objectives of the EPA by increasing the frequency of measurements. Semiannual or quarterly OGI surveys are likely to miss most super-emitters, whereas a satellite-based system with a weekly frequency of observation will provide a more effective coverage.

Commenter (0454-Kayros) notes satellite monitoring can improve the accuracy of methane inventories. First, the frequency, volume, and location of super emitters can inform assumptions about emission factors and result in more realistic estimates, particularly for the type of facilities associated with super emitters. Second, total emissions aggregated at the scale of an oil and gas basin make it possible to benchmark emission factors and reflect regional differences in the observed methane intensity of hydrocarbon production. It is critical to reconcile methane inventories based on emissions factors with atmospheric observations. Monitoring satellites provide a comprehensive view of methane emissions at the scale of an oil and gas basin, and this provides a benchmark against which to calibrate emission factors. For some facilities, emission factors could be phased out altogether in favor of direct measurements.

Commenter (0454-Kayros) notes methane inventories, and reduction targets by extension, should be based on basin-level measurements rather than emission factors. It is equally important to define methane reduction targets against the correct baseline. Monitoring satellites and other types of atmospheric observations are likely to result in an upward revision to the methane footprint of the oil and gas industry. EPA should consider this scenario when proposing mitigation targets.

The commenter (0454-Kayros) states a further benefit of satellite monitoring is that it can be applied to other countries and does not need permission, which makes it possible to benchmark and compare the performance of U.S. operators against its peers. This is important to quantify because the range of methane intensities around the world can vary by a factor of 20 across the oil and gas basins analyzed by Kayros. The global context, including indicators of progress toward the Global Methane Pledge, can inform domestic targets and policies.

Commenter (0454-Kayros) states this matters because climate change is a global problem and climate action must be global. The U.S. must be able to monitor the progress of other countries with respect to their sustainability goals and pledges. Satellite monitoring also provides a basis for dialogue with other countries. The raw data from public satellites is available to all stakeholders and is essential to a shared view of methane sources and trends. The International Methane Emissions Observatory is a case in point: By integrating satellite monitoring in its methane rule, EPA will be at the forefront of climate policy.

Response I-7-263: The EPA acknowledges the commenter's statements regarding the capabilities of satellite methane detection technology.

The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>616</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions as an option for remote detection technology, if approved under the ATM program of the final rule. For details, please see section X.C of the preamble to the final rule.

Comment: Commenters (0932-GHGSat, Inc., 0941-350 Silicon Valley) note satellite technology is available with a nominal detection threshold of 100 kg/hr and a pixel resolution of less than 30 meters.<sup>617</sup> For example, two commercial GHGSat satellites with these capabilities are currently orbiting the earth, providing monitoring across the world. Three more GHGSat satellites are scheduled for launch this summer towards the goal of a ten-satellite constellation within two years. This deployment timeline is well aligned with the regulatory impact analysis (RIA) for the proposed regulation, which anticipates a start date in 2023. Any individual satellite can revisit precisely the same orbital track every two weeks. In other words, each satellite can have an opportunity to measure the same geographical point every two weeks; therefore, the time between opportunities effectively halves with the addition of each satellite. Having a constellation of this size, coupled with aircraft campaigns and data analytics, effectively provides a tiered system for monitoring methane leaks of significance.

The commenter (0941-350 Silicon Valley) adds the EDF's MethaneSAT is scheduled for launch this October and two Carbon Mapper satellites for 2023. Methane SAT's instruments will be able to detect methane at concentrations of 2 to 3 parts per billion with resolutions of about 100 meters by 400 meters. They will also be able to do "inversions" which will indicate where methane plumes originated. Carbon Mapper's two satellites will carry sensors with resolutions of 30 meters square, enabling them to identify point source polluters. So, by 2024 EPA should have sufficient satellite data to quickly identify not only individual facilities responsible for super emissions, but those responsible for smaller, persistent emissions.

Response I-7-264: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.C of the December 2022 Supplemental Proposal.<sup>618</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. This includes the use of satellite detection of methane emissions as an option for remote detection technology, if approved under

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<sup>616</sup> 87 FR 74746-74755 (December 6, 2022).

<sup>617</sup> Esparza, et al., 2021.

<sup>618</sup> 87 FR 74746-74755 (December 6, 2022).

the ATM program of the final rule. For details, please see section X.C of the preamble to the final rule.

#### **7.4.6 Other Recommendations**

Comment: Commenters (0801-Carbon Mapper/RMI, 0807-BP) provide recommendations on how to integrate third-party reports of large emission events.

Commenter (0801-Carbon Mapper/RMI) recommends that EPA establish a U.S. Methane Data Analysis Center (MDAC)<sup>619</sup> and workflow for responding to reports by communities and other third parties of potential larger emission events, defined as so-called “super-emitters” with the potential for emission rates exceeding 100 kg/hr due to leaks, malfunctions or excessive venting. The commenter also recommends that EPA evaluate the broader co-benefits that a third-party reporting program might provide to other programs within EPA and other agencies.

Commenter (0807-BP) encourages EPA to consider, and take comment on, the potential role that third-party certification organizations and technology vendors can play in the verification process. EPA already follows this approach in closely related contexts. For example, third-party organizations like the National Physical Laboratory confirm that FLIR OGI cameras can image gas at the required NSPS OOOOa concentration and flow rates. Similarly here, EPA could allow operators to rely on third-party certification organizations and technology vendors to demonstrate that their technology meets the alternative screening standard requirements.

The commenter (0807-BP) adds, EPA could streamline the verification process by maintaining a regularly updated list of approved technologies. With only a few proven methane technology vendors in the market today, companies may find themselves duplicating efforts in demonstrating and verifying compliance. As proposed, each individual operator would have to undertake the process of verifying their advanced screening technology for compliance, even if the technology has already been verified for use by another operator.

The commenter (0807-BP) states by maintaining a list of approved technologies, EPA could reduce these duplicative efforts. EPA currently does this for other control devices subject to NSPS OOOOa by maintaining a list of control devices where “manufacturers have demonstrated compliance with the testing requirements, including achieving a destruction efficiency of at least 95 percent.” EPA could maintain a similar list, posted on its website, for approved technologies that meet methane detection thresholds. To expedite the use of advanced methane technologies and to make alternative screening more widely available, the commenter recommends that EPA consider pre-verifying existing, proven technologies that meet the standard in advance of the rule’s compliance deadlines.

Response I-7-265: The EPA proposed specific requirements for the super-emitter response program in the December 2022 Supplemental Proposal. For details, please see discussion in

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<sup>619</sup> The MDAC could be implemented as a single new EPA center, by the EPA regional offices, non-profit cooperative institutions funded jointly by EPA and other federal and state agencies, or a federation of third-party organizations certified under an EPA-specified protocol.

section IV.C of the December 2022 Supplemental Proposal.<sup>620</sup> The EPA is finalizing a revised structure of the super emitter program targeted to identify large emission events. The final requirements ensure that the program operates with a high degree of accuracy, integrity, and transparency, necessary for addressing super-emitter events. Please see section X.C of the preamble to the final rule which details EPA's final standards related to third-party notifier certification, which includes requirements for detailing the procedures and processes to ensure the data collected is in compliance with the requirements of the rule when submitting notifications of super-emitter events. Additionally, EPA has separated the review process for the technologies used to report super-emitter events from the third-party notifiers. Technologies will be approved by EPA under the advanced methane detection technology program in 40 CFR 60.5398b(d) and, once approved, posted to EPA's website.

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<sup>620</sup> 87 FR 74746-74755 (December 6, 2022).



## Chapter 8. Fugitive Emissions Components at Compressor Stations

### 8.1 General Support

Comment: Commenter (1267-California Office of the Attorney General (CA AG) *et al.*) supports EPA's adoption of a presumptive standard for compressor stations in the EG OOOOc that follows the same fugitive monitoring and repair program as for new sources.

Response I-8-1: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

### 8.2 Monitoring Frequency/Subcategorization

#### 8.2.1 Cost-effectiveness of Monitoring

Comment: Commenter (0844-Environmental Defense Fund (EDF) *et al.*) suggests that EPA should increase the monitoring frequency for fugitive emissions components located at compressor stations from the proposed quarterly monitoring to either monthly or bimonthly monitoring and states that any subcategorization based on throughput for the compressor station is not warranted.

The commenter (0844-EDF *et al.*) supports their position by stating that compressor station fugitive emissions are significant, particularly gathering and boosting compressor stations. The commenter provides that research has found “that CH<sub>4</sub> emissions from gathering are substantially higher than the current EPA GHGI [Greenhouse Gas Inventory] estimate and are equivalent to 30 percent of the total net CH<sub>4</sub> emissions in the natural gas systems [2014] GHGI,” with the majority coming from gathering facilities.<sup>1</sup> Another more recent study found that combustion slip from compressor engines was the single greatest source of emissions at gathering stations.<sup>2</sup> The commenter notes that the study report<sup>3</sup> states, “Because throughput was a direct function of operating compressors, and 82 percent of compressors in the field campaign were operating at time of measurement, combustion slip was the single strongest driver of the relationship between station throughput and total methane emissions.” To evaluate emissions and reductions from fugitive emissions monitoring and repair at compressor stations, the commenter states that EPA relied on a model plant analysis. The commenter notes using model plants greatly underestimates actual emissions because the analysis does not account for super-emitter events.<sup>4</sup>

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<sup>1</sup> Marchese et al., Methane Emissions from United States Natural Gas Gathering and Processing, 49 Env. Sci. Tech. 10718 (2015), <https://pubs.acs.org/doi/pdf/10.1021/acs.est.5b02275>.

<sup>2</sup> Zimmerle et al, Methane Emissions from Gathering Compressor Stations in the U.S., (2020) <https://pubs.acs.org/doi/pdf/10.1021/acs.est.0c00516>.

<sup>3</sup> *Id.*

<sup>4</sup> 2018 Comments at 109-

[https://www.edf.org/sites/default/files/content/Joint\\_Environmental\\_Comments\\_on\\_EPAs\\_Proposed\\_NSPS\\_Reconsideration.pdf](https://www.edf.org/sites/default/files/content/Joint_Environmental_Comments_on_EPAs_Proposed_NSPS_Reconsideration.pdf).

In addition, the commenter (0844-EDF *et al.*) notes that EPA found the weighted average for single pollutant cost-effectiveness of monitoring at compressor stations (without gas savings) to be \$855/ton of methane for quarterly inspections and \$1,807/ton for monthly inspections.<sup>5</sup> On a multipollutant basis, these values drop to \$428 and \$903, respectively.<sup>6</sup> In 2016, the commenter states that EPA considered values as high as \$2,185/ton to be cost-effective for methane reductions. Thus, the commenter suggests that, because the weighted average, even without gas savings, is well within EPA's traditional cost-effectiveness range and because compressor stations are significant sources of fugitive emissions, EPA should increase the required monitoring at these sources to monthly. If for some reason EPA concludes that monthly monitoring is not cost-effective for all compressor stations, the commenter believes that EPA should then require bi-monthly inspections for the tier of compressor stations where monthly inspections would exceed EPA's cost-effectiveness threshold.

In the commenter's opinion (0844-EDF *et al.*), in analyzing monitoring costs at compressor stations, EPA has likely (and significantly) overestimated the cost per optical gas imaging (OGI) survey by assuming each survey will take between 10.6 and 28.1 hours.<sup>7</sup> The commenter reports that an analysis conducted by MJ Bradley of Air Emission Reports submitted to EPA by oil and gas companies shows that an average compressor station leak detection and repair (LDAR) survey takes just 2.8 hours.<sup>8</sup> Based on this, the commenter believes that EPA's assumed OGI survey costs for compressor stations are likely too high. Additionally, the commenter believes that the double-counting and overestimating of various cost components described earlier in this section also apply to EPA's estimates for compressor stations. Because of these overestimates, the commenter believes that EPA should revise its cost-effectiveness numbers for compressor stations too.

The commenter (0844-EDF *et al.*) emphasizes that EPA should revisit its repair cost assumptions for compressor stations to ensure it is not double counting costs that should be or already are attributed to other work practice standards, like those for reciprocating and centrifugal compressors. The commenter states that, if an operator discovers that a compressor is malfunctioning through an OGI survey, that repair cost is properly attributed to the underlying compressor standards that require operators to have functioning compressors that operate without significant combustion slip.

In the paragraphs below, the commenter (0844-EDF *et al.*) summarizes EPA's cost-effectiveness findings for different classes of compressor stations. The commenter states that these data reveal that monthly monitoring requirements are appropriate for each kind of facility, notwithstanding that they are overestimates of costs.

***Gathering and Boosting Compressor Stations.*** For quarterly monitoring at gathering and boosting compressor stations, the cost per ton of methane reduced is \$1,006 and with gas

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<sup>5</sup> November 2021 Proposal TSD at 12-40.

<sup>6</sup> November 2021 Proposal TSD at 12-41.

<sup>7</sup> November 2021 Proposal TSD at 12-19, 12-20.

<sup>8</sup> Attachment C to the comment, available at EPA-HQ-OAR-2021-3017-2433; <https://cfpub.epa.gov/webfire/>.

savings considered, the cost per ton of methane reduced is \$824. For monthly monitoring, the cost per ton of methane reduced is \$2,219 and if gas savings are considered, the cost per ton of methane reduced is \$2,038.

**Transmission Compressor Stations.** For quarterly monitoring, the cost per ton of methane reduced is \$617. For monthly monitoring, the cost per ton of methane reduced is \$2,219 and if gas savings are considered, the cost per ton of methane reduced is \$2,021. Transmission facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted as the result of equipment leaks was not further analyzed for this segment.

**Storage Compressor Stations.** For quarterly monitoring, the cost per ton of methane reduced is \$211. For monthly monitoring at storage compressor stations, the cost per ton of methane reduced is \$1,094. Once again, storage facilities do not own the natural gas; therefore, revenues from reducing the amount of natural gas emitted as the result of equipment leaks was not estimated for this segment.

The commenter (0844-EDF *et al.*) contends that monthly monitoring at all compressor stations is within the range EPA considers cost-effective. Even ignoring cost savings, the commenter notes that the cost for monthly inspections at gathering and boosting and transmission compressor stations – \$2,219 – is only slightly higher than values that EPA has in the past found cost-effective (\$2,185). Adjusted for inflation, the commenter notes that the \$2,219 value may even be lower than \$2,185. And they add that many other available estimates of costs suggest that monthly monitoring is even cheaper and more cost-effective than EPA’s analysis indicates.

According to commenter (0844-EDF *et al.*), EPA justifies its selection of quarterly rather than monthly monitoring on incremental cost-effectiveness. However, the commenter states that the agency has not explained why incremental cost-effectiveness should matter more than overall cost-effectiveness, nor has it examined whether bi-monthly (six times per year) monitoring might be incrementally cost-effective. Furthermore, the commenters adds, if emissions from super-emitters are considered, monthly monitoring will be far more effective at reducing emissions and more incrementally cost-effective as well. In Colorado’s most recent rulemaking, the commenter reports that the Air Pollution Control Division estimated the cost-effectiveness of quarterly inspections at compressor stations to be \$3,279.14 per ton VOC and \$46.04 per mtCO<sub>2e</sub>, without incorporating the estimated annual value of recovered gas.<sup>9</sup> With gas savings, the commenter reports that the numbers fell to \$2,659.55 and \$37.63, respectively. The commenter adds that New Mexico also recently evaluated the cost-effectiveness of quarterly OGI at compressor stations and estimated a value of \$3,331/ton VOC. According to the commenter, these VOC-designated costs are considerably lower than the level that EPA has identified in the November 2021 Proposal for determining the cost-effectiveness of VOC controls. Likewise, the commenter states that the CO<sub>2e</sub>-designated costs values are markedly lower than the central 2022 values

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<sup>9</sup> Colorado Air Pollution Control Division, Revised Final Economic Impact Analysis for Regulation 7 & 22 Revisions at 17-18 (December 2021), [https://drive.google.com/drive/folders/1mDU8Wc3iB\\_E4lj36R8AK\\_y8ptcU83Yao](https://drive.google.com/drive/folders/1mDU8Wc3iB_E4lj36R8AK_y8ptcU83Yao).

reported in the Interagency Working Group's Interim Global Social Cost of Carbon Technical Support Document (TSD).<sup>10</sup> As noted above, the commenter notes that the Interagency Working Group's values represent a highly conservative estimate of the true social cost of greenhouse gases, and any compliance costs falling below those figures should certainly be considered cost-effective.

Response I-8-2: Regarding the frequency and cost-effectiveness of surveys at compressor stations, EPA received a similar comment on the December 2022 Supplemental Proposal. EPA's response to this comment is provided in Volume II, Chapter 4, section 4.2.1 (Proposed BSER).

Regarding combustion slip from compressor engines, this comment is outside the scope of this rulemaking. Combustion slip is addressed via other regulations, including the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (40 CFR part 63, subpart ZZZZ), New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR part 60, subpart IIII), and New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines (40 CFR part 60, subpart JJJJ).

Consistent with our discussion in section XII.A.b of the November 2021 Proposal preamble, EPA continues to find that the model plant approach is effective for estimating baseline fugitive emissions from compressor stations. Under the final rule, EPA is also establishing a Super Emitter Program separate from the fugitive emission detection and repair program for compressor stations to address super-emitter events. Please see Preamble section X.C which details EPA's final standards related to the Super Emitter Program. Because emissions from super-emitter events at compressor stations are accounted for under the Super Emitter Program, we see no reason that even if they were underestimated by the model plant approach, we would alter our approach to calculating the baseline emissions at compressor stations.

In the November 2021 Proposal, EPA solicited comments on whether compressor stations should be subcategorized, specifically seeking information related to throughputs where fugitive emissions of methane are demonstrated to be minimal below a certain capacity. Because EPA did not receive such information in response to the November 2021 Proposal or December 2022 Supplemental Proposal demonstrating the reasonableness or appropriateness of subcategorization, EPA has not included subcategorization of compressor stations in the final rule.

With regard to the costs associated with OGI surveys of compressor stations, EPA disagrees that the cost estimate is a significant overestimation. Although the estimated times to conduct OGI surveys at different types of compressor stations, ranging between 10.6 and 28.1 hours, are presented in the November 2021 TSD, the cost for a compressor station OGI survey is not calculated based on an hourly rate. Instead, the \$2,492 cost is on a per-survey basis and is

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<sup>10</sup> Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, Table A-1: Annual SC-CO<sub>2</sub>, 2020 – 2050 (February 2021).

derived from Appendix 1 in the Carbon Limits Report CL-13-27, Quantifying Cost-effectiveness of Systemic Leak Detection and Repair Programs Using Infrared Cameras (March 2014), updated to \$2019. As such, EPA did not overestimate cost based on an overestimation of survey time because the cost estimation was independent of survey time.

With regard to double-counting and overestimating of various cost components described earlier in this section, EPA takes this to mean the use of API cost data for reporting, recordkeeping, and data management as described in section 7.1.7 of the 2021 RTC. Because EPA did not use an hourly labor rate for OGI camera surveys for or travel to compressor stations and the rate used specifically excluded any internal administrative costs, EPA does not believe that it double counted recordkeeping and reporting or travel time costs. EPA also believes that the use of average values for recordkeeping costs instead of the weighted average values suggested by the commenter are appropriate because no specific recordkeeping or data management system is required by the rule, so the proportion of facilities using any specific system is subject to change.

Regarding not attributing costs of malfunctioning compressors to fugitive emissions monitoring and repair costs, EPA does not believe that we have done so and the commenter offered no place in the calculation demonstrating such attribution.

### ***8.2.2 Monitoring Frequency***

Comment: Commenter (0744-New York State Department of Environmental Conservation (NYSDEC)) supports EPA's requirements for quarterly LDAR for gathering and boosting stations but would recommend requiring more frequent LDAR for compressor stations. In the commenter's rulemaking for this sector, New York compression station operators will be subject to bimonthly LDAR requirements based on a determination that bimonthly LDAR would be cost-effective and result in more meaningful reductions in fugitive emissions.

Response I-8-3: We understand that "LDAR" refers to the fugitive emission detection and repair program. In response to comments received on the November 2021 Proposal, EPA proposed additional monthly AVO monitoring and repair requirements for compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.2.a of the December 2022 Supplemental Proposal.<sup>11</sup> Regarding the frequency and cost-effectiveness of surveys at compressor stations, EPA received a similar comment on the December 2022 Supplemental Proposal. EPA's response to this comment is provided in Volume II, Chapter, 4, section 4.2.1 (Proposed BSER).

Comment: Commenter (0755-Texas Pipeline Association (TPA)) contends that a requirement for more frequent monitoring than semiannually would be unduly burdensome, given that one pipeline system could have numerous compressor stations that are often located in remote areas. In addition, the commenter states that the resources (both personnel and equipment) to comply with survey requirements may be limited, a concern that EPA itself acknowledged in the

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<sup>11</sup> See 87 FR 74739 (December 6, 2022).

preamble for the initial NSPS OOOOa proposal.<sup>12</sup> Moreover, the commenter notes that the leak rate in the gathering and boosting industry segment is particularly low.<sup>13</sup>

The commenter (0755-TPA) suggests that including prescriptive monitoring requirements are unnecessary and would unduly burden regulated parties with little environmental benefit. As recently as September 2020, the commenter states that EPA concluded that semiannual monitoring was sufficient. The commenter does not believe that little more than a year later, EPA has uncovered a sufficient basis to reject that conclusion and to cut in half the required monitoring interval. The commenter urges EPA to retain the current requirement of semiannual monitoring for fugitive emissions at compressor stations, including gathering and boosting compressor stations.

Response I-8-4: EPA disagrees with the commenter's suggestion that semiannual monitoring for fugitive emissions at compressor stations is appropriate. Consistent with the November 2021 Proposal, EPA proposed to retain quarterly OGI monitoring for compressor stations in the December 2022 Supplemental Proposal. As discussed in the November 2021 Proposal, quarterly OGI monitoring was determined to be the best system of emissions reduction (BSER) for reducing methane and VOC emissions from all compressor stations, including gathering and boosting stations, transmission stations, and storage stations because it produced significant, cost-effective emissions reductions.<sup>14</sup> Consistent with that determination, EPA is retaining quarterly monitoring. In addition, in the December 2022 Supplemental Proposal, EPA proposed to add a requirement to conduct monthly AVO monitoring at compressor stations and any fugitive emissions detected via AVO would be subject to repair, noting that the comments on the November 2021 Proposal indicated that compressor stations are visited on a weekly, if not daily, basis. Please also see section X.A.2 of the preamble of the final rule which details EPA's final standards related to compressor station fugitive emissions. As discussed in section X.A.2 of the November 2021 Proposal, EPA acknowledged in the 2020 Technical Rule that the costs for quarterly monitoring of compressor stations were considered reasonable.<sup>15</sup> EPA instead supported semi-annual monitoring by citing "significant financial hardship" in the industry and asserting that there may be efficiencies and cost savings with applying the same monitoring frequencies for well sites and compressor stations. However, EPA did not offer any data to support the change to semi-annual monitoring. In contrast, compliance records for the 2016 NSPS demonstrate no indication that compressor stations experienced hardship or difficulty in complying with the quarterly monitoring requirement. Further, several state agencies have rules that require quarterly or more frequent monitoring at compressor stations. In addition, EPA received comments in response to the November 2021 Proposal that even compressor stations owned by small companies were visited at least on a weekly basis.<sup>16</sup> EPA finds that AVO monitoring requirements can be conducted by any personnel at the site and disagrees that these

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<sup>12</sup> See 80 FR 56643 (September 18, 2015).

<sup>13</sup> See data collected at EPA-HQ-OAR-2017-0483-0027.

<sup>14</sup> See 86 FR 63194 (November 15, 2021), section XII.A.1.b.

<sup>15</sup> See 86 FR 63159 (November 15, 2021) and 85 FR 57421 (September 15, 2020).

<sup>16</sup> See comments at Document ID Nos. EPA-HQ-OAR-2021-0317-0585 and EPA-HQ-OAR-2021-0317-0814.

requirements are unduly burdensome.<sup>17</sup> The commenter also provided no data to support the assertion that the proposed monitoring requirements would unduly burden regulated parties with little environmental benefit. In contrast, EPA anticipates reasonable costs and significant emissions reductions from compressor stations under this rule.<sup>18</sup>

Comment: Commenter (0817-GPA Midstream Association (GPA)) states that semiannual monitoring at compressor stations provides the most cost-effective system to reduce methane and VOC emissions. (The commenter discussed this in detail in comments submitted on the 2016 and 2020 NSPS OOOOa rulemakings). Once an initial monitoring event occurs at a compressor station, observed leaks and emissions from those leaks remain low. The commenter previously provided sector-specific data to EPA demonstrating a substantially lower leak frequency for the gathering and boosting sector than that assumed by EPA in its TSD documents.<sup>19</sup> The commenter notes that the data set found in Attachment 1 to EPA-HQ-OAR-2017-0483-1261 represents 11 companies and 262 sites across the country. They report that the trend demonstrated by these data is clear: initial leak percentages start low and remain low. Specifically, the commenter's data shows the following:

- *Initial monitoring frequencies:* Across the 11 companies and 262 sites, the average initial leak frequency is 0.24 percent. The data includes both OGI monitoring and EPA Method 21 monitoring. When Method 21 monitored sites are excluded, the initial leak frequency average drops even further to 0.23 percent.
- *Final frequency:* The data also show a clear trend that the leak frequencies start low but reduce further as monitoring continues. Using data from 203 sites, the final leak frequency was 0.17 percent. Facilities that had not performed at least four quarterly monitoring events were not included in the average. The final leak frequency was obtained by averaging the percentage of total leaking components from the last monitoring event where available.

The data that the commenter (0817-GPA) has gathered and presented also clearly show that once the initial survey is performed, leaks from the facilities will remain at low frequencies. Therefore, the commenter states that a semiannual monitoring schedule would reduce burden and cost on industry while still reducing methane and VOC emissions. As shown by Table 12-14a in the November 2021 Proposal TSD, semiannual monitoring provides the lowest cost while still significantly reducing emissions. The commenter states that the November 2021 Proposal never addresses the leak rate data that the commenter provided. In the commenter's opinion, this is a significant oversight given that EPA previously credited that data in the 2020 Technical Rule.<sup>20</sup>

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<sup>17</sup> See 87 FR 74739 (December 6, 2022).

<sup>18</sup> See section XII.A.b in 86 FR 63110 (November 15, 2021) for discussion.

<sup>19</sup> See, e.g., Company Data – Compressor Station Leak Rates – Final, *available at* EPA-HQ-OAR-2017-0483-0027 and Comments Submitted by GPA Midstream *available at* EPA-HQ-OAR-2017-0483-1261. The most recent data set provided by GPA Midstream is included as Attachment 1 to EPA-HQ-OAR-2017-0483-1261.

<sup>20</sup> See 85 FR 57414 and 57418 (September 15, 2020).

Response I-8-5: As discussed in the November 2021 Proposal, EPA evaluated the BSER for compressor stations. EPA analyzed OGI monitoring frequencies ranging between monthly and annual but determined in the November 2021 Proposal that quarterly OGI monitoring was cost effective and that additional emissions reductions could not be achieved at a reasonable cost. Therefore, EPA found in November 2021 based on the cost analysis conducted at that time, that the cost effectiveness of quarterly OGI monitoring for compressor stations is reasonable and determined to be the BSER. The December 2022 Supplemental Proposal analysis was consistent with the November 2021 Proposal determination, and EPA proposed to retain quarterly OGI monitoring for all types of compressor stations. In addition, in the December 2022 Supplemental Proposal, EPA proposed to add a requirement to conduct monthly AVO monitoring at compressor stations and any fugitive emissions detected via AVO would be subject to repair. EPA finds that AVO monitoring requirements can be conducted by any personnel at the site and are not unduly burdensome. EPA agrees that Tables 12-14a in the November 2021 TSD show that semiannual modeling provides the lowest cost per ton of methane or VOC emission reduction; however, EPA also finds that quarterly OGI monitoring is also cost effective in total and incremental costs and provides additional methane and VOC emissions reductions, making it the BSER. In addition, as discussed in the November 2021 Proposal, multiple states have found that quarterly OGI monitoring for compressor stations is cost effective. The leak frequency data provided by the commenter was addressed in the 2020 Policy Rule TSD.<sup>21</sup> In summary, EPA received comments on the 2018 NSPS OOOOa proposal that indicated that the use of the emission factors from Table 2-4 in EPA Equipment Leaks Protocol for components in gas service overestimated fugitive emissions, while other comments provided analyses suggesting that the use of the emission factors underestimated fugitive emissions. After considering submissions by all commenters and analyzing a July 2019 study that measured fugitive emissions from well sites and gathering and boosting stations, EPA determined that the use of the 1995 Protocol factors was still appropriate. EPA finds that the use of these factors is still appropriate for this rule.

### ***8.2.3 Subcategorization***

Comment: Commenter (1291-Cumberland Valley Resources, LLC (CVR)) appreciates that EPA's November 2021 Proposal does not require fugitive emission surveys for wellhead only wellsites and small wellhead compressors under the proposed NSPS OOOOb and EG OOOOc. However, the commenter is afraid EPA has overlooked new problems for small operators caused by NSPS OOOOb where a relatively small compressor associated with another small piece of equipment, such as a dehydrator, makes a small compressor station that would have been exempt under NSPS OOOOa, a centralized production facility that will have to have an LDAR program, expensive quarterly fugitive emission surveys, and the burden of recordkeeping that goes with it.

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<sup>21</sup> See Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa available at EPA-HQ-OAR-2017-0483-2290.



For small companies with legacy wells that would be exempt from NSPS OOOOb and EG OOOOc otherwise, the presence of an old separator or dehydrator becomes a significant burden.

Commenter (1291-CVR) suggests that there needs to be consideration for these numerous small compressor stations that will become centralized production facilities under NSPS OOOOb. With production volumes of 100 to 150 thousand cubic feet per day (Mcf/day), suction pressure of 10 pounds per square inch (psi) and discharge pressures of less than 250 psi, the potential to emit fugitive methane is very small. EPA estimates that compliance costs for a compressor station, whether large and producing 1,000 Mcf/day or a small compressor station like the commenter's producing 100 Mcf/day, is \$13,400 per year. For compressor stations that deliver 100 Mcf/day, that is an additional cost of \$0.372 per Mcf or 11.9 percent of the gross price for our gas, before any other operating costs are deducted. The commenter states that these kinds of costs would be devastating to legacy gas wells. Fields that might otherwise have decades more life would immediately become uneconomical to produce.

Commenter (1291-CVR) makes the following specific recommendations to EPA:

1. Compressor stations that include a compressors and other equipment such as a dehydrator and separator, producing less than 55 MMcf/year (average 150 Mcf per day) and have a maximum discharge pressure of 350 psi, be exempt from NSPS OOOOb regulation, specifically fugitive emission surveys and recordkeeping requirements.
2. Small compressors stations, including those with other equipment such as dehydrators and separator, producing from 55 MMcf/year (an average 150 Mcf/day) to 128 MMcf/year (an average 350 Mcf/day) be allowed a more workable and affordable fugitive emission survey program that would utilize AVO surveys, on a quarterly basis and allow simplified "in house" recordkeeping of the surveys.

Another commenter (0585-Kentucky Oil and Gas Association (KOGA)) believes that EPA is either unaware of or does not understand the impact that the proposed NSPS OOOOb regulations will have on the large number and variety of existing gathering and boosting compressor stations in the gas fields of the Appalachian Basin. According to the commenter, most of the compressor stations are operated by small locally owned companies that meet the definition of a Small Business Entity. Under the 2016 NSPS OOOOb regulations, existing compressor stations were exempt from fugitive emission surveys, but the commenter explains that NSPS OOOOb now proposes to regulate all compressor stations; even small wellhead compressors that were previously exempt. NSPS OOOOb will require small operators to implement expensive fugitive emission surveys and recordkeeping, resulting in little or no reduction of methane emissions.

Commenter (0585-KOGA) states that most of the low volume and low-pressure wells in the Appalachian Basin use a compressor to get their produced gas to market. Most of these wells consist of just a wellhead, which EPA has correctly proposed to exempt from the NSPS OOOOb or EG OOOOc regulations. The commenter explains that compressors used by the small companies are of two types, booster and field compressors. The booster compressors are typically small single stage units with low horsepower drivers connected to a well or groups of low-pressure wells that would not be able to deliver gas into a gathering system without an

external source to increase pressure, the commenter notes. A typical configuration gathers small volumes of gas at very low pressures from groups of legacy oil wells found in many areas of the Appalachian Basin. These wellhead compressors (see Figure 6 of the commenter's letter), which were exempt under the 2016 NSPS OOOOa regulations, typically move around 10 Mcf/d with a suction pressure as low as 0 psi and discharge pressures of between 8 and 20 psi. Because of the pressures at which these compressors operate, they have a very small potential for fugitive emissions and should continue to be exempt from NSPS OOOOb in the commenter's opinion. (See Figure 6 and Figure 7 of the commenter's letter for a Typical Field Booster Compressor and an example Compressor Station with Desiccant Dehydrator.)

The commenter (0585-KOGA) explains that field compressors and the stations where they are located are of almost as many configurations as there are well configurations and include gas compressors and their drivers, and often include dehydration equipment. The operating parameters and designs of compressor stations are dependent on the volume and pressure of gas available from the wells it serves, the pressure of the pipeline the gas is being delivered into, and the water content of the gas moving through it. The larger field compressor stations, which can deliver several hundred Mcf per day into gas gathering systems or transmission pipelines usually include compressors with natural gas fueled engines of 150 to 350 horsepower and include glycol dehydration equipment. The commenter indicates that by far the most prevalent compressor stations operated by the small companies in the Appalachian Basin include compressors that move between 100 and 200 Mcf/day and driven by either electric motors or natural gas fueled engines of 150 horsepower or less. The majority of these size compressor stations only have compressors and their drivers, but glycol or desiccant dehydrators may be required in cases where water content of the gas is high.

The commenter (0585-KOGA) further states that the typical Appalachian Basin small field compressor stations are not large facilities. The commenter notes that these units cannot be compared to the large, high volume and pressure compressor stations and gas processing plants associated with deep unconventional shale gas production of the Marcellus and Utica in Pennsylvania, Ohio and West Virginia, even though EPA is proposing to regulate them as if this was the case. A compressor and driver only station operated by small Appalachian Basin companies, do not have much more plumbing than a typical Appalachian Basin wellhead. The suction side plumbing will be operated at the low suction pressures of the compressor and only a very short distance of discharge plumbing is operated at discharge pressures typically less than 300 psi. As with wellheads, thread leaks or vented gas associated with the brief blowing of a drip tank at a compressor station, are not significant emission sources. The leaks can usually be identified using soap bubbles, and they can easily be corrected with a pipe wrench at the time of inspection. Even though small company compressor stations are not manned 24 hours a day, they are visited weekly, if not daily. According to the commenter, AVO surveys during these frequent visits are far more cost effective for the small companies than quarterly OGI surveys. The commenter explains that leaks do not go unnoticed for any length of time.

The commenter (0585-KOGA) suggests that EPA's estimate of 16 tons per year emissions from these small compressor stations is a dramatic overstatement of methane emissions. The

commenter reports that the Department of Energy methane emissions study, conducted by GSI Environmental Inc. (GSI) and soon to be published, found average methane emissions at the compressors they surveyed in the eastern US of 1.3 kg/day, or less than a half ton per year. The commenter contends that, because of the low suction and discharge pressures at which they are operated, compressors and compressor station equipment typical of small company operations are not large fugitive emission emitters.

Finally, the commenter (0585-KOGA) explains that the fugitive emission surveys of compressor stations using OGI as will be required under NSPS OOOOb, is a service not readily available in their area. The commenter reports that the costs to bring in the equipment necessary from other areas of the country four times a year are prohibitive. The commenter states that EPA estimates that cost to be \$13,400 per year per compressor station. For compressor stations that deliver 100 Mcf per day, that is an additional cost of \$0.372 per Mcf or 11.9 percent of a gross price for gas as estimated by EPA to be \$3.13 before any operating costs. The commenter notes that this is a significant cost for small companies making some gas fields uneconomical to continue to produce. The commenter contends that booster compressors gathering associated gas from oil wells would disappear completely.

Response I-8-6: As stated in EPA's response to comments on amendments to NSPS OOOOa in the 2020 Technical Rule,<sup>22</sup> EPA considers the booster compressors described by these commenters as part of wellsite equipment and not as a separate compressor station, even when located near a well site. A compressor station is defined, in part, as one or more compressors that move natural gas at increased pressures through gathering pipelines. Booster compressors, as described by the commenters, are used to increase the pressure of gas produced from a low pressure well so it can first enter a pipeline. These compressors are integral to the operation of the well site, and as such, are considered part of the well site. Further, as stated in the definition of a compressor station, compressors located at a well site are not considered compressor stations. Therefore, if the well site is subject to fugitive emissions monitoring, then the booster compressor would also be subject to the well site monitoring requirements.

EPA proposed a different regulatory approach for well site fugitive emissions monitoring in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.ii of the December 2022 Supplemental Proposal.<sup>23</sup> Please also see section X.A of the preamble of the final rule which details EPA's final standards related to compressor station and wellsite fugitive emissions.

Comment: Commenter (0787-Atmos Energy Corporation (Atmos), 1289-AEC) recommends subcategorizing compressor stations based upon potential VOC and methane emissions, rather than natural gas throughput. The commenter states that fugitive emissions are estimated using a number of equipment components, assuming that piping components remain in service all year, and are not throughput-dependent.

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<sup>22</sup> See Document ID No. EPA-HQ-OAR-2017-0483-2291, page 8-172.

<sup>23</sup> See 87 FR 74722 (December 6, 2022).

Response I-8-7: In the November 2021 Proposal, EPA solicited comments on whether compressor stations should be subcategorized, specifically seeking information related to throughputs where fugitive emissions of methane are demonstrated to be minimal below a certain capacity. Because EPA did not receive such information, EPA has not included subcategorization of compressor stations in the final rule. Please see section X.A.2 of the preamble of the final rule which details EPA's final standards related to compressor station fugitive emissions.

Comment: Commenter (0923-Lambda Energy Resources, LLC (Lambda)) contends it is overly burdensome to require quarterly monitoring at compressor stations in respect to surveys and recordkeeping. The commenter states that the value of increased monitoring to reduce small amounts of methane and VOCs does not offset the associated expense and manpower required to fulfill the proposed regulations. The commenter suggests that a baseline for compressor stations could be undertaken as a similar proposal for less than 3 tons per year (tpy) well sites to determine future requirements of a particular site. The commenter believes the most feasible and cost-effective solution to accomplish fugitive emission reduction is to undertake periodic AVO inspections and documentation to assess a facility or wellsite for leaks.

Response I-8-8: EPA disagrees that quarterly monitoring at compressor stations is overly burdensome. As discussed in the November 2021 Proposal, EPA evaluated the BSER for compressor stations. EPA analyzed OGI monitoring frequencies ranging between monthly and annual but determined in the November 2021 Proposal that quarterly OGI monitoring was cost effective and that additional emissions reductions could not be achieved at a reasonable cost. Therefore, EPA found in November 2021 based on the cost analysis conducted at that time, that the cost effectiveness of quarterly OGI monitoring for compressor stations is reasonable and determined to be the BSER. The December 2022 Supplemental Proposal analysis was consistent with the November 2021 Proposal determination, and EPA proposed to retain quarterly OGI monitoring for all types of compressor stations and add monthly AVO inspections. The commenter did not provide any additional data demonstrating that quarterly monitoring for compressor stations is overly burdensome. In the November 2021 Proposal, EPA solicited comments on whether compressor stations should be subcategorized, specifically seeking information related to throughputs where fugitive emissions of methane are demonstrated to be minimal below a certain capacity. Because EPA did not receive such information, EPA has not included subcategorization of compressor stations in the final rule. The commenter provided no data to support that periodic AVO alone is the most feasible and cost-effective solution to accomplish emission reductions. Even if periodic AVO alone is feasible and cost-effective, it may not be the BSER for compressor stations because additional monitoring could provide additional cost-effective emissions reductions. Please see section X.A.2 of the preamble of the final rule which details EPA's final standards related to compressor station fugitive emissions.

## 8.3 Delay of Repair/Availability of Parts

### 8.3.1 *Environmental Justice*

Comment: Commenter (1267-CA EG *et al.*) responds to the EPA solicitation of comment on delayed repairs by existing sources when parts are not readily available and must be specially ordered. The commenter recommends that EPA consider disallowing or limiting delayed repairs at facilities close to an environmental justice community.

Response I-8-9: EPA disagrees that delayed repairs should not be allowed or limited at facilities close to an environmental justice community. Unique provisions for facilities close to an environmental justice community would require defining an “environmental justice community” and “close,” which is outside the scope of this rulemaking. The commenter did not provide additional rationale supporting the need for unique provisions for facilities close to an environmental justice community. Please see section X.A.2 of the preamble of the final rule which details EPA’s final standards related to compressor station fugitive emissions.

### 8.3.2 *Allow Delay of Repair*

Comment: Commenter (1391-Interstate Natural Gas Association of America (INGAA)) responds to the EPA solicitation for comment on delayed repairs by existing sources when parts are not readily available and must be specially ordered. The commenter suggests that EPA provide for a delay of repair (DOR) that is caused by the lack of availability of parts in EG OOOOc.

Commenter (1391-INGAA) adds that the proposed rule solicits comment on delay of repair requirements to address the availability of replacement parts for existing compressor stations, an important matter that is of particular concern to the commenter and its members. As explained in the commenter’s Pre-Rulemaking Comments, which are included as Attachment 4 to the commenter’s letter, the parts necessary to repair a leak are not always readily available or in stock.<sup>24</sup> The commenter believes that EG OOOOc needs to contain a DOR provision for parts availability to avoid reliability impacts to customers and system disruptions. Including a DOR provision for parts availability is a practical necessity, sound policy, and is protective of the environment, according to the commenter. The commenter notes that its recommendations on DOR are modeled after regulations adopted by several states, including Colorado and Maryland.<sup>25</sup>

Commenter (1391-INGAA) requests the following for when DOR provisions of EG OOOOc should mirror DOR provisions in NSPS OOOOa:

- If parts are not available and need to be ordered, repair may be delayed until they are received.

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<sup>24</sup> See INGAA Pre-Rulemaking Comments at 4-7 & Apps. A, B.

<sup>25</sup> See 5 COLO. CODE REGS. § 1001-9:D.I.L5.; MD. CODE REGS. 26.11.41.03.A(9)(c)(i)

- Once parts have been received, operators will need to schedule the repair after receipt of the replacement part to ensure that adequate skilled labor is available, the parts have been integrity tested, and the timing of the repair will not impair reliability of the natural gas system.
- If the leak cannot be repaired without a shutdown or blowdown, then EPA should allow operators to delay making a repair until the next scheduled shutdown for maintenance that occurs after the parts have been received, not to exceed two years from discovery of the leak.

Commenter (1391-INGAA) states that EPA solicited comment and data to better understand (1) the breadth of this issue with replacement parts for existing compressor stations, (2) whether 30 days following receipt of the replacement part is appropriate for completing delayed repairs at existing compressor stations, (3) whether there should be any limit on delays in repairs under these circumstances, and (4) whether this compliance flexibility should be limited or disallowed based on the severity of the leak to be repaired.

The commenter (1391-INGAA) states that equipment utilized for gas transmission is highly specialized and is made to stringent engineering specifications. Some existing source compressors may be more than 50 years old, and compressors have changed over time. If a part breaks on an older piece of equipment, the comparable part that is used for new compressors may not be the right size or configuration for that older equipment. For example, the commenter notes that the specifications of an older compressor valve might not be standard, the system associated with an older unit might have additional connections for recirculation piping, or there might be additional changes that the operator needs to make to that system to address other regulatory requirements, such as the Pipeline and Hazardous Materials Safety Administration regulations. In such cases, the commenter states that the appropriate parts for that equipment will need to be custom ordered and/or manufactured, and it may take several months to fabricate such parts. The commenter further explains the general timeframe of replacement for several parts, details of which can be found in their comment letter.

The commenter (1391-INGAA) further explains the enormity of the challenge posed by part availability for existing compressor stations by providing examples of the types of equipment and potential leak sources that are most likely at compressor stations. The commenter explains that a typical compressor house will have multiple compressors within the building and a compressor station may have several compressor houses. The appendix to their comments provides photographs and diagrams of just some of the key equipment located in these compressor houses to illustrate the scale and breadth of the issue for the industry. The examples reviewed in Appendix B begin with integral reciprocating compressors, which are common in gas transmission.<sup>26</sup> These units include flanges, cover plates, and bolted surfaces encasing natural gas, and each of these components is a potential leak source and piece of equipment that

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<sup>26</sup> See EPA-HQ-OAR-2021-0317-1391.

may need to be replaced.<sup>27</sup> Looking at a cross-section of the integral reciprocating compressor itself, Appendix B further identifies the engine fuel system and compressors, and the flanges and cover plates associated with the compressor variable valve pockets and distance piece as additional potential leak sources.<sup>28</sup>

The commenter (1391-INGAA) goes more in-depth on valves and includes an explanation as to why keeping an inventory of parts on hand is infeasible due to the scale of the issue.

The commenter (1391-INGAA) states that, given that the number of parts that may potentially require replacement at any given facility is enormous and given that the time to obtain some of these parts can be several months, the only reasonable solution that preserves reliability of the gas supply is to include in EG OOOOc a DOR provision related to parts availability.

Response I-8-10: EPA received a similar comment on the December 2022 Supplemental Proposal. EPA's response to this comment is provided at Volume II, Chapter, 4, section 4.2.2 (Delay of Repair for Lack of Availability of Parts) .

Comment: Commenter (0787-Atmos, 1289-AEC) discusses repair timelines to avoid unnecessary emissions, as well as repairs to underground storage facilities in the full comment. The commenter supports requiring compressor station repairs in circumstances where parts are not readily available and must be special ordered to be completed 30 days following the receipt of the replacement part, provided that conducting the repair would not require a unit or wellhead shutdown.

If a shutdown is required, the commenter (1289-AEC) suggests that the repair occur during the next scheduled maintenance shutdown, especially if the emissions associated with a shutdown and startup just to repair the leak would cause more emissions than letting the leak continue until the next scheduled maintenance shutdown. The commenter agrees with other industry stakeholders that, because existing sources are older pieces of equipment, there is a higher likelihood that replacement parts will not be readily available, making lack of available parts an appropriate reason to delay a repair.

The commenter (1289-AEC) also supports keeping purchase and delivery records of the equipment that was not readily available and necessary for the repair. Likewise, if there is a delay, the commenter supports a requirement to maintain records pertaining to the delay. The company should also have records of when the repair occurred, and there should be five-year record retention requirements, thereby aligning with Clean Air Act (CAA) Title V permit renewal timelines.

Response I-8-11: EPA received a similar comment on the December 2022 Supplemental Proposal. EPA's response to this comment is provided at Volume II, Chapter, 4, section 4.2.2 (Delay of Repair for Lack of Availability of Parts). With respect to the recordkeeping

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<sup>27</sup> Id.

<sup>28</sup> Id.

requirements, EPA agrees that records pertaining to the delay and when the repair occurred should be kept for five years. The rule specifies the recordkeeping requirements at §60.5420b(c)(14)(v)(I).

Comment: Commenter (0787-Atmos) believes EPA should exclude leak repairs that require evacuation and rewatering of an underground storage cavern from the two-year maximum delayed repair requirement because, although leaks could be repaired within two years, there may be additional emissions associated with evacuating the cavern.

Response I-8-12: EPA disagrees that leak repairs that require evacuation and rewatering of an underground storage cavern should be excluded from the two-year maximum delayed repair requirement. Both EPA and the commenter conclude that leaks could be repaired within two years; given the 2-year timeframe for repair, the commenter can plan the next shutdown for maintenance purposes in a manner that minimizes additional emissions. For these reasons, EPA is finalizing the two-year maximum delay of repair for fugitive emissions.

### ***8.3.3 Opposed to Delay of Repair***

Comment: Commenter (0844-EDF *et al.*) contends that the availability of parts is not a valid concern for compressor stations.

Commenter (0844-EDF *et al.*) asserts that replacement parts can be easily procured. The commenter states that existing compressor station owners and operators are aware they will be subject to fugitive monitoring and repair requirements in the coming years. They have at least three years to begin preparing for compliance—including by ordering and stockpiling parts they know are likely to fail and cause large leaks. The commenter contends that this is more than sufficient time for these operators to plan and avoid a situation where a component fails and they are unable to obtain that component without specially ordering it. The commenter suggests that EPA focus on ensuring major leaks are quickly fixed, and not on hypothetical parts shortages occurring in 2025 and beyond.

Commenter (0844-EDF *et al.*) adds that many of the same components and pieces of equipment exist across the oil and gas supply chain. And many of those same components and pieces of equipment are known as sources of fugitive emissions and ones that commonly malfunction. The commenter notes that compressor station operators already know which parts are likely to fail and cause fugitive emissions and will therefore require repair. And if they don't know already, they have the next three years to prepare by inspecting sites, determining which components need to be upgraded or are likely to fail, and begin ordering spare parts.

Further, commenter (0844-EDF *et al.*) believes that if EPA were to allow delayed repairs based on the availability of parts, which it should not, the delay should not be permitted for major leaks. The commenter recommends that operators at a bare minimum have at least one replacement part on hand for any major leak event. According to the commenter, this type of poor planning cannot excuse delays in the repair of large emission events. Additionally, to the



extent EPA does permit some degree of compliance flexibility due to the lack of availability of certain equipment parts, the commenter states it must require the operator to support its claim through rigorous documentation, including but not limited to: a reasonable explanation of why the operator did not have a spare part on hand; a justification of why the equipment failure was not foreseeable at any point from the date of the proposed regulations until the date of failure; proof that such failures are not common at similar compressor stations of similar age; maintenance and inspection records supporting the non-foreseeability of the failure; proof and date that the replacement part was ordered immediately upon detection; and proof that the part was installed as quickly as possible upon receipt.

Response I-8-13: EPA disagrees that availability of parts is not a valid concern for compressor stations. Similar to the delay of repair provisions related to equipment leaks from equipment located at onshore natural gas processing plants, EPA is including provisions to allow the delay of repairs due to the lack of availability of parts in specific circumstances in the final rule. As described by several commenters for this action, and in previous comments on amendments to NSPS OOOOa, there are exceptional circumstances that do occur where the repair cannot be completed successfully without replacement of a part that requires custom fabrication. Please see Volume II, Chapter, 4, section 4.2.2 (Delay of Repair for Lack of Availability of Parts) for discussion of EPA's decision to allow delay of repair due to unavailability of parts. The commenter states that replacement parts can be easily procured but does not cite underlying data demonstrating this. In contrast, other commenters give examples of the lead time that can be required for parts requiring custom fabrication, which was up to 12 months depending on the size and complexity of the part. The commenter also states that compressor station operators can order and stockpile parts that may fail but does not cite underlying data demonstrating this. In contrast, other commenters contend that it is not possible to maintain an inventory of parts to avoid delaying repairs and provide supporting information about the wide variety of equipment types, models, and ages at compressor stations. EPA also disagrees that delay of repair should be disallowed for "major leaks". In order to disallow delay of leaks for "major" repairs, the term "major leaks" would have to be defined; the commenter did not offer a definition for the term "major leaks". Additionally, EPA's reasons for allowing delay of repair for parts unavailability applies equally to all leaks. EPA agrees that an operator should support its claim of delay of repair due to unavailability of parts; however, EPA partially disagrees with which data are needed to support that claim. EPA agrees that the dates the part was ordered and installed should be required. EPA disagrees that the remaining suggested documentation should be required because the remaining criteria are unrelated to the delay of repair requirements in the final rule. Please see section X.A.2 of the preamble of the final rule which details EPA's final standards related to compressor station fugitive emissions.

## **8.4 Proposed Appendix K**

Comment: Commenters (0808-American Petroleum Institute (API), 0599-Marcellus Shale Coalition (MSC), 0817-GPA) state that the proposed appendix K requirements are burdensome and not necessary for OGI monitoring at compressor stations.

Commenter (0808-API) suggests that OGI monitoring protocols for production facilities and compressor stations should be based on NSPS OOOOa requirements, not appendix K. While the commenter supports the use of OGI, appendix K as drafted is unnecessarily burdensome for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations. The commenter notes that the requirements specified in NSPS OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications. Accordingly, the commenter recommends EPA revise its November 2021 Proposal to limit the applicability of appendix K to refineries; gas plants; and, potentially, similar larger process operations in other industries.

Commenter (0808-API) includes key differences between production facilities and compressor stations versus refineries and gas plants:

- Upstream and midstream facilities are smaller, less complex, and have fewer regulated emission components. A typical well pad size is up to a few acres versus up to thousands of acres for a refinery and well sites contain tens to hundreds of components versus tens of thousands of components at a refinery.
- There are many more well sites and compressor stations. There are hundreds of thousands of well sites and compressor stations in the U.S. versus approximately 129 refineries and approximately 500 gas plants.
- Most new and existing well sites, centralized production facilities, and compressor stations are unmanned sites. Additionally, these sites are often in remote locations. Refineries and gas plants have onsite LDAR personnel.

The commenter (0808-API) lists many elements of appendix K that are impractical to implement upstream and midstream (other than gas plants).

- The dwell time and break requirements in appendix K are overly complicated, particularly for well sites, centralized production facilities, and compressor stations, where the density of fugitive emission components (number of components to view in each area) is less than for a refinery or gas plant. These dwell time and break requirements would double or triple the time required for an OGI survey and have not been demonstrated to be more effective at detecting leaks. One company estimates that 40 or more hours would be needed to conduct an OGI survey of a single site following the appendix K requirements. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with a greater environmental benefit. Furthermore, prescriptive dwell time is unnecessary and inefficient as an experienced camera operator will determine dwell time based on the circumstances that are occurring at the facility. Some components may require an extended dwell time, while other components may need less.

For these reasons noted above, the commenter (0808-API) recommends that OGI requirements for new and existing well sites, centralized production facilities, and compressor stations be based on NSPS OOOOa requirements, not appendix K.

Similarly, commenter (0599-MSD) suggests the proposed appendix K requirements for OGI surveys are overly onerous and would drastically increase the time and cost of conducting required surveys without a significant reduction in fugitive emissions. Additionally, the commenter notes that training and quality assurance requirements in the proposed appendix would result in an immediate shortage of qualified camera operators being available to conduct the required surveys. The commenter provides that they have successfully implemented OGI monitoring programs in the Marcellus region that efficiently identify and repair leaks without adding unnecessary burdens that will increase effort and cost.

According to the commenter (0599-MSD), most affected compressor stations in their region currently observe leaking components in the low single digits per survey while monitoring thousands of components present at each facility. According to the Colorado State University SU 001 Efficacy Study, there is a 60 percent increase in detection of leaks with more experienced operators and that higher rate leaks are more likely to be detected by operators with any level of experience. The commenter notes that, given the typical number of leaking components detected during a survey as noted above, increased surveys would result in very few additional leaks being detected despite the onerous additional requirements detailed in the proposed appendix K. The study also notes a 90 percent probability of detection as a threshold as opposed to 100 percent detection. See Attachment 2 of the commenter's letter for detailed comments on appendix K by section.

Commenter (0817-GPA) disagrees with significant aspects of the November 2021 Proposal's approach to equipment leaks. The commenter states that equipment leak monitoring and repair activities are already among the most resource-intensive requirements under the NSPS. Based on the November 2021 Proposal, EPA is proposing to impose a very rigid set of guidelines for OGI monitoring, outlined in proposed appendix K, without addressing the existing OGI requirements or discussing any potential need for revisions. The commenter states that they could support the use of appendix K for natural gas processing plants provided that certain revisions discussed below were implemented. Appendix K, however, according to the commenter, is unsuited for use at compressor stations. The commenter contends that, for compressor stations, appendix K would make OGI surveys extraordinarily burdensome and unnecessarily expensive. Further, even without these additional costs and burdens, the commenter believes that semiannual monitoring is the only cost-effective option.

Commenter (0817-GPA) states that appendix K would impose significant new burdens on the use of OGI at compressor stations, limiting its utility for this purpose. The commenter notes that EPA provides no explanation as to why current practices require such a significant overhaul. According to the commenter, these unwarranted burdens include the development of the operating envelope, the requirement to take breaks to avoid fatigue at such a relatively small facilities, the rigorous OGI camera operator training, and—probably most burdensome—the daily and quarterly audits. The commenter adds that these are not only a significant new burden on compressor station operators, but it eliminates much of the advantage that OGI provided over EPA Method 21. Any further proposal must definitively account for the additional costs and time

that would now be required for OGI monitoring - burdens which only create a significant disincentive against OGI monitoring.

Commenter (0817-GPA) believes it is inappropriate to apply proposed appendix K to compressor stations. Having closely reviewed appendix K, the commenter would urge EPA to reconsider its wholesale application to the midstream sector. Appendix K was developed for petroleum refineries. In a refinery setting, implementing appendix K is more feasible and cost-effective. For example, the commenter notes that refineries are more likely to be located in or near urban areas and have full-time, on-site employees or contractors to handle OGI monitoring duties. By contrast, the commenter states that compressor stations are often unmanned and located in remote areas, requiring contractors to travel to perform OGI monitoring, accompanied by operator personnel to provide access to the site.

Further, commenter (0817-GPA) suggests compressor stations have far fewer components to monitor, eliminating the economy of scale present at petroleum refineries, which often have tens of thousands of components. The commenter's data shows that gathering and boosting compressor stations would monitor an average of 1,800 components, less than half of EPA's model plant estimates. The EPA Gathering and Boosting Model Facility created for the November 2021 Proposal assumes a facility with 3,901 components.

Commenter (0817-GPA) explains that the model plant's overestimation of the number of components is important because it is the key to estimating emission reductions through OGI monitoring and the cost-effectiveness of such requirements. Unlike with a petroleum refinery, which distributes fixed monitoring overhead costs across tens of thousands of components, gathering and boosting stations will typically have less than 2,000 components.

Commenter (0817-GPA) believes that existing current OGI monitoring requirements have proven to be efficient and effective, where multiple components (*i.e.*, bolts on a tank hatch) can be scanned at a time and leaking components can be identified and tagged for repair. Under proposed appendix K, OGI camera operators would be required to view components individually from at least two different angles for a total of ten seconds.<sup>29</sup> Using the commenter's (0817-GPA) component model (1,800 components), survey time for a single facility would be five hours, with an additional 1.25 hours of breaks, one hour for calibration, and travel time. The commenter notes that, combined with increasing the frequency of monitoring and audit requirements, facility operators will expend substantially more time on OGI monitoring. Further, as explained in more detail below, the commenter contends that appendix K would add significant new costs through new audit requirements and needing to use contractors instead of in-house personnel. The commenter explains that the midstream industry uses OGI monitoring at compressor stations due to the efficiencies it can provide over EPA Method 21. The proposed appendix K, when applied to compressor stations, eliminates that utility.

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<sup>29</sup> The minimum dwell time appears to be ten seconds per component but, as described below, appendix K appears to provide conflicting dwell times.

Further, as described below, there are a number of other inconsistencies, questions, and issues with proposed appendix K that the commenter (0817-GPA) urges EPA to consider fully before moving forward to include appendix K as a required element of OGI monitoring. According to the commenter, these issues not only incorporate significant uncertainty into OGI monitoring, but unnecessarily increase time and costs while reducing the utility of using OGI. Importantly, the commenter states that the November 2021 Proposal provides no explanation as to why it proposes to dramatically revise existing OGI monitoring requirements by the incorporation of instructions at the level of detail in appendix K. The commenter recommends that EPA reassess the rationale for making the change and provide that information to stakeholders to allow for adequate opportunity to comment.

Response I-8-14: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions monitoring methods in the December 2022 Supplemental Proposal. See discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to the use of Appendix K at compressor stations.<sup>30</sup> Please also see 2021 Response to Comment Chapter 22 for additional responses to this comment regarding cost estimates and operator training.

Regarding the estimation of the number of components at gathering and boosting stations, EPA did use the component count for gathering and boosting compressor stations provided by GPA Midstream in comments located at Docket ID EPA-HQ-OAR-2021-0317 in the calculations. For further information on component counts, please see the Final TSD.

Comment: Commenter (0817-GPA) suggests that the November 2021 Proposal underestimates appendix K's cost for compressor stations. The commenter suggests that EPA re-evaluate the full costs that would be associated with requiring appendix K for compressor stations surveys, as it does not appear that the November 2021 Proposal's TSD accounted for several costs. The commenter reports that these include, but are not limited to, increased rates for contractors with camera expertise, quarterly comparative audits, side-by-side audits, training and re-training requirements, additional hours and personnel to conduct surveys, and data storage. The commenter explains that these costs will be even higher if EPA maintains the proposed operating envelope with respect to wind speed. As explained in more detail below, the commenter notes that rural locations where midstream facilities are often sited frequently experience winds far above the operating envelope requirements. This is likely to require contractors to make multiple visits before finding a day where surveys could be performed. Further, the commenter adds, unlike with petroleum refineries, because compressor stations tend to be unmanned and located in remote areas, EPA should factor in travel costs for both the contractor camera operators and facility employees who must provide access to the site.

Moreover, the commenter (0817-GPA) asserts that any cost estimate must assume an even greater increase in contractor costs for compressor stations. The commenter states that, establishing a 500-survey requirement to qualify as an OGI senior camera operator effectively

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<sup>30</sup> 87 FR 74722 (December 6, 2022).

rules out the use of in-house personnel for this role at compressor stations. According to the commenter, this means that operators will have to rely on a relatively limited number of contractors, increasing rates due to the increased demand and, for the foreseeable future, relatively small supply of qualified camera operators and senior camera operators. The commenter notes that increased contractor costs carry over to, not just the surveys themselves, but the cost of auditing requirements, side-by-side audits (involving two camera operators), and training and retraining requirements. In fact, the requirement for OGI senior camera operators to train other operators, *see* Appx. K §§ 10.2.2.110.2.2.4, and perform quarterly audits, in addition to component monitoring duties, would dramatically increase the demand for the relatively limited pool of OGI senior camera operators while simultaneously slowing the qualification of new OGI senior camera operators.

The commenter (0817-GPA) urges EPA to consider reducing these measures. For example, the commenter recommends that EPA eliminate the requirement for quarterly auditing through comparative monitoring for every camera operator. *See* Appx. K §§ 10.4-10.4.1.2. This involves two camera operators – one of them being an OGI senior camera operator —performing the same survey of at least four hours, every quarter, which will impose a significant additional cost. Similarly, the commenter recommends that EPA eliminate the requirement to record a five-minute quality assurance verification video that documents dwell times, angles, distances, and background at least once each monitoring day. According to the commenter, this requirement is unduly burdensome and continues to add to the recordkeeping nightmare that appendix K, as written, will create. At a minimum, EPA should document for stakeholders why these multiple layers of requirements are justified.

Finally, it does not appear that EPA’s cost estimates in the TSD accounted for any of the additional costs the commenter (0817-GPA) has identified above. The commenter states that EPA notes in section 12.5.4 of the November 2021 Proposal TSD that it did not update the costs associated with OGI monitoring other than adjusting for inflation and updating annual recordkeeping cost. The commenter asserts that this is inappropriate given that proposed appendix K would dramatically change how OGI monitoring would be performed in a way that would significantly increase costs. The commenter requests that EPA provide an updated cost analysis that includes the increased costs involved in following appendix K at midstream facilities, as described above. Due to the significant additional costs, the commenter also suggests that EPA re-assess the cost effectiveness of OGI monitoring under Appendix K for compressor stations prior to selecting a final frequency for leak surveys.

Response I-8-15: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions monitoring methods in the December 2022 Supplemental Proposal. *See* discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal related to the use of Appendix K at compressor stations.<sup>31</sup> Please

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<sup>31</sup> 87 FR 74722 (December 6, 2022).

also see Volume II, Chapter 22, section 22.9.2 (Burden and Cost) for additional responses to this comment regarding cost estimates and operator training.

## 8.5 Other Comments

### 8.5.1 *Fugitive Emissions Definition*

Comment: Commenter (0414-Waterspirit) urges EPA to include all methane emissions within the fugitive emissions definition of the proposed rule, including the unburned methane emitted from exhaust smokestacks from natural gas fired compressor units, generators, and boilers located at many compressor station facilities.

Commenter (0427-Private Citizen) urges EPA to include all methane emissions from all methane sources, including the unburned methane emitted out of the exhaust smokestacks from natural gas fired compressor units, generators and boilers located at many compressor station facilities along the natural gas supply chain. The commenter states that the November 2021 Proposal appears to be primarily focused on fugitive sources for methane emissions, citing the following related to fugitive emissions sources:

“As natural gas is comprised primarily of methane, every natural gas leak, or intentional release of natural gas through venting or other processes, constitutes a release of methane.” (86 FR 63114)

“Fugitive emissions component” is proposed to be any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, PRDs, open-ended lines, flanges, all covers and closed vent systems, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers or natural gas-driven pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit, are also considered fugitive emissions components.<sup>32</sup>”

The commenter (0427-Private Citizen) notes that it is not clear that any of the above two cited references specifies or includes unburned methane emissions from the exhaust of natural gas fired combustion units, such as natural gas fired turbines. They explain that all compressor stations that use natural gas fired turbines emit unburned methane in the exhaust of the turbine, according to the commenter, and the emissions of unburned natural gas in the turbine exhaust ranges from 10 to 20 tons per year per turbine. In applications to Federal Energy Regulatory Commission (FERC) in 2018 and earlier, transmission pipeline companies used to identify this

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<sup>32</sup> 86 FR 63170.

methane emissions from the turbine exhaust as methane. In recent FERC applications, transmission companies have reported this emission as unburned hydrocarbons (UHC). In the new UHC format, UHC consists of 20 percent VOC and 80 percent methane.

The commenter (0427-Private Citizen) asserts that since the methane was not burned by the turbine and escaped into the exhaust as methane, the commenter proposes that this methane emissions should also be considered as “fugitive methane emissions” and included in the component list of fugitive emissions. Either way, the commenter urges EPA to spell out this methane emissions source since some state agencies (*e.g.*, New Jersey Department of Environmental Protection), do not even recognize that methane is emitted in the smokestack of a natural gas fired turbine. In the commenter’s opinion, all agencies should be aware of this source and enforcing emissions monitoring of this source.

As an example of methane emissions in the exhaust, the commenter (0427-Private Citizen) includes two snapshots in the Appendix taken from FERC Docket CP21-95, Transco Regional Energy Access Expansion project. The second snapshot details the emissions of a Solar MARS 100 turbine. It shows the turbine as emitting 18.37 tons of UHC per year and below in the table, it specifies 80 percent of that emission as methane in 14.70 tons released in the exhaust of the solar turbine as unburned methane emission per year. This is just an estimate and greatly depends on the operational efficiency of the natural gas turbine. Over time, this unburned methane emission can increase in output.

The commenter (0427-Private Citizen) urges EPA to ensure all methane emissions from all sources at all facilities in the natural gas and oil supply chains are incorporated into the methane emissions for each facility. Especially including the methane emissions from natural gas fired units in the exhaust.

Response I-8-16: This comment on unburned methane exhausted from natural gas fired compressors, generators, and boilers (combustion slip) is outside the scope of this rulemaking. Combustion slip is addressed via other regulations, including the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (40 CFR part 63, subpart ZZZZ), New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines (40 CFR part 60, subpart IIII), and New Source Performance Standards for Stationary Spark Ignition Internal Combustion Engines (40 CFR part 60, subpart JJJJ).

### ***8.5.2 Independently Funded Monitors and FLIR Cameras***

Comment: Commenter (0414-Waterspirit) requests that EPA mandate independently funded monitors and FLIR cameras at all facilities to standardize and capture emissions.

Response I-8-17: Independently funded monitors and FLIR cameras at all facilities was not determined to be the BSER; the BSER is defined separately for each type of source.



## Chapter 9. Storage Vessels

### 9.1 General Support/Opposition

Comment: Commenter (0437-New York Office of the State Comptroller (NYOSC)) supports the proposed measures to require emissions reductions from storage tank batteries. Commenters (0781-National Tribal Air Association (NTAA), 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD), 0391-Keweenaw Bay Indian Community (KBIC), 0605-Muscogee (Creek) Nation, 0444-Damascus Citizens for Sustainability (DCS), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 1267-California Office of the Attorney General (CA AG) *et al.*) also generally support the proposed measures to require emission reductions from storage tank batteries. Commenters (0781-NTAA, 0605-Muscogee (Creek) Nation) support the strengthening of compliance requirements and monitoring for tank hatches or openings. Commenter (0444-DCS) states that the new rule will also go a long way to meeting U.S. obligations under the Global Methane Pledge, which requires a reduction of methane emissions by 30 percent by 2030. Commenters (0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ), 0844-Environmental Defense Fund (EDF) *et al.*, 0789-Pennsylvania Department of Environmental Protection (PA DEP), 0425-Darrah Oil Company, LLC (Darrah)) support EPA's November 2021 Proposal to move away from calculating the potential to emit (PTE) for each storage vessel individually towards calculating the PTE based on each tank battery. One commenter (0727-ODEQ/OSEE) states that doing so would improve the ability of industry to determine if a well site/compressor station is an affected facility and would also improve the ability of regulatory agencies to determine compliance with federally enforceable limits, lessening confusion for all parties and allowing for a more straightforward determination of applicable requirements. The commenter (0727-ODEQ/OSEE) states that this would align with their practice to limit emissions from new and existing storage vessels and tank batteries, including their use of a successfully piloted low-emission storage tank design that further maximizes gas recovery, eliminates the need to flare tank vapors during normal operation and minimizes emissions through a reduction in the number of potential leak sources, as well as components that can lead to common equipment failures, including open thief hatches.<sup>1</sup>

Commenter (0808-American Petroleum Institute (API)) supports the proposed 6 tons per year (tpy) VOC threshold for a single storage vessel or tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. The commenter also generally supports EPA's November 2021 Proposal for 95 percent emission reduction for existing storage vessels and tank batteries with potential methane emissions of 20 tpy or more under EG OOOOc.

Commenter (0817-GPA Midstream Association (GPA)) generally supports the proposed 6 tpy VOC threshold for storage vessels, and the retention of a 95 percent control efficiency standard.

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<sup>1</sup> [https://www.devonenergy.com/documents/Sustainability/DVN\\_2021\\_SustainabilityReport.pdf](https://www.devonenergy.com/documents/Sustainability/DVN_2021_SustainabilityReport.pdf).

The commenter does not oppose a threshold of 20 tpy for methane emissions from existing storage vessels but cannot support a lower threshold.

Commenter (0831-American Exploration and Production Council (AXPC)) generally supports EPA's approach to regulate storage vessels as a single storage vessel or tank battery and does not take issue on the 6 tpy VOC threshold for completely new sites and a 20 tpy threshold for existing sites.

Several commenters (0844-EDF *et al.*, 0425-Darrah, 0831-AXPC, 1267-CA AG *et al.*) support the proposed amended definition of "storage vessel" to include tank batteries. Commenter (0844-EDF *et al.*) notes it is a marked improvement over the current regulations, which define storage vessel affected facilities based only on an individual vessel's PTE and allows for tanks within the same battery to be treated separately, either as an affected facility (and thus subject to NSPS OOOO) or not (and thus subject to no standard).

Commenter (0425-Darrah) supports the tank battery approach instead of determining applicability for individual tanks, noting that the tanks work together, not separately, and thus should be considered as emission sources in that way. The commenter further states that separating storage vessel affected facilities into [single] vessels will only create confusion and unnecessary burdensome work in compliance and monitoring.

Response I-9-1: EPA acknowledges the commenters support. Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (0777-Ascent Resources, LLC (Ascent)) recommends that EPA retain the current practice of basing applicability on the individual storage vessel. The commenter adds that if EPA seeks to extend the 95 percent control requirement to additional tanks that are not currently considered affected facilities under NSPS OOOO or NSPS OOOOa, they recommend that EPA propose a different emissions threshold for individual storage vessels and justify that the 95 percent control requirement for those individual storage vessels will be cost-effective. The commenter rationalizes that determining the applicability of the rule on an individual vessel-by-vessel basis will help avoid unreasonable capture and control requirements for small vessels that are part of a larger tank battery and will assist owners and operators in assessing the potential need to install NSPS OOOOb or EG OOOOc compliant emissions controls, when evaluating the purchase and construction of a storage vessel.

Response I-9-2: EPA disagrees with the commenter that there needs to be a different applicability threshold for a tank battery. While both NSPS OOOO and NSPS OOOOa define individual storage vessels as affected facilities if they exceed the applicability threshold of 6 tpy VOC (potential for emissions), EPA has provided clear rationale and basis for treating all storage vessels in a tank battery, as defined in the rule, as a single unit for purposes of determining applicability. The final rule defines a tank battery as a "group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present." While not clear in the comment, EPA believes that this definition would alleviate any concern of small tanks being subject to control when part of a

large battery if those small tanks are not manifolded together for liquid transfer. For the EPA analysis of cost effectiveness for storage vessels, the Docket Item No. EPA-HQ-OAR-2021-0317-0039. In this analysis EPA addresses the applicability threshold for tanks and tank batteries with respect to the cost of controls on single tanks with emissions of 6 tpy VOC and 20 tpy methane.

## 9.2 Applicability

### 9.2.1 Definition of Storage Vessel

Comment: Commenter (0817-GPA) requests that the definition of “storage vessel” in NSPS OOOOb match the definition found in the existing NSPS OOOOa rule as the November 2021 Proposal does not discuss any definition of “storage vessel.”<sup>2</sup> The commenter states that EPA’s prior record on the definition of storage vessel began with an overly broad view of what constitutes a storage vessel, such as including flow through vessels, process vessels, and tanks storing materials with little or no potential for VOC emissions, such as used oil, glycol, or molecular sieve,<sup>3</sup> but subsequently corrected the “storage vessel” definition in NSPS OOOOa to be consistent with that provided in 40 CFR 63.671: “a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water....” See 81 FR 35824 and 35936 (June 3, 2016) (codified at 40 CFR 60.5430a). The commenter explains that confirming that EPA will use the NSPS OOOOa definition will provide continuity and certainty to regulated entities.

Response I-9-3: The final rule for NSPS OOOOb defines storage vessel as follows:

*Storage vessel* means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

- (1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site

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<sup>2</sup> The Proposed Rule states that it is carrying over some definitions from NSPS OOOOa to proposed NSPS OOOOb, such as “well site,” 86 Fed. Reg. at 63,165, but does not mention other definitions. Absent some statement that all definitions from NSPS OOOOa will be used in NSPS OOOOb, selectively carrying over some definitions but not others creates uncertainty for owners and operators.

<sup>3</sup> For instance, in its 2012 NSPS OOOO rulemaking, EPA defined a storage vessel as one that is “designed to contain an accumulation of liquids and other materials.” 77 Fed. Reg. 49,490, 49,566 (Aug. 16, 2012).

for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- (2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.
- (3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

This same definition is also included in the final EG OOOOc, with reference to specific sections in the model rule language for EG OOOOc replacing the NSPS OOOOb references. Other than these references the definition is identical to the definition in NSPS OOOOa.

### **9.2.2 Definition of Tank Battery**

Comment: Commenters (0810-The Petroleum Alliance of Oklahoma (Petroleum Alliance-OK), 0814-Independent Petroleum Association of America (IPAA) *et al.*, 0817-GPA) are concerned with the use of the term “adjacent” in the definition of tank battery. Commenters (0810-Petroleum Alliance-OK, 0817-GPA) recommend not including this term as it is vague and unclear, and commenter (0814-IPAA *et al.*) believes that both EPA and Title V sources understand the challenges and problems with defining and understanding what “adjacent” means. By way of example, commenter (0810-Petroleum Alliance-OK), explains that tanks on a site may receive fluids from the same source but are separated by significant distances for various reasons such as safety. The commenter suggests that these types of tanks should undergo a separate emission calculation as compared to the tanks manifolded together elsewhere on the location.

Commenter (0817-GPA) states that any proposal to aggregate “physically adjacent” storage vessels, or groups of storage vessels, is problematic because, among other reasons, adjacency is not defined. The commenter is concerned that this deprives owners and operators of fair notice as to what is required, let alone the certainty that is essential for operations and planning. The commenter provides by way of example, that it is not clear how close the tanks would have to be to be deemed adjacent—such as whether two tanks on opposite sides of a facility would be considered “physically adjacent.” Using this type of vague term, the commenter explains, would leave it open for interpretation, which leads to uncertainty and inconsistent application of the regulation. The commenter reminds EPA that when a similar concept of “adjacency” was left to interpretation in other contexts under air regulations, different EPA inspectors and different states interpreted “adjacent” differently, resulting in disputes, permit challenges, extensive EPA investment of time in explanatory guidance that did not provide real clarity, and costly litigation—that ultimately found against EPA. *See Summit Petroleum Corp. v. U.S. EPA*, 690 F.3d 733 (6th Cir. 2012) (rejecting EPA’s interpretation of “adjacent” with respect to aggregating oil and gas wells into a single source). The commenter urges EPA to avoid this thicket and remove the term “physically adjacent.” The commenter further states that regardless, even where equipment are truly immediately adjacent to one another under a realistic, physical sense, EPA has proffered no justification for considering them to be a single emission source, simply due to physical proximity and having throughput from the “same source,” and has offered no data or other evidence to suggest this definition would provide any meaningful benefit in the form of material emissions reductions warranting additional regulation. The commenter explains

that storage vessels may be arranged this way merely due to the size of and space available at a particular location, yet they are entirely independent emission sources, meaning that one can be removed from service without affecting the other. The commenter states that if storage vessels operate independently, then they should be treated as separate equipment and separate affected facilities. Further, the commenter states that EPA should limit the definition to encompass vessels that are manifolded together for liquid transfer—not for vapor transfer. The commenter believes that it is inappropriate to assume that because multiple storage vessels share a vapor header, they should be considered the same source; explaining that multiple sources routinely share a common closed vent system for routing emissions to a control device, including other non-tank sources. By way of example, the commenter provides that if a storage vessel shares the same closed vent system as a pneumatic pump, this does not justify considering the storage vessel and pneumatic pump as the same source and is equally true for storage vessels that share a common vapor header but operate independently. The commenter also is concerned that if sharing a common vapor header would make storage vessels subject to new source regulation, operators could respond by using multiple (and therefore inefficient) vapor collection systems. Finally, the commenter states that limiting the scope to vessels manifolded together for transferring liquids is consistent with the approach taken by states<sup>4</sup> that have considered the issue.

Commenters (0831-AXPC, 1267-CA AG *et al.*) generally support EPA's approach to regulate storage vessels as a single storage vessel or a tank battery affected facility. However, the commenter (0831-AXPC) does have concerns with the definition of tank battery as they believe it is overly complex and would create confusion potentially leading to unintended consequences. Commenters (0831-AXPC, 0814-IPAA *et al.*, 0810-Petroleum Alliance-OK, 0817-GPA) suggest a clearer delineation, would be a definition of tank battery based on tanks that are manifolded by liquid line (and not by vapor line) as per the modified definition offered below, which commenter (0831-AXPC) states would avoid confusion around applicability and align with existing state programs.

Commenter (0808-API) also suggests the proposed definition of tank battery should be based on manifolded tanks by liquid line. EPA's November 2021 proposed definition of a tank battery is overly complex given the objective of including a tank battery as a storage vessel affected facility. Based on the definition of a "storage tank" in Colorado Regulation 7, "manifolded by liquid line" is a simple and clear criterion for defining a group of storage vessels as a tank battery. The Colorado Air Quality Control Commission established a definition for a "storage tank" for Regulation 7 by expanding upon the definition of a storage vessel in NSPS OOOO and OOOOa to include storage vessels manifolded together by liquid line. The other criteria (e.g.,

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<sup>4</sup> For example, Colorado Regulation 7 recognizes that storage tank batteries manifolded via liquids lines are appropriately combined as one source because the smaller vessels could be effectively replaced with one larger vessel. The same is not necessarily true about vessels sharing a common vapor header or merely physically adjacent and receiving liquids from the same source. In 2014 revisions to Regulation 7's definition of "storage tank," the Colorado Department of Public Health and Environment Air Quality Control Commission explained that to "further clarify the concept of manifolded within the definition of 'storage tank,' the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery." See Code of Colorado Regulations, 5 CCR 1001-9-F, Statements of Basis, Specific Statutory Authority and Purpose (Dec. 21, 1995).

physically adjacent, manifolded for vapor transfer) in EPA's November 2021 proposed definition would cause potential confusion around applicability. The commenter offers a suggested definition of a tank battery edit based on EPA's November 2021 proposal language as follows:

The EPA proposes to define a tank battery as a group of storage vessels that are physically adjacent and that receive fluids from the same source (e.g., well, process unit, compressor station, or set of wells, process units, or compressor stations) or which are manifolded together for liquid or vapor transfer.

Commenter (1421-DePuy Oil and Gas Co. (DePuy)) states that NSPS OOOOa, NSPS OOOOb, and EG OOOOc are duplicative as they relate to storage tanks and other equipment used in emissions calculations for baseline methane emissions. The commenter states that there is overlap of single tanks at a well site versus storage tanks at a central facility and requests that EPA provide clarity on how to address this. The commenter is concerned that any overlap of tank emissions calculations or calculations related to other well site equipment artificially increases the calculation of baseline emissions.

Response I-9-4: See discussion in section IV.J.1.b of the December 2022 Supplemental Proposal.<sup>5</sup>

With respect to the determination of baseline methane emissions, in the November 2021 Proposal, EPA requested comment on whether facilities should use uncontrolled PTE calculations for their storage vessels in their site-level baseline estimates for determining the frequency of monitoring of fugitive emissions components at well sites. This determination is separate and distinct from the determination under 60.5365b(e)(2). EPA is not finalizing a site-level baseline emissions threshold for fugitives monitoring. See section IV.A.1.a.ii of the December 2022 Supplemental Proposal for discussion and responses to comments regarding site-level baseline emissions.<sup>6</sup>

### ***9.2.3 Definition of Centralized Production Facility***

Comment: Commenters (0847-Mull Drilling Company, Inc. (Mull), 0881-O'Neal Oil & Gas Company (O'Neal), 0598-Countrymark Energy Resources, LLC (CER), 1085-Small Operator Society LLC (SOS), 1331-C. I. McKown & Son, Inc. (McKown), 0938-TXOGA Texas Oil & Gas Association (TXOGA)) state that the final rule needs to clarify the difference between a storage vessel/tank battery and a centralized production facility. Commenter (0847-Mull) questions how EPA plans to treat them for inspection purposes as it has huge implications for the inspection process, time, and cost.

Commenter (0598-CER) states some of their facilities partially meet the definition of a centralized tank battery, but not the complete definition and based on experience with NSPS

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<sup>5</sup> 87 FR 74800 (December 6, 2022).

<sup>6</sup> 87 FR 74724-74725 (December 6, 2022).

OOOOa, meeting some of the definition does not necessarily mean the facility is exempt from the definition.

Response I-9-5: The final rules define tank batteries and centralized production facilities at §60.5530b as follows:

*Tank battery* means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

*Centralized production facility* means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

A tank battery may be located at or on a centralized production facility, but the affected facility status of any fugitive emissions components located at the centralized production facility does not impact the affected facility status of the storage vessels or tank batteries that are located at the centralized production facility. To determine if a tank battery is an affected facility for purposes of the control requirements in §60.5395b, owners/operators must calculate the potential for VOC and potential for methane emissions as specified in §60.5365b(e). If the potential for emissions exceeds the applicability thresholds (6 tpy VOC or 20 tpy methane), then the tank battery is a storage vessel affected facility.

#### **9.2.4 NSPS K, Ka, and Kb**

Comment: Commenter (0938-TXOGA) suggests that EPA include a clarification that storage vessels at well sites and centralized production facilities are subject to NSPS OOOOb (if new, constructed, or modified) and EG OOOOc (if existing) instead of NSPS K, Ka, or Kb.

Commenter (0808-API) also supports the proposed alternative approach to specify, within NSPS OOOOb and EG OOOOc, that storage vessels at well sites and centralized production facilities are subject to requirements in those regulations instead of NSPS K, Ka, or Kb, as the commenter believes that this approach provides a clearer path for determining regulatory applicability for storage vessels in the production segment. The commenter notes that some storage vessels at production facilities store liquids that do not contain dissolved gases and for those tanks, facilities could still opt to control emissions using a floating roof, as is currently allowed under NSPS OOOOa (See 40 CFR 60.5395a(b)).

Response I-9-6: In the 2021 proposal, in response to questions regarding whether NSPS Kb would apply to storage vessels at oil and gas centralized production facilities, the EPA discussed

the history of an exemption in NSPS Kb and solicited comment on “whether it would be more appropriate to specify within the proposed NSPS OOOOb and EG OOOOc that storage vessels at well sites and centralized production facilities are subject to the requirements in NSPS OOOOb and EG OOOOc instead of NSPS K, Ka, or Kb.” 86 FR 63184. However, EPA did not propose, and therefore has not included in the final rule, any clarifying statements on this matter. The EPA continues to believe that the applicability of, and any exemption from, standards in a rule is best specified in that rule or its rulemaking record in order to provide clarity and adequate notice. The EPA notes that October 4, 2023, the EPA published a proposed subpart Kc based on its review of NSPS Kb pursuant to CAA section 111(b).<sup>7</sup> To the extent further clarification is needed regarding the applicability of NSPS K, Ka, or Kb, an owner or operator may also request that EPA make an applicability determination for any specific storage vessels. Finally, as the commenter points out the final rule allows the use of a floating roof for compliance with the standards for storage vessel affected facilities at 40 CFR 60.5395b(b)(2) where the storage vessel affected facility is not located at well sites or centralized production facilities and where flash emissions are not a concern. In contrast a floating roof tank cannot be used at production and centralized production facilities because flashing emissions are of concern for storage vessels at production and centralized production facilities. The final OOOOb and OOOOc (and OOOO and OOOOa before them) standards require the use of a closed vent system, control device, and fixed roof for storage vessel affected facilities at well sites or centralized production facilities and preclude the use of a floating roof tank to meet compliance requirements.

### ***9.2.5 Emissions Threshold for Tank Battery Applicability***

Comment: Several commenters (0789-PA DEP, 0781-NTAA, 0943-Sault EPD, 0844-EDF *et al.*, 0832-New Mexico Environment Department (NMED), 0715-Dayenu Circle of Jewish Silicon Valley (DCJSV), 0391-KBIC, 0605-Muscogee (Creek) Nation, 0444-DCS, 0833-Ute EPD, 1267-CA AG *et al.*) recommend that EPA use a lower emissions threshold for determining applicability for tank batteries.

Commenter (0789-PA DEP) recommends a single 2.7 tpy threshold for VOC emissions based on potential emissions, which has been used by the commenter for applicability since 2013 and it has proven to be successful, as opposed to the proposed bifurcated thresholds for VOC emissions (potential to emit limit of 6.0 tpy or actual emissions of 4.0 tpy).

Commenters (0781-NTAA, 0943-Sault EPD, 0391-KBIC, 0605-Muscogee (Creek) Nation, 0833-Ute EPD) suggest that EPA apply the requirements to storage tanks with potential to emit of 4 tpy or more of VOC rather than 6 tpy for new sources and a lower threshold such as 12 tpy of methane rather than 20 tpy for existing sources.

Commenter (0844-EDF *et al.*) states that based on what the states with heavy oil and gas development have required, or proposed, in their storage vessel requirements, EPA’s November 2021 proposed applicability thresholds are too high and must be lowered. The commenter believes that EPA’s high thresholds are based on unrealistically high estimates for the costs of emission controls for tanks, compared to the emission control costs estimates used by the states. The commenter surmises that EPA’s reasoning for the proposed high control thresholds of 6 tpy

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<sup>7</sup> See 88 FR 68535 (October 4, 2023).



for VOC for new and modified tanks and 20 tpy for methane for existing tanks arises from EPA's very high estimate of the costs of tank controls. The commenter provides, by way of example, that EPA estimates (*i.e.*, the annualized cost of a combustor to control tank emissions is \$31,552 at a new site and \$34,166 at an existing site<sup>8</sup>) for even the lowest-emitting sites are more than a factor of four higher than the cost estimates used by Colorado in support of its rulemaking for existing tanks. The commenter recommends that EPA re-examine its methodology for estimating the costs of controls for tanks and consider lower thresholds for control of new and existing tanks.

By further way of example, the commenter (0844-EDF *et al.*) references the State of Colorado (CO), Wyoming (WY), Pennsylvania (PA), California (CA) and New Mexico (NM). The commenter states that notably, when CO lowered its applicability threshold to 2 tpy in 2019, CO performed a cost-effectiveness analysis for three different applicability thresholds (2-3 tpy; 3-4 tpy; and 4-6 tpy), looking at four different classes of storage vessels.<sup>9</sup> In Figure 19 ("Average Control Cost (\$/ton VOC)") of their letter, the commenter summarizes the results of the analysis performed by CO, and states that CO found that control of all tanks with actual uncontrolled emissions over 2 tpy was cost-effective in every single class of storage vessel the state looked at<sup>10</sup> and that even looking at the lowest threshold of 2-3 tpy, every class of tank was cost-effective to control. The commenter (0844-EDF *et al.*) also references requirements in WY where any new<sup>11</sup> or existing<sup>12</sup> storage vessels with potential flash emissions exceeding 4 tpy in the Upper Green River Basin Nonattainment Area are required to be controlled by destroying VOC by 98 percent; and since at least 2013, requires the control of all flash emissions from any new<sup>13</sup> storage vessels located at a new site statewide with more than one well producing any significant amount of associated gas, without any applicability threshold.<sup>14</sup>

In PA, the commenter (0844-EDF *et al.*) reports that since 2013 all new storage tanks emitting more than 2.7 tpy of VOC at production sites are required to be controlled<sup>15</sup> and the VOC applicability threshold was extended to new storage vessels at natural gas compressor stations and processing plants in 2018.<sup>16</sup> The commenter also cites the State of California, which requires

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<sup>8</sup> See spreadsheet "StTanks Control Costs v5.1" (document EPA-HQ-OAR-2021-0317-0039, attachment 20), sheet "New", cell M9, and sheet "Existing," cell M9.

<sup>9</sup> Those are: Condensate tanks in the Denver Metro North Front Range (DMNFR) Nonattainment Area; oil and produced water tanks in DMNFR Nonattainment Area; condensate tanks outside of the DMNFR Nonattainment Area; and oil and produced water tanks outside of the DMNFR Nonattainment Area.

<sup>10</sup> See Colo. Dep't Pub. Health & Env't, Economic Impact Analysis (Final Analysis), Regulation No. 7 (Dec. 17-19, 2019), available at [https://drive.google.com/file/d/1ZqvuyhJn1kb237d22vD0MDcxk\\_ovasP/view](https://drive.google.com/file/d/1ZqvuyhJn1kb237d22vD0MDcxk_ovasP/view).

<sup>11</sup> Wyoming DEQ (December 2018), Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, page 14. Available at: <https://eqc.wyo.gov/Public/ViewPublicDocument.aspx?DocumentId=17100>.

<sup>12</sup> See 020-8-0002 Wyo. Code R. § 8-6(c)(i)(A) (Upper Green River Basin permit by rule for existing source).

<sup>13</sup> This requirement was extended to any modified site in the state in 2018. See December 2018 Guidance, *supra* note 734 at 7.

<sup>14</sup> See Wyoming DEQ (September 2013), Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance, page 6; See also December 2018 Guidance, *supra* note 734 at 7 (note definitions of "PAD" facilities on page 75 of 2013 guidance and page 51 of 2018 guidance).

<sup>15</sup> Pennsylvania Dept. of Environ. Protection (2018), General Plan Approval And/Or General Operating Permit GP5A, Section E(1)(b), (c).

<sup>16</sup> Pennsylvania Dept. of Environ. Protection (2018), General Plan Approval And/Or General Operating Permit GP5, Section E(1)(b).

control of new and existing tanks emitting more than 10 metric tpy of methane,<sup>17</sup> which the commenter states is comparable to EPA's November 2021 proposed applicability threshold of 20 short tpy of methane for existing tanks. Finally, the commenter references NM's proposed regulations that would require the control of new tanks with potential emissions greater than 2 tpy and existing tanks with potential emissions of 3 tpy VOC for tanks in multi-tank batteries, and 4 tpy for existing tanks in single tank batteries.<sup>18</sup>

Commenter (0832-NMED) recommends that EPA consider a lower applicability threshold for new and existing storage vessel control requirements. The commenter explains that the applicability threshold should be set lower, considering that VOC emissions from new and existing storage vessels and tank batteries are a significant source of emissions from the oil and gas sector. The commenter suggests that EPA consider the NMED proposed Part 50 applicability thresholds for new and existing storage vessels, which require controls for new storage vessels with a potential to emit (PTE)  $\geq 2$  tpy of VOC, existing storage vessels in multi-tank batteries with a PTE  $\geq 3$  tpy of VOC, and existing storage vessels in single tank batteries with a PTE  $\geq 4$  tpy of VOC.

Commenters (0715-DCJSV, 1267-CA AG *et al.*) recommend that EPA address smaller storage tanks and require lower leak rates, such as required by CO and NM.

Commenter (0739-Citation Oil & Gas Corp. (Citation)) states that the addition of a 20 tpy or greater methane emissions threshold for existing tank batteries would require such tank batteries to reduce emissions by 95 percent, would result in a significant increase in demand for new storage vessels, capture, and control equipment, as well as associated closed tank venting and control systems.

Commenter (0820-Pioneer Natural Resources USA, Inc. (Pioneer)) requests that EPA provide their intent and reasoning for selecting the 6 tpy VOC limit for new tank batteries and the 20 tpy methane limit for existing sources, as it differs from the approach taken in NSPS OOOOa.

Commenter (0599-Marcellus Shale Coalition (MSC)) states that doing so will allow for full stakeholder transparency and involvement in the rulemaking process. Commenter (0577-Kansas Independent Oil & Gas Association (KIOGA)) inquires whether the proposed GHG standards for 95 percent methane reduction for storage tanks with PTE > 20 tpy shown in table 3 at 86 Fed. Reg. 63121 is more stringent than the current 6 tpy VOC threshold for tank emission reductions.

Commenter (0793-PBPA Permian Basin Petroleum Association (PBPA)) stated that EPA's November 2021 Proposal would significantly expand the number of storage tanks, both new and existing, that will be forced to install vapor recovery units (VRUs) at a tremendous cost and unjustified by the minor reductions in methane and VOC emissions. The commenter explains that both the NSPS and EG are expected to directly impact hundreds of thousands of storage

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<sup>17</sup> Cal. Code Reg. tit. 17 § 95668(a)(6), (7).

<sup>18</sup> New Mexico Environment Department, Proposed 20.2.50 NMAC (Jan. 20, 2022 version), at 20.2.50.123(A). Available at: <https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-ProposedPart-20.2.50-January-20-2022-Version.pdf>.

facilities, requiring additional emissions controls, many of which will have their own emissions and will provide only limited emission reductions at smaller operations.

Response I-9-7: EPA discussed the results of the analysis which was used to establish emissions limits for storage vessels in section XII.B.1.e of the November 2021 Proposal. See 86 FR 63199.

EPA cannot support a threshold of 2.7 tpy or 4 tpy VOC because our determination of cost-effectiveness is over \$8,000 per ton of VOC for either level.<sup>19</sup>

In another response to the question of selecting a lower threshold, a commenter suggested that EPA cost calculations were higher than for the state of Colorado, and that EPA should adopt a lower threshold based on the Colorado cost analysis. The EPA reviewed the costs estimates used to support the CO rule and we disagree with the comment because we found significant differences in assumptions used in the analysis and concluded that the Colorado cost estimate did not fully assess all costs that would be incurred by the facility, particularly with respect to the requirements in the final rule. We found our cost for the flare itself is very close to the cost of the flare in the CO evaluation. However, our costs included additional equipment such as a flame arrestor, flare header piping, and a continuous monitoring system for the pilot flame, the latter is required as part of the final rule. Our costs also included sales tax and much higher installation costs, including foundation, contractor fees, contingency costs, and testing costs (initial visible emissions monitoring). Our operating costs are also higher than those projected by Colorado, including operating labor, which includes labor needed to perform required inspections and visible emission monitoring, maintenance labor, and maintenance materials rather than just maintenance costs as estimated by Colorado. We also projected higher natural gas use costs, likely because we require a pilot flame present at all times. Our costs also included indirect operating costs for overhead on labor and materials costs, property tax and insurance, none of which were included in the Colorado cost estimate. Finally, we used higher rate of return (7% rather than 5%) to amortize the capital costs. Together, our cost estimates led to significantly higher annualized costs for the storage tank control. Based on our review of the two cost estimates, we found that the Colorado analysis may not be complete and representative on a national basis of the costs operators will incur to meet the control requirements as provided in the final rule. The commenter did not explain why Colorado's assumptions are better than EPA's assumptions in this analysis. For these reasons, the EPA disagrees with the comment and will finalize the threshold as proposed.

#### ***9.2.6 Legally and Practicably Enforceable Limits***

Comment: Several commenters (0755-Texas Pipeline Association (TPA), 1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*, 0599-MSD, 0820-Pioneer, 0808-API, 0817-GPA, 0844-EDF *et al.*, 0938-TXOGA, 0456-Air Management Program, Wisconsin Department of Natural Resources (WDNR), 0776-Air Pollution Control Division, Colorado Department of Public Health and Environment (CDPHE), 0944-Kuva, 1267-CA AG *et al.*) express concerns

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<sup>19</sup> See spreadsheet "StTanks Control Costs v6.0" (document EPA-HQ-OAR-2021-0317-@@@@, attachment ??), sheet "New", cells U9 through U11, and U40.

regarding elements of the November 2021 Proposal that EPA proposes for “legally and practicably enforceable” limits.

Commenter (0755-TPA) states that the November 2021 proposed revisions to the concept of legally and practically enforceable emissions limits, within the context the storage vessel applicability thresholds, are unduly prescriptive and unnecessary. The commenter states that EPA now proposes a complex and cumbersome regulatory scheme whereby the owner or operator of a storage vessel, to claim a limit that keeps the vessel under threshold limits, would have to show that all the following elements are in place:

- i. A quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment;
- ii. An averaging time period for the production limit in (i) (if a production-based limit is used) that is equal to or less than 30 days;
- iii. Established parametric limits for the production and/or operational limit(s) in (i), and where a control device is used to achieve an operational limit, an initial compliance demonstration (i.e., performance test) for the control device that establishes the parametric limits;
- iv. Ongoing monitoring of the parametric limits in (iii) that demonstrates continuous compliance with the production and/or operational limit(s) in (i);
- v. Recordkeeping by the owner or operator that demonstrates continuous compliance with the limit(s) in (i-iv); and
- vi. Periodic reporting that demonstrates continuous compliance.

The commenter (0755-TPA) states that EPA is proposing to cast aside the traditional means of assessing PTE limits for threshold applicability purposes, and to put in its place a highly prescriptive scheme that would constitute regulatory overkill and add uncertainty to whether and how limits could be claimed going forward. The commenter notes that where a rule contains an emissions threshold under which a given piece of equipment is not subject to the rule's requirements, it is fair and logical that the equipment be considered outside of rule coverage, where emission controls or limitations are in place to keep emissions below the threshold, even though in an uncontrolled state the equipment is capable of producing emissions above threshold levels. The commenter adds that this concept has been embodied in EPA rules for decades<sup>20</sup> and was incorporated into NSPS OOOOa in 2016.<sup>21</sup> The commenter states that they are not aware that it has caused any significant problems or compliance issues in the context of NSPS OOOOa or more generally.

Commenter (0944-KUVA) proposes for EPA to consider conducting an analysis as to whether relocatable or continuous installed OGI cameras could be utilized in connection with the definition for legally and practicably enforceable.

Commenters (1341-PGCC et al.) state that EPAs clarifying definition of a legally and practicably enforceable limit is in contravention of long- established air permit exemptions for de minimis individual sources, such as those in existence in PA, NY, and elsewhere. See 25 PA. Code

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<sup>20</sup> See, e.g., 40 CFR § 51.165(a)(1)(iii); 40 CFR § 51.166(6)(4); 40 CFR § 52.21(b)(4).

<sup>21</sup> 81 FR 31500 (June 3, 2016).

127.14 and 6 CCR-NY 201-3.2 (both allowing pa department of environmental protection (dep) and the NY state (NYS) department of environmental conservation (DEC) to exempt from air permitting certain sources). The commenter suggests that the November 2021 proposed "clarifying" definition of "legally and practicably enforceable limit" would appear to require that all storage tanks within a tank battery be covered under an air permit that imposes production limits, monitoring, recordkeeping, and potentially other explicit requirements to maintain an exemption from the proposed expanded requirements. See 86 FR 63201-63,202. The commenters believe that EPA's November 2021 proposal could lead to significant numbers of storage tanks being covered (and potentially retroactively covered) under NSPS OOOOa, proposed NSPS OOOOb, and proposed e.g. OOOOc and questions EPA's legal authority to upset state air permitting programs and exemptions in this manner.

Response i-9-8: The proposed criteria, which EPA is finalizing, are for evaluating whether a facility is subject to legally and practicably enforceable emission limits for new and modified facilities under new and modified sources under OOOOb and existing sources under OOOOc e.g. See 86 FR 63201 (the EPA is clarifying the term "legally and practicably enforceable limits" as it related to storage vessel affected facilities in the proposed NSPS OOOOb and EG OOOOc). These criteria will apply going forward, and will not be used to assess whether owners and operators correctly determined that their storage vessels are not subject to OOOO or OOOOa. As the EPA stated in our proposal and supplemental proposal, the enforcement record shows<sup>22</sup> that the EPA must further specify what legally and practicably enforceable emissions limitation means in the oil and gas sector because we have found through enforcement actions that sources have relied on inadequate limitations to support their status as exempt from the storage vessel provisions of the NSPS. However, the EPA disagrees with the comment that our action results in the need for all storage tank owners and operators to obtain site-specific permits. A permit-by-rule or general permit system that creates legally and practicably enforceable limits that meet the criteria would not require a site-specific permit. Further, no owner or operator is required under this provision to obtain any minor source permit. The owner or operator could instead comply with storage vessel requirements under OOOOb.

As mentioned above, the provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source designated facilities under OOOOc, and are not retroactively applicable to OOOO or OOOOa sources. The EPA enforcement cases to date have relied on EPA guidance and the provisions of OOOO and OOOOa, and will continue to do so to determine whether legally and practicably enforceable limits are met in permits or other requirement established under federal, state, local or tribal authority.

Comment: Commenter (0599-MS) states that the terms "legally and practically enforceable" are currently defined and codified by EPA in synthetic minor determinations under the title V operating permit program and in the prevention of significant deterioration and nonattainment

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<sup>22</sup> See the preamble to final rule, section XI.J.1 for further discussion.

new source review programs. The commenter stated that the proposed NSPS OOOOb and EG OOOOc definitions should remain consistent with existing regulations.

Response I-9-9: The criteria for a "legally and practically enforceable" limit (LPE criteria) that we are finalizing in this action are for a specific use. They are specifically designed to assure that credible limitations on storage vessels in the oil and gas sector and their controls are in place when determining whether these storage vessels are affected facilities under OOOOb or designated facilities under EG OOOOc. As such, the EPA disagrees that these criteria must be identical to the title v program terms, which are by their programmatic nature more general than would be found in a category-specific rule. The EPA does not agree that legally and practicably enforceable criteria under the title V, PSD, or NNSR programs are inconsistent with the specifications in NSPS OOOOb and OOOOc. Further, the commenters are incorrect that EPA's title V (40 CFR part 70 and 71), PSD, or NNSR regulations currently define legally and practicably enforceable. The only place EPA has defined legally and practicably enforceable in the NSR program is in part 49 for tribal minor NSR. That definition in 40 CFR 49.167 defines enforceable as a practical matter and not legally and practically enforceable. This difference notwithstanding, the description of practical enforceability as a practical matter requires nothing different. It requires the following<sup>23</sup>:

Practical enforceability for an emission limitation or for other standards (design standards, equipment standards, work practices, operational standards, pollution prevention techniques) in a permit for a source is achieved if the permanence provisions specify:

- i. A limitation or standard and the emission units or activities at the source subject to the limitation or standard;
  - ii. The time period for the limitation or standard (e.g., hourly, daily, monthly, and/or annual limits such as rolling annual limit) and
  - iii. The method to determine compliance, including appropriate monitoring, recordkeeping, reporting, and testing.
3. For rules and general permits that apply to categories of sources, practical enforceability additionally requires that the provisions: (i) Identify the types or categories of sources that are covered by the rule of general permit; (ii) Where coverage is optional, provide for notice to the reviewing authority of the source's election to be covered by the rule or general permit and (iii) specify the enforcement consequences relevant to the rule of general permanent.

Each of these is consistent with the requirements that EPA has finalized for legally and practicably enforceable under OOOOb and OOOOc EG. The criteria of legally and practicably enforceable proposed for this rule are the sector-specific application of prior efforts to define the terms in guidance documents in Title V and elsewhere, including in the example cited by the commenter.

Comment: Commenter (0599-MS) stated that the additional prescriptive requirements in the proposed definition would require permitting authorities to re-write existing permit conditions to exactly match the language in the proposed rule.

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<sup>23</sup> 40 CFR 49.16.

Response I-9-10: The EPA disagrees that our proposal necessitates that all existing permits be re-written. These specific criteria do not retroactively apply to permit limits or other requirements that owners and operators had previously relied upon in determining OOOO or OOOOOa applicability to their storage vessels. The criteria will apply to determining OOOOb applicability to new storage vessels, i.e., those for which construction, reconstruction or modification commenced after December 6, 2022 (the supplemental proposal date) and for determining applicability for existing storage vessels covered by the EG OOOOc. For new storage vessels already constructed, reconstructed or modified before the effective date of this final rule, to the extent their owners or operators decided to obtain legally and practicably enforceable limits to cap the potential emissions from their storage vessels below the proposed OOOOb applicability thresholds, they were on notice of EPA's proposed LPE criteria when obtaining such limits. With regard to existing sources, as states develop their state plans to implement OOOOc EG, they may adopt these criteria for legally and practicably enforceable emission limitations or develop their own criteria as long as they are equivalent to the EPA criteria (i.e., equally effective in capping potential emissions) for purposes of determining storage vessel designated facility status under their plans. States that use permit-by-rule or general permits should evaluate the substance of these rules to ensure that those rules incorporate provisions that achieve the intent of the final rule with respect to legally and practicably enforceable limitations.

Comment: Commenter (0599-MS) provided specific comments on the proposed legally and practicably enforceable emission limitations definition. The commenter states that they understand the proposed definition to state that only those limits that include the elements proposed will be considered "legally and practicably enforceable," for purposes of determining the potential for VOC emissions from a single storage vessel or tank battery, and thus applicability (or non-applicability) of each single storage vessel or tank battery as an affected facility under the rule. The commenter recommends that other factors, including the maximum capacity under the physical and operational design and state regulations that include rolling 12-month emission limits (without a specific throughput limitation), should be considered legally and practically enforceable.

Response I-9-11: The EPA agrees with the commenter that the maximum capacity under the physical and operational design may be considered to be quantitative production limits and quantitative operational limits and therefore legally and practicably enforceable, if the other criteria of legally and practicably enforceable are met. The EPA agrees that state regulations that include rolling 12-month emission limits are sufficient to be practicably enforceable language without a specific throughput limitation, provided that a record of how the standard was met is produced every 30 days as part of the annual rolling average recording system, and as long as the operational, monitoring, recordkeeping, and reporting elements of legally and practicably enforceable limits are also met.

Comment: Commenters (0820-Pioneer, 0808-API) commend EPA for proposing to clarify applicability of the storage vessel emissions standards by defining the term "legally and practicably enforceable limit," but state that this issue has implications that go far beyond the narrow confines of the storage vessel standard and suggests that EPA defer final action on the

proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected Clean Air Act (CAA) programs.

Response I-9-12: The EPA does not see a need to delay finalizing the definition of a “legally and practicably enforceable limit” that is specific to storage vessel applicability determination in this rule. The legally and practicably enforceable criteria we proposed are specific to oil and gas storage vessels. EPA anticipates that any subsequent action on defining legally and practicably enforceable limits meant to cover a wider variety of source categories would be more general and, as such, would not conflict with the category-specific criteria tailored to oil and gas storage vessels in this final rule. EPA could also in that later action address potential conflicts, if any, with the category specific definition for a LPE limit in this oil and gas rule.

Comment: Commenters (0820-Pioneer, 0808-API) are concerned that addressing legally and practicably enforceable specifications in a piecemeal, rule-by-rule fashion will ultimately cause confusion and potential inconsistency across EPA's CAA stationary source programs: from major source permitting under New Source Review (NSR)/Prevention of Significant Deterioration (PSD), to the Title V operating permit program, to all manner of federal and state emissions control programs (of which CAA§ 111 is just one). The commenters state that what constitutes an acceptable and effective "legally and practicably enforceable limit" has been an open question since the mid-1990s, when the prior "federal enforceability" requirement was remanded or vacated across EPA's programs. See *National Mining Ass'n v. EPA*, 59 F. 3d 1351 (D. C. Cir. 1995); *Chemical Mfrs. Ass'n v. EPA*, 70 F. 3d 637 (D.C. Cir. 1995); *Clean Air Implementation Project v. EPA*, 1996 WL 393118 (1995). The commenters note that EPA once announced its intent to conduct a comprehensive rulemaking to address the holdings in these cases but has not yet taken action almost 30 years after the decisions were handed down.<sup>24</sup> The commenters state that affected facilities and states now have years of experience implementing the NSPS OOOO and OOOOa storage vessel standards, including substantial experience in crafting appropriate emissions limitations to govern applicability of these standards. The commenters believe that creating new mandatory procedural requirements is unnecessary, given that no systemic problem has emerged during this long implementation period and that such requirements would add to the cost and burden of implementing these standards, without delivering any commensurate benefit.

Commenter (0820-Pioneer) is further concerned that the proposed elements could inadvertently call into question existing permitting and regulatory regimes that do not specifically include the parameters proposed by EPA. The commenter states that the Texas Commission on Environmental Quality (TCEQ) permits appear to show all of the proposed elements, but the proposed requirements are vague. The commenter believes that the first requirement, "*quantitative production limit and quantitative operational limit*" is shown in the state TCEQ permit, but requests clarification on EPA's intent. The commenter asks if operators need to obtain a federal permit on top of the state permit and strongly recommends that EPA specify that the certified state permit suffices in demonstrating that tank batteries are under the required threshold limits of either 6 or 20 tpy. The commenter also recommends that the air permitting

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<sup>24</sup> Memorandum from John S. Seitz to Regional Office Addressees, Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit (Jan 22, 1996).



State Implementation Plan (SIP) that was approved by EPA and TCEQ's delegation to run the permitting program should provide the assurances EPA needs to rely on the state agency.

Response I-9-13: See Response I-9-8. The new criteria will not be applied to sources subject to OOOO and OOOOa, and apply going forward to sources subject to OOOOb. The criteria will apply to designated sources under OOOOc in the future after state rulemaking is pursued under CAA section 111(d).

Comment: Commenter (0820-Pioneer) requests that EPA define "*parametric limits*" to mean the ongoing monitoring of production.

Response I-9-14: "Parametric limits" refers to limits on a parameter that can act as a reliable indicator of an emissions-producing (or emissions-reducing) activity or process. As the commenter suggests, such limits could include ongoing monitoring of production and/or operational limits.

Comment: Commenter (0938-TXOGA) states, that beyond citing to the holding of *National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 1995)<sup>25</sup> and statements in the November 2021 Proposal that certain limits do not adequately serve to limit the emissions from storage tanks. EPA does not provide record evidence that a new definition of "legally or practicably enforceable limits" is needed. The commenter states that while EPA referenced example permit limits that "do not require a reduction in emissions; they are often self-imposed or of such a general nature as to be unenforceable or otherwise lack measures to assure the required emission reduction,"<sup>26</sup> EPA does not cite to any specific permits. Although the commenter agrees with *National Mining's* holding that unenforceable voluntary actions do not serve to limit PTE, the November 2021 Proposal record does not indicate that the provisions EPA proposes are necessary, and the commenter is concerned that the proposed requirements go beyond what is necessary.

Response I-9-15: The EPA cannot disclose information related to ongoing enforcement actions. Further, the EPA cannot disclose confidential information shared during the course of settlement negotiations. Excerpts of specific permits that the EPA has reviewed and determined to be lacking legally and practicably enforceable limits include:

Permit 1—Applicable Emissions Limitations or Control Measures.

- In order to comply with the tons per month emission limit, utilize one or more of the following controls: Use of add-on control (vapor recovery, flare or equivalent)

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<sup>25</sup> See also *Nat'l Mining Ass'n*, 59 F.3d at 1364 ("As presented in its briefs, EPA's core justifications for its federal enforceability policy are the need to avoid the administrative burden that EPA would have to bear were it obligated to evaluate the effectiveness of state and local controls and the desirability of uniformity in environmental enforcement. These, of course, are not illegitimate agency objectives. Administrative problems, in particular, can under certain circumstances inform an agency's construction of imprecise statutory language. See *Drummond Coal Co. v. Hodel*, 796 F.2d 503, 507 (D.C. Cir. 1986). Here, however, EPA would have us accept a rather strained interpretation of the statute based on what appears to be only its unwillingness to evaluate any state or local controls that are not federalized.").

<sup>26</sup> 86 FR 63201.

to control emissions from storage vessels as needed to comply with the annual VOC emission limitations.

- The permittee accepts a voluntarily limit to restrict the potential VOC emissions from each storage vessel to less than 6 tons per year.

In Permit 1, the control device is not specified and the permit terms do not specify a destruction rate efficiency, combustion rate, or availability for a vapor recovery unit. The provision also does not specify emissions testing, operational parameter monitoring, inspection requirements or recordkeeping or reporting requirements for the add-on control. Additionally, the terms “voluntarily limit” in the second provision do not include site-specific emissions calculations that demonstrate that this storage vessel is below 6 TPY. The terminology also indicates that controlling emissions below 6 TPY of VOCs is not a requirement.

#### Permit 2—Combustor/Flare Requirements

- All exhaust gas/vapors from the oil storage tanks shall be routed to the operating combustor/flare.
- The combustor/flare shall operate with no visible emissions.
- Visual determination of smoke emissions from flares shall be conducted according to 40 CFR 60, Appendix A, Method 22.

In Permit 2, a destruction rate efficiency of 95% or greater is not specified. There is no testing requirement for the control device, no continuous pilot light monitoring or inspection requirement, no indication of how frequently Method 22 inspections must be conducted, and no recordkeeping or reporting requirements. Both Permit 1 and Permit 2 demonstrate provisions from permits that do not have operational or parametric limits and therefore, that the EPA has determined not to be legally and practicably enforceable.

Comment: Commenter (0938-TXOGA) requests that EPA adequately explain and examine how these state limits are not applying adequate controls, before requiring such burdensome production and operational restrictions on such permit limits.<sup>27</sup> The commenter provides specific comments on the definition. First, the commenter states that the suggested definition seemingly conflicts with how PTE is calculated for storage vessels under the rule, and specifically, the regulatory standard for “maximum average daily throughput,”<sup>28</sup> where emissions determinations are to be based on a legally and practicably enforceable limit to keep emissions under 6 tpy, or otherwise based upon an analysis of 30 days of production. The commenter states that EPA appears to be reversing this position in the preamble (without identifying that they are taking such action) and the suggested definition for “legally and practicably enforceable limits”

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<sup>27</sup> As stated by the D.C. Circuit in *National Mining*, “By no means does that suggest that Congress necessarily intended for state emissions controls to be disregarded in determining whether a source is classified as “major” or “area” under that national standard. Nor did Congress mandate that EPA assume the administration and enforcement of all governmental efforts at emissions limits. If such administration and enforcement is necessary to ensure that controls are effective in the context of the extant regulatory environment, EPA has certainly not made that case and has not indicated how that consideration supports its claim that its interpretation of the statute is reasonable.” 59 F.3d at 1365.

<sup>28</sup> The commenter (0938-TXOGA) cites to §60.5430a, definition of “maximum average daily throughput.”

confounds the method for a determination of “maximum average daily throughput,” because application of the definition will require sources that take such a limit to employ calculations and monitoring on an ongoing basis (e.g., to revise PTE calculations to reestablish a production or operational limit).

Response I-9-16: EPA takes issue with the commenter’s implication that legally and practicably enforceable criteria “seemingly conflicts’ with the threshold determination to apply standards to storage vessels. The standards could not more clearly state that upon summing the emissions over a 30-day period, the sum may be reduced by the reduction determined by the control efficiency of control devices specified in a legally and practicably enforceable emission limitation. We disagree with the assertion that a demonstration of ongoing compliance with an emission limit through parametric monitoring constitutes a re-determination of affected facility status. However, if the potential for VOC or methane emissions is limited through a legally and practicably enforceable limit, there will be a requirement to conduct on-going monitoring and compliance determinations with respect to those limits. The EPA has asserted in prior guidance<sup>29</sup> and re-asserts here in the form of new requirements specific to the oil and gas industry that for periodic monitoring of ongoing compliance to be practicably enforceable, the averaging period may be no more than 30 days. As discussed in Response 1-9-17, EPA agrees that a rolling 12-month average is an acceptable alternative to a month-by-month determination. See also the response to I-9-15.

The EPA’s record of enforcement reflects that state limits as they have been implemented have in select cases not resulted in adequate control of emissions. The EPA cannot disclose information related to ongoing enforcement actions. The EPA can refer to settled enforcement cases with oil and gas operators that hold state general permits that lack sufficient substance to provide legally and practicably enforceable limits, such as unenforceable voluntary actions that do not serve to limit PTE below NSPS applicability thresholds. Commenters may review publicly available settlement documents of completed enforcement cases with oil and gas operators for specific examples.

Comment: Commenter (0938-TXOGA) further states that EPA suggests in the list of “legally and practicably enforceable limits” that the averaging period would need to be “equal to or less than 30 days,” when the initial demonstration using “maximum average daily throughput” was established based on 30 days of production. The commenter states that a tpy limit typically is established based on a rolling 12-month sum, and this was plainly authorized under the prior version of the regulations; therefore, the commenter states, there is no question that limits of this form have long been considered by EPA to be both legally and practically enforceable. The commenter states that by making the limits tied to PTE determined from 30 days or less of production, the applicability threshold is dramatically more stringent and expands applicability, than would otherwise be the case. The commenter requests that EPA explain the significant change since the November 2021 Proposal did not provide adequate explanation as to why it is necessary. Further, the commenter requests that EPA explains why a 30-day (or less) averaging period is required, because the commenter does not believe it is required for legal and practical

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<sup>29</sup> Memorandum from John S. Seitz to Regional Office Addressees, Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit (Jan 22, 1996).

enforceability. The commenter states that further explanation by EPA is needed to be able to provide the required meaningful opportunity to comment.

Response I-9-17: The EPA agrees that a rolling 12-month average is an acceptable alternative to a month-by-month determination, where the rolling 12-month average is supported by 30-day subtotals, and redetermined every month. EPA guidance<sup>30</sup> clearly states that for an emission limitation to be legally and practicably enforceable, the monitoring period must be no more than a 30-day period of production. A tons-per-year cap alone, using 12 months of production, is insufficient to be considered legally and practicably enforceable under OOOO and OOOOa, specifically because such a provision would be unenforceable for the initial 11 months of production. When establishing permit limits on production or operation, EPA believes that such limits should not exceed 30 days. EPA also points out that a violation of a 12-month standard without any prior interval to verify compliance has the potential to create a full year of non-compliance and associated penalties for failure to demonstrate ongoing compliance.

Comment: Commenter (0938-TXOGA) states that they do not dispute that sources choosing to accept restrictions on emissions below the applicability threshold must ensure that they are both legally and practically enforceable, but EPA seems to impugn generally its state partners' ability to issue enforceable limits in permits and further, the language provided in the preamble goes well beyond what is needed for such a limit to be established. The commenter references the TCEQ comments on the 2021 November Proposal and states that TCEQ issues limits that are both practically and legally enforceable, and which also is true for other oil and gas producing states where commenter's members operate. The commenter states there is no reason to think that experienced state permitting authorities who have been delegated authority to implement NSPS requirements through their Title V programs and under section 111 of the CAA since their Title V programs were approved in the 1990s have been unable to assess the information needs or that their permits would be inadequate.

Response I-9-18: EPA disagrees that the criteria for legally and practicably enforceable goes beyond what is necessary to demonstrate ongoing compliance. EPA responded in Response I-9-15 with examples of how specific permits failed to provide sufficient provisions for enforceability. EPA responded in I-9-12 and I-9-9 how the criteria are tailored to sources subject to OOOOb and OOOOc EG, and are consistent with guidance in other programs including Title V and NSR, and provided an example of that consistency when compared to similar provisions under 40 CFR 49.16. EPA responded in I-9-8 that EPA has agreed with commenters that the criteria are not a reiteration of guidance, but new regulatory criteria that our enforcement history demonstrates are necessary going forward for sources to have the certainty of what requirements will apply to them.

We point out that the provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source affected facilities under OOOOc EG, and are not retroactively applicable to OOOO or OOOOa

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<sup>30</sup> Memorandum from John S. Seitz to Regional Office Addressees, Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit (Jan 22, 1996).

sources. The EPA enforcement cases to date have relied on EPA guidance and the provisions of OOOO and OOOOa, as applicable and will continue to do so for those enforcement cases.

EPA is not asserting that states universally have been unable to assess the information needs or that their permits would be inadequate. Rather, enforcement inspections have led us to conclude that specific LPE criteria are needed to ensure that tanks with potential emissions at or above the thresholds are subject to OOOOb/OOOOc.

Comment: Commenter (0938-TXOGA) states that EPA should revise or eliminate its proposed definition to remove references to production limits and a need to recalculate, on an ongoing basis, the PTE for a storage tank, because such limits are addressed by the manner in which EPA requires storage vessel sources which do not take a permit limit to determine of “maximum average daily throughput.” The commenter notes that in cases where a permit limit is taken (as EPA correctly notes) the burden is on the source to comply and demonstrate that it complies with the limit.

Response I-9-19: EPA clarifies that a source will not need to recalculate, on an ongoing basis, the PTE for a storage tank. The potential to emit calculation for the purpose of determining applicability is a one-time occurrence (absent any actions that would meet the definition of modification or reconstruction) to determine applicability within 30 days of startup. However, if the potential for VOC or methane emissions is limited through a legally and practicably enforceable limit, such limit would include a requirement to conduct on-going monitoring and compliance determinations with respect to those limits. When establishing permit limits on production or operation, EPA believes that such limits should not exceed 30 days. This requirement allows for EPA to determine compliance more quickly and serves to protect the regulated community from extended periods of non-compliance with resulting multi-day penalties. For example, measurement for 12 consecutive months would allow the source and EPA to determine, after 12 months, at what point a violation may have occurred or began. In the absence of such data, it would not be clear at what point over the 12 months a violation may have begun.

Comment: Commenter (0938-TXOGA) states that to the extent EPA continues with the November 2021 proposed approach, it is important that, if a previously issued limit needs to be revised to meet the final rule’s requirements, that sources that have complied with and operated below the 6 tpy applicability threshold should, as a matter of due process, have the opportunity to amend their permits without threat of enforcement. The commenter requests that EPA clarify that facilities currently operating below the 6 tpy threshold pursuant to permit limitations on their PTE are not subject to the proposed legally and practicable enforceability requirements until their next permit renewal or two years from the effective date of the final rule, whichever is later.

Response I-9-20: See Response I-9-18.

Comment: Commenter (0776-CDPHE) states they are concerned that EPA’s November 2021 proposed criteria will prompt the need to revise existing permits and/or adopt duplicative and unnecessary recordkeeping and reporting regulations in order to ensure compliance with the NSPS or to submit an approvable CAA 111(d) plan. The commenter explains that Colorado has

relied both on Regulation 7<sup>31</sup> and minor source permits as the basis of operators' limiting potential to emit below the applicable control thresholds. Further, the commenter is concerned that EPA's November 2021 Proposal fails to recognize the opportunity to use technologies and methods that ensure better control and accuracy of measurement, and instead relies on traditional calculation methodologies and recordkeeping/reporting. Specifically, the commenter provides comments on particular elements of the proposed definition of "legally and practicably enforceable:"

*(ii) - an averaging time period for the production limit that is equal to or less than 30 days.* The commenter specifically is concerned with these criteria given the typical production curve associated with new well production facility operations, explaining that these facilities typically have high production during the first several months before reaching a steadier production rate later in the life of the well. The commenter states that this production decline curve represents substantial variation which makes monthly or shorter production limits impractical, as acknowledged in the June 13, 1989, Memorandum, "Guidance on Limiting Potential to Emit in New Source Permitting" which states on page 9:

*EPA recognizes that in some rare situations, it is not reasonable to hold a source to a one month limit. In these cases, a limit spanning a longer time is appropriate if it is a rolling limit. However, the limit should not exceed an annual limit rolled on a monthly basis. EPA cannot now set out all-inclusive categories of sources where a production limit longer than a month will be acceptable because every situation that may arise in the future cannot now be anticipated. However permits where longer rolling limits are used to restrict production be issued only to sources with substantial and unpredictable annual variation in production...*

*(iii) - a compliance demonstration or mandatory initial performance testing requirement* that is not flexible enough to account for the different types of compliance demonstrations that should be made. The commenter requests an approach that leaves it to the state agency to determine what is a sufficient compliance demonstration; for example, state agencies should not be required to mandate an initial performance test on all air pollution control equipment used to establish practicably enforceable limits and instead should be allowed to use sound judgment on when to require initial performance tests.

*(v) - prescriptive recordkeeping requirements.* The commenter requests that states should have the ability to determine what records are sufficient for the state to determine whether an operator is in compliance.

*(vi) - mandatory, and prescriptive, periodic reporting.*

The commenter (0776-CDPHE) explains that Colorado already has periodic reporting of emissions and other data (e.g., emission factors, gas speciation, performance testing information)

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<sup>31</sup> Colorado notes that its control thresholds for storage tanks (as opposed to storage vessels) is 2 tpy VOC (and 4 tpy VOC in the state's ozone SIP). See Regulation 7, Part D, Sections I.D.3 and II.C.1.c.

and they should not be obligated to amend its regulations to include additional, and potentially duplicative and less efficacious, reporting. The commenter requests that EPA not mandate periodic reporting and that EPA clarify that legally and practicably enforceable limits established through permits and associated records may be reported upon request of the agency rather than require records to be submitted on a mandatory periodic schedule. The commenter believes this would ensure states have the ability to focus their compliance resources on targeted compliance evaluations.

Response I-9-21: See Response I-9-17 regarding rolling 12-month averages. The EPA continues to believe that measuring and recording throughput each 30-day period towards showing continuous compliance with a 12-month rolling annual standard is reasonable for these sources. The commenter points out that storage vessel throughput is typically higher in the initial months after the startup of production and tends to be lower and more consistent over time. The EPA does not see how such falling production rates would pose a problem for determining compliance with a limit that would have been established during the highest periods of a well's production and where such limits are intended to limit a source's potential for emissions. The EPA therefore considers it practicable to be able to review the most recent 30 days of data upon inspection to ensure continuous compliance with an enforceable limit over the previous 12 periods of 30 days.

We also point out that the provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source designated facilities under OOOOc, and are not retroactively applicable to OOOO or OOOOa sources. The EPA enforcement cases to date have relied on EPA guidance and the provisions of OOOO and OOOOa, as applicable, and will continue to do so to determine whether legally and practicably enforceable limits are met in permits or other requirement established under Federal, state, local, or tribal authority.

The EPA agrees with the commenter with respect to different methods of showing compliance. The EPA has elaborated here in the response to comments and preamble to better explain the intent of periodic monitoring for compliance. See Responses I-9-15 with examples of how specific permits failed to provide sufficient provisions for enforceability. EPA responded in I-9-12 and I-9-9 how the criteria are tailored to sources subject to OOOOb and OOOOc EG, and are consistent with guidance in other programs including Title V and NSR, and provided an example of that consistency when compared to similar provisions under 40 CFR 49.16. EPA responded in I-9-8 that EPA has agreed with commenters that the criteria are not a reiteration of guidance, but new regulatory criteria that our enforcement history demonstrates are necessary going forward for sources to have the certainty of what requirements will apply to them.

Comment: Commenter (0456-WDNR) recommends that EPA not propose a definition of a "legally and practicably enforceable limit" for purposes of determining whether a single storage vessel or tank battery is an affected facility, because establishing such a definition in the proposed rule could have significant impact on the implementation of CAA sections 111(b) and 111(d) that goes beyond the oil and natural gas sector. The commenter states that the definition could also affect how NSR and operating permit programs operate in the states. The commenter suggests that past EPA guidance on legally and practicably enforceable limits has not provided the needed clarity to ensure consistency among the states in synthetic-minor permitting and notes

that the EPA Office of Inspector General Report on EPA Oversight of Synthetic-Minor-Source Permitting (Report No. 21-P-0175) published in July 2021 recommended that EPA update its practical enforceability guidance, and develop and issue new guidance that includes key EPA expectations for synthetic-minor-source permitting. The commenter recommends that EPA update its guidance on legal and practical enforceability and seek public comment on the updated guidance before proposing any definitions of a “legally and practicably enforceability limit” that would be included in a federal standard.

Commenter (1267-CA AG *et al.*) suggests that EPA consider states’ existing frameworks for a “legally and practically enforceable limit” to ensure that states are not unnecessarily required to adopt duplicative recordkeeping and reporting regulations nor are forced to use alternative technologies and methods in a situation where state regulations ensure better control and accuracy than the November 2021 Proposal.

Response I-9-22: EPA disagrees that changes to the NSPS will affect how NSR and Title V operates among states. EPA responded in I-9-12 and I-9-9 how the criteria tailored to sources subject to OOOOb and OOOOc EG, are consistent with guidance in other programs including Title V and NSR, and provided an example of that consistency when compared to similar provisions under 40 CFR 49.16. EPA responded in I-9-8 that EPA has agreed with commenters that the criteria are not a reiteration of guidance, but new regulatory criteria that our enforcement history demonstrates is necessary going forward for sources to have the certainty of what requirements will apply to them.

The EPA has opted to promulgate legally and practicably enforceable criteria specific to oil and gas storage vessels over issuing additional guidance. With the next generation of sources subject to OOOOb and existing sources to be designated subject to OOOOc and a new standard for methane, EPA considers this the opportune time to provide greater clarity and certainty than guidance can provide.

The EPA has agreed with comments to the effect that the promulgation of a methane standard applicable to the sources affected by this final action may require amendments to permits, permits by rule, minor source, or synthetic minor permits. The EPA is choosing to add regulatory certainty to describe legally and practicably enforceable emissions limitations now because of the number of changes to the NSPS and the EG finalized in this action. If the EPA were to choose to issue another round of guidance, states and sources would not have the same level of certainty as to what EPA considers legally and practicably enforceable for the next generation of sources. This level of specificity and certainty will serve to guide states as they consider how to apply these criteria through state requirements promulgated under OOOOc EG and through permits issued for OOOOb sources.

Comment: Commenter (0844-EDF *et al.*) states that to the extent that EPA retains a potential to emit based on legally and practicably enforceable limits, they support using the factors stated by EPA. Further, the commenter suggests that EPA should include in its definition of “legally and practicably enforceable limits” a requirement that operators report actual deviations from normal operations for a source. The commenter notes that if a large emission event occurs, it is likely that the “potential” that is articulated in a permit has been exceeded, and therefore, in order to



fully ensure that the “potential” is represented, the deviation should be reported in a manner that will allow EPA to determine whether the permit limit was exceeded. The commenter further suggests, that along with the type of deviation, the actual deviation report should include the date and time that the deviation was discovered, the date and time of the last confirmed normal operation, and the parametric data that accompanied that source during those times the deviation occurred.

Response I-9-23: The comment is focused on deviations, malfunctions, and the resulting emissions. Emissions that result from malfunctions are not the result of normal operation and are not contemplated in a storage vessel’s maximum potential to emit, and therefore the comment is beyond the scope of the discussion of legally and practicably enforceable emissions limitations. See general discussion in section IV.J.1.a of the December 2022 Supplemental Proposal regarding legally and practicably enforceable limits.<sup>32</sup>

Comment: Commenters (0817-GPA, 0832-NMED) request that EPA allow additional time to comply with proposed NSPS OOOOb requirements for storage vessels (and for other equipment). Commenter (0817-GPA) explains that due to the changes in definition of “legally and practicably enforceable,” compliance will turn on the speed with which state regulatory agencies can re-open and re-issue or renew permits, not on any action by regulated owners and operators. Further, if existing source applicability is based on methane emissions, each facility would need to revise its permit to either include methane emission rates or enforceable limits for an existing control. Such updates to permits to include a separate methane emissions limit, the commenter points out, will necessitate more time for compliance, as midstream companies cannot control the speed with which permitting authorities will re-open or re-issue permits to include methane limitations for the first time. The commenter suggests that for some states, this could require revisions to tens of thousands of permits, and it may take several years for midstream companies to receive revised or reissued permits. The commenter recommends that EPA require compliance only upon the issuance of a new or revised permit from the permitting authority rather than establishing an arbitrary time limit for compliance as it would be unfair to subject operators to enforcement actions merely because state permitting agencies could not issue revised permits at the pace EPA desired.

Response I-9-24: See Response I-9-8.

Comment: Commenter (0832-NMED) recommends that EPA provide sufficient time for owners and operators to comply with the control requirements, as part of a phased compliance timeline. The commenter explains that during the new NMED Part 50 rulemaking hearing, affected owners and operators and industry stakeholders raised concerns about having sufficient numbers of control devices available to implement controls simultaneously. To address this, NMED Part 50 proposes a phased compliance deadline in order to ensure there are sufficient control devices available over the course of the compliance timeline. The commenter states that the lower applicability thresholds for both new and existing vessels, with a reasonable compliance

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<sup>32</sup> 87 FR 74800 (December 6, 2022).

deadline, would result in important additional emissions reductions from new and existing storage vessel affected facilities.

Response I-9-25: The final NSPS OOOOb requires compliance with the 95 percent emission reduction standard within 30 days after startup of production or within 30 days after reconstruction or modification of the storage vessel affected facility for each storage vessel affected facility located at a well site or centralized production facility. See §60.5370b(a)(3). For storage vessel affected facilities located at a compressor station or onshore natural gas processing plant, the final NSPS OOOOb requires compliance prior to startup of the facility or within 30 days after reconstruction or modification of the storage vessel affected facility. The requirements that EPA is finalizing do not apply to existing sources before states have the opportunity to submit 111(d) implementation plans after state rulemaking takes place to reflect the emission guidelines. EPA has allowed states 18 months to carry out state rulemaking activity to adopt the appropriate emission guidelines and standards. In addition to the 18 months, EPA has recommended that states adopt compliance deadlines within 36 months, providing over 4 years for existing sources to adapt their systems to new federal and state standards.

Comment: Commenter (0817-GPA) asserts that, contrary to what the November 2021 Proposal appears to presume, the term “legally and practicably enforceable” is already defined. The commenter cites the preamble to the proposed rulemaking, *Prevention of Significant Deterioration and Nonattainment New Source Review: Debottlenecking, Aggregation, and Project Netting*, 71 Fed. Reg. 54,235 (Sept. 14, 2006) which explained the term as follows:

“Enforcement as a practical matter” will be achieved if a requirement is both legally and practicably enforceable. A requirement is “legally enforceable” if some authority has the right to enforce the restriction ... practicable enforceability for a source-specific permit will be achieved if:

1. A technically accurate limitation and the portions of the source subject to the limitation;
2. The time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits);
3. The method to determine compliance, including appropriate monitoring, recordkeeping, and reporting.

For rules and general permits that apply to categories of sources, practicable enforceability additionally requires that the provisions:

1. Identify the types or categories of sources that are covered by the rule;
2. Where coverage is optional, provide for notice to the permitting authority of the source’s election to be covered by the rule;
3. Specify the enforcement consequences relevant to the rule.

71 Fed. Reg. at 54,240, n. 13.

The commenter (0817-GPA) further provides that EPA later codified the definition of “legally and practicable enforceable,” with revisions from its prior interpretation, in its regulations for the *Federal Minor New Source Review Program in Indian Country*. 76 Fed. Reg. 38,748 (July 1, 2011). That definition is:

Enforceable as a practical matter means that an emission limitation or other standard is both legally and practicably enforceable as follows:

(1) An emission limitation or other standard is legally enforceable if the reviewing authority has the right to enforce it.

(2) Practical enforceability for an emission limitation or for other standards (design standards, equipment standards, work practices, operational standards, pollution prevention techniques) in a permit for a source is achieved if the permit’s provisions specify:

- i. A limitation or standard and the emissions units or activities at the source subject to the limitation or standard;
- ii. The time period for the limitation or standard (g., hourly, daily, monthly, and/or annual limits such as rolling annual limits) and
- iii. The method to determine compliance, including appropriate monitoring, recordkeeping, reporting and testing.

(3) For rules and general permits that apply to categories of sources, practical enforceability additionally requires that the provisions:

- i. Identify the types or categories of sources that are covered by the rule or general permit;
- ii. Where coverage is optional, provide for notice to the reviewing authority of the source’s election to be covered by the rule or general permit and
- iii. Specify the enforcement consequences relevant to the rule or general permit.

40 C.F.R. §§ 49.152, 49.167.

The commenter (0817-GPA) contends that there are several differences between EPA’s current definition of the term and the revised definition EPA has outlined in the November 2021 Proposal—but without providing any legitimate basis for proposing to change long-standing practice and regulation:

- EPA’s November 2021 Proposal eliminates the use of “other standards,” defined in current law as including “design standards, equipment standards, work practices, operational standards, [and] pollution prevention techniques.” These are sensible ways in

which requirements can be made enforceable as a practical matter and should be retained. Instead, EPA apparently proposes to allow only “[a] quantitative production limit and quantitative operation limit(s) for the equipment, or quantitative operation limits for the equipment.” 86 Fed. Reg. at 63,201. EPA offered no explanation in the November 2021 Proposal for why it proposed to change its position to exclude the use of design standards, equipment standards, work practices, operational standard, or pollution prevention techniques.

- The existing definition specifically allows for “hourly, daily, monthly, and/or annual limits, such as rolling annual limits.” Yet, where production limits are used, the November 2021 Proposal mandates an averaging time “that is equal to or less than 30 days.” The November 2021 Proposal does not explain the basis for requiring 30 days or less and does not explain why it is rejecting its current allowance of other limits, including a rolling annual limit that has often been included in permits and settlement documents. An annual or 12-month rolling average affords more flexibility and thereby minimizes the unduly prescriptive burden of a shorter averaging time, while still providing a mechanism for practical enforceability.
- Under the current definition, permitting authorities must determine the appropriate “method to determine compliance, including appropriate monitoring, recordkeeping, reporting and testing.” The November 2021 Proposal would require that, where a control device is used, it must be subject to an initial performance test “that establishes the parametric limits.” EPA again provides no explanation as to why it is proposing to specifically require a performance test and again offers no analysis of the additional benefit and cost of this change, a change that eliminates the discretion that long has been the well-established approach granted to permitting authorities in accordance with the fundamental value of cooperative federalism established by the Clean Air Act.
- The November 2021 Proposal also appears to raise conflicts with existing regulations. The proposed definition would appear to hold that combustors, certified by EPA as compliance with NSPS OOOOa, and compliant flares under 40 C.F.R. § 60.18, would no longer be recognized as valid. If EPA is proposing to rescind these existing regulations it should say so explicitly and provide an explanation of why these methods are no longer valid.
- The November 2021 Proposal also would deviate from the current definition in that it is proposing to require “ongoing monitoring of the parametric limits” to “demonstrate[ ] continuous compliance with the production and/or operational limit(s).” This is another instance of eliminating the discretion of permitting authorities. Here, EPA apparently is proposing to require a continuous emission or other continuous monitoring requirement without explanation or consideration of any other potential standards, such as design or work practice standards that have long been established as a fully effective approach. Again, the November 2021 Proposal does not offer an explanation for why this change would be made.
- EPA also ignores and would apparently eviscerate the long-standing practice of recognizing permits by rule or general permits as legally and federally enforceable. A significant number of midstream sources rely on these types of permits, and have done so for decades, but the November 2021 Proposal appears to eliminate them sub silentio and

without any reasoned explanation. EPA should clarify its position on the use of permits by rule and general permits.

Response I-9-26: The EPA disagrees that the criteria do not allow the use of design standards, equipment standards, work practices, operational standard, or pollution prevention techniques. For example, a design standard that limits production by physical limitation to a known and documented quantity, under appropriate operations conditions, constitutes a legally and practicably enforceable limit. See Response I-9-17 for a discussion of rolling averages for one year. EPA disagrees that the criteria for legally and practicably enforceable limits conflicts with the requirements related to enclosed combustion devices. The enclosed combustion devices that have been tested by the manufacturer must comply with continuous parametric monitoring requirements. Data showing the device has been operated within those parameters would be part of what EPA would use to verify adherence to the legally and practicably enforceable limit. Likewise, EPA did not propose that a flare designed and operated in accordance with 40 CFR 60.18 would no longer be a valid control device. EPA proposed continuous monitoring requirements for flares to ensure the flares meet the requirements outlined in the part 60 General Provisions on an ongoing basis.

The legally and practicably enforceable specifications provided by this rule are specific to oil and gas storage vessels. Nothing in this rule prohibits permits by rule or general permits from providing legally and practicably enforceable requirements that a source can take into account when calculating its potential emissions, provided those LPE requirements meet the specifications provided by the rule.

Comment: Commenter (0817-GPA) asserts that EPA's purported justification for the new definition is flawed. The commenter states that EPA's attempts to justify its November 2021 Proposal to define "legally and practicably enforceable," by stating that it has "learned that numerous owners and operators claim that their storage vessels are not affected facilities" and EPA disagrees. 86 Fed. Reg. at 63,201. However, they suggest that EPA has not offered any actual record-based evidence to support its statement. They add that EPA further states that it reviewed "the limits considered by these" unspecified "facilities" in unspecified jurisdictions and EPA has "become aware that the limits do not require a reduction in emissions; they are often self-imposed or of such a general nature as to be unenforceable or otherwise lack measures to the required emission reduction." Id. By way of example, EPA claims that one permit "for a single storage vessel, does not contain any performance testing requirements, continuous or other monitoring requirements, recordkeeping or reporting, or other requirements that would ensure that emissions are maintained below the emissions limit in the permit." Id. According to the commenter, however, EPA does not, provide any of these examples for stakeholders to review. The commenter requests that EPA provide the details surrounding that cited example, so interested stakeholders may respond and comment.

Response I-9-27: The EPA cannot disclose information related to ongoing enforcement actions. The EPA can refer to settled enforcement cases with oil and gas operators that hold state general permits that lack sufficient substance to provide legally and practicably enforceable limits, such as unenforceable voluntary actions that do not serve to limit PTE below NSPS applicability thresholds. Commenters may review publicly available settlement documents of completed

enforcement cases with oil and gas operators for specific examples. EPA responded in Response I-9-15 with examples of how specific permits failed to provide sufficient provisions for enforceability.

Comment: Commenter (0817-GPA) notes that, even without the ability to review the single permit cited by EPA as justification, the November 2021 Proposal begins with erroneous assumptions that the commenter would urge EPA to reconsider before proceeding with this change. First, the commenter notes that permits limiting a potential to emit through various means (emission limits, work practice standards, operational limitations, design standards, *etc.*) do not “require a reduction in emissions.” They require emissions to stay below a certain ceiling. The commenter asserts that the current definition of “legally and practicably enforceable” does not require an emission reduction nor does EPA explain why it believes that an emission reduction is required for a limit on a facility’s potential to emit to be enforceable.

Response I-9-28: By “emissions reduction standard” EPA understands that the commenter is describing a numerical limit on emissions to the atmosphere. Legally and practicably enforceable limits which meet the specifications in this rule and which ensure that potential emissions are not above the NSPS applicability threshold, are acceptable. However, the purpose of any legally and practicably enforceable limit, which is used to limit emissions below the applicability threshold, is to result in a “reduction in emissions.” If the legally and practicably enforceable limit does not set a numerical limit on emissions to the atmosphere, the quantitative operational and quantitative production limits must reduce emissions.

Comment: Commenter (0817-GPA) contends that EPA should explain why the fact that a limit is “self-imposed” is a relevant factor, as all permits limiting a potential to emit are “self-imposed” in that operators request them from permitting authorities. This request is often accompanied by an offer to abide by binding and enforceable limits (emission limits, work practice standards, operational limitations, design standards, *etc.*) to reduce the facility’s potential to emit. By definition, this is “self-imposed” yet fully in accordance with the current definition of “legally and practicably enforceable.” The commenter states that, if EPA’s reference to “self-imposed” limits was intended to mean something different, then the commenter asks the Agency to clarify its position so stakeholders may comment. Moreover, before proceeding with this change in approach, the commenter asks EPA to also provide specific examples of the “self-imposed” limits it is finding, why it believes they are not legally and practicably enforceable, and sufficient supporting information so that interested parties can comment on EPA’s reasoning, such as information about the particular storage tanks, relevant permit terms, and the jurisdiction or issuing authority.

Response I-9-29: EPA believes there is confusion over what we meant by “self-imposed.” A self-imposed limit for which there is no means of enforcement, or no penalty for non-compliance is not legally or practicably enforceable. However, a limit that was requested by the permit holder and which is accompanied by binding and enforceable (as the commenter characterizes them) limits would be acceptable to take into account when calculating potential emissions, provided those limits meet the specifications of legally and practicably enforceable under the

NSPS. See response I-9-15 for anonymized examples of permits that EPA determined did not meet the criteria EPA requires for a limit to be legally and practicably enforceable.

Comment: Commenter (0817-GPA) asserts that EPA's claim in the November 2021 Proposal that its cited example lacks performance testing and continuous monitoring is misplaced, as neither is required for limits to be "legally and practicably enforceable". Indeed, the November 2021 Proposal does not identify any regulation, federal or state, that requires performance testing and continuous monitoring to ensure a limit is enforceable. Instead, the commenter suggests that the November 2021 Proposal appears to assume, without explanation, that the only "appropriate monitoring" is continuous emissions monitoring and the only "appropriate testing" is performance testing. Yet, the commenter explains that individual and general permits, as well as permits by rule, have required a wide array of monitoring and testing requirements to suit the wide array of emission sources that have taken a voluntary limit on their potential to emit. The commenter urges EPA to reconsider these well-established options and/or explain and document why it now finds all other forms of monitoring and testing to be deficient for all applications so that the public can understand why EPA is changing its position and can provide input and comment.

To the extent that there are genuine concerns with the permits EPA reviewed, such as overly vague terms that do not identify the limitation or standard or a complete absence of any type of monitoring, reporting, or recordkeeping obligations, then the commenter (0817-GPA) states that EPA has the authority to raise those issues with the delegated permitting authorities that issued the permits. Because EPA provided no details regarding the permits it reviewed, or the permitting authorities that issued the permits, the commenter notes that they cannot provide any further comment on the perceived deficiencies and requests EPA to provide this information for notice and comment before moving forward to apply any changes to this important framework. However, they adamantly believe that an operator should not be the subject of an enforcement action due to disagreements between EPA and the permitting authority over permit terms. The commenter provides that operators have a due process right to rely in good faith upon the permits issued to them by permitting authorities so long as the operator complies with the permit terms. See, e.g., *Wisconsin Resources Protection Council v. Flambeau Mining Co.*, 727 F.3d 700, 707 (7<sup>th</sup> Cir. 2013) ("even if Flambeau's permit were legally invalid, we cannot, consistent with the requirements of due process, impose a penalty on Flambeau for complying with what Wisconsin deemed a valid ... permit.").

Response I-9-30: There is no requirement in the NSPS or EG for a permitting authority to include all of the criteria EPA is proposing for the oil and gas sector regarding legally and practicably enforceable limits in its permits. Therefore, EPA has no disagreement with the permitting authority if permits do not include such limits, and indeed such permits may be sufficient to meet other state requirements. However, the concern is with holders of permits that lack legally and practicably enforceable limits who attempt to use those permits to limit their potential for emissions from applicability under the NSPS when in fact there is no legally and practicably enforceable restriction on the source's potential for emissions. Regarding the commenter's assertion that the legally and practicably enforceable monitoring criteria require continuous emissions monitoring, this is not true. Just as we explained that legally and

practicably enforceable limits do not require a numerical emissions standard, the monitoring of parameters, while continuous, do not have to continuously monitor emissions.

EPA is not adding regulatory language for legally and practicably enforceable limits in an effort to correct state permit programs. EPA enforces the NSPS as written and has chosen to add regulatory language for new affected sources under OOOOb to facilitate compliance on the part of owners and operators. EPA has obtained consent decrees for sources that failed to show compliance with the NSPS from owners and operators. The EPA did not obtain those consent decrees with state agencies.

To the commenters concern about enforcement action as a result of the terms of a permit, the EPA has expressed this concern in the past. See, e.g., 83 FR 52085 and 85 FR 57425. In addition, over the years, the EPA has expended extensive resources in enforcement actions to review permits, general permits, and permits-by-rule and found that for nearly in all cases, these permits or other requirements across an estimated 400 storage vessel facilities owned by several operators located in different states are not legally and practicably enforceable. The EPA is adopting these criteria in an attempt to reduce or eliminate such cases.

Comment: Commenter (0817-GPA) argues that the November 2021 Proposal's legal rationale for the change in definition is also problematic, relying largely on dicta from *National Mining Association v. EPA*, 59 F.3d 1351 (D.C. Cir. 1995). This case held only that the term "has the potential to emit considering controls," as used in 42 U.S.C. § 7412(a)(1), may include, as "controls," any effective state or local regulation or permit limitation and that EPA failed to justify its position that only "federally enforceable" controls are authorized under the statute. It is true that EPA was not "obliged to take into account controls that are only chimeras and do not really restrain an operator from emitting pollution," 59 F.3d at 1362, but this only explains the court's holding "that Congress intended the term to stand for effective controls" without regard to whether they were federal, state, or local. *Id.* The commenter adds that there is a wide expanse of options between ineffective "chimeras" and "effective controls," yet they contend that the EPA asserts that *National Mining Association* dictates the use of a very narrow band of specific permit terms in order to be "effective," which we submit is an incorrect reading of the court's ruling.

In fact, the commenter (0817-GPA) contends that nothing in *National Mining Association* discusses, much less compels, the November 2021 Proposal's revisions to the definition of "legally and practicably enforceable." There, EPA argued that "[g]eneral, as opposed to source-specific, permits can also be issued under a [federally enforceable state operating permit program], or under a state general permitting program similarly approved for inclusion within the [state implementation plan (SIP)]. And a state can impose constraints by general prohibitory or exclusionary rules, so long as they are included within its SIP. Finally, the SIP could be amended to reflect special source-specific limitations." 59 F.3d at 1363. The court rejected EPA's argument that tools such as general permits or permits by rule had to be federally enforceable. "What EPA has not explained is" its "refusal to credit controls imposed by a state or locality even if they are unquestionably effective. Under EPA's regime, the commenter notes that even a state program of unassailable effectiveness would not qualify in computing a source's capacity to emit unless it had been submitted not only for EPA approval, but also for inclusion in



the SIP.” Id. at 1364. But more importantly, the commenter states that the November 2021 Proposal now seems to reject EPA’s own position in that case, which endorsed the use of general permits and permits by rule. The commenter suggests that the November 2021 Proposal appears to preclude any form of general permit or permit by rule, contrary to what it argued in *National Mining Association*, not because they are voluntary and unenforceable, but because they lack the stringent and specific terms EPA has now decided to propose, once it provides regulatory text. The commenter asserts that EPA neither acknowledges nor explains this change in position.

To conclude, the commenter (0817-GPA) provides that they strongly oppose incorporating EPA’s new proposed definition of “legally and practicably enforceable” into a future NSPS OOOOb regulation. However, if EPA nonetheless determines to propose the new definition despite the numerous legal deficiencies, the commenter recommends that EPA provide appropriate flexibility to implement any new requirements. When sources fall within NSPS OOOOb requirements, owners and operators will be required to work with permitting authorities to establish new permit limitations, monitoring requirements, and recordkeeping obligations. Reopening permits for review and revision would take a significant amount of time, especially in states with a large number of upstream and midstream operations, such as North Dakota, New Mexico, Oklahoma, Pennsylvania, and Texas. The time required to implement these new permit terms will depend upon the resources and priorities of the permitting authorities, not the regulated midstream companies. Further, state and local permitting authorities may opt for existing permits to expire before implementing new terms. The commenter states that this could take several years. Thus, if EPA adopts its new definition of “legally and practicably enforceable,” the commenter suggests that EPA require compliance only upon the issuance of a new or revised permit from the permitting authority instead of establishing an arbitrary time limit for compliance. Under such a scenario, the commenter asserts that midstream companies should not be unfairly penalized for a permitting authority’s delay in updating permit terms.

Response I-9-31: The EPA disagrees with the statement made by the commenter that “What EPA has not explained is” its “refusal to credit controls imposed by a state or locality even if they are unquestionably effective.” The EPA does not agree that a control can be unquestionably effective without site-specific data showing a control system is operating within the parameters that show with actual data that it complies with a legally and practicably enforceable limit. The EPA does not reject the use of permits by rule or general permits to meet legally and practicably enforceable limits. Rather EPA is putting into regulatory text the requirements that EPA requires to ensure compliance. The legally and practicably enforceable specifications provided by this rule are specific to oil and gas storage vessels. Nothing in this rule prohibits permits by rule or general permits from providing legally and practicably enforceable requirements that a source can take into account when calculating its potential emissions, provided those LPE requirements meet the specifications provided by the rule.

#### **9.2.7 Potential to Emit**

Comment: Commenter (0803-Ohio Oil and Gas Association (OOGA)) states that EPA should not require sites to use the uncontrolled PTE calculation for storage vessels in the site-level baseline estimate to account for times when these vessels are not operating as designed (see 86 FR 63171). The commenter submits that normal operations should be assumed for purposes of

the baseline estimate, because consideration of abnormal operations will result in overestimating emissions and, thus, increased control costs with little environmental benefit. The commenter states that EPA has recognized that legally and practicably enforceable emissions limits and control requirements may be accounted for as it relates to storage vessel affected facilities and that requiring the use of assumed uncontrolled PTE for a particular source for purposes of one aspect of the proposed rule, but account for controlled emissions (which are legally and practically enforceable) in another aspect of the proposed rule would be perplexing to say the least.

In response to EPA's request for comment on whether the rule should use "uncontrolled PTE" to determine storage tank applicability, commenter (0793-PBPA), states that it should not do so for three reasons: (1) the impact to upstream sources would increase exponentially, both in terms of increased storage tank applicability and costs; (2) the impact on longstanding applicability triggers in federal and state air programs that account for and establish via permit "legally and practicably enforceable limit[s]" would increase; (3) because state NSR rules and permits address storage tanks, the existence of "large emission events" upon which EPA bases its request for comment can and should be addressed through NSR enforcement and not NSPS applicability.

Commenter (0844-EDF *et al.*) states that for EPA's storage vessel requirements to work as intended, it is critical that the PTE be calculated as accurately as possible and that EPA should consider defining storage vessels as affected facilities based on actual uncontrolled emissions, rather than defining a vessel as an affected facility based on potential to emit after a "legally and practicably enforceable limit" is taken into account. The commenter points out that there is a significant difference between actual uncontrolled emissions and EPA's PTE calculation; a tank with uncontrolled actual emissions of 120 tpy VOC, subject to a "legally and practicably enforceable limit" requiring 95 percent control of emissions, would have a PTE of 6 tpy VOC. However, the commenter states that controls frequently fail, and it is well established that storage vessels are often the source of large emission events due to open thief hatches, deterioration of the vessel, failure of control equipment, and many other reasons. The commenter recommends that EPA consider adopting Colorado's approach, which relies on actual uncontrolled emissions, rather than PTE.

Commenter (0817-GPA) states that EPA should make accommodations in its proposed EG OOOOc for those storage tanks that are already equipped with legally and practicably enforceable VOC controls, as those storage tanks are already required to reduce methane emissions, as a co-benefit to enforceable VOC reduction requirements. The commenter recommends that any estimate of methane emissions from these sources include the controls already imposed and that absent existing controls, EPA allow sources to take an enforceable limit to keep methane emissions below the 20 tpy threshold in lieu of satisfying any other existing source requirements.

For new sources, the commenter (0817-GPA) recommends that EPA establish only a VOC limit for storage vessels, to simplify rule compliance and state permitting actions for these facilities. The commenter cites to section 6.5.1 of the November 2021 Proposal Technical Support Document (TSD) which states that "the inclusion of a potential methane emissions limit is expected to have very limited impacts for new sources. Based on the E&P TANKS modeling

runs, only 9 of 103 storage vessels were projected to have methane emissions greater the VOC emissions.” The commenter states that they expect most storage vessels in the gathering and boosting (G&B) sector will have higher VOC emissions than methane emissions and based on this data from EPA, and since VOCs and methane are co-pollutants, they recommend that EPA should establish only a VOC limit for storage vessels.

Response I-9-32: See discussion in section IV.J.1.b of the December 2022 Supplemental Proposal regarding EPA’s rationale for including a potential for methane emissions in storage vessel applicability for new sources.<sup>33</sup>

In the November 2021 Proposal, EPA requested comment on whether facilities should use uncontrolled PTE calculations for their storage vessels in their site-level baseline estimates for determining the frequency of monitoring of fugitive emissions components at well sites, not for determining storage vessel applicability. EPA is not finalizing a site-level baseline emissions threshold for fugitives monitoring. See section IV.A.1.a.ii of the December 2022 Supplemental Proposal for discussion and responses to comments regarding site-level baseline emissions.<sup>34</sup>

### ***9.2.8 Determination of Potential Emissions***

Comment: Commenter (0598-CER) recommends that EPA develop a calculator for operators to use for calculating emissions from storage vessels. The commenter explains that they have been using the E&P TANKS program for the past several years to estimate emissions from storage vessels and recommends that EPA use the E&P TANKS program as a foundation to develop a web-based calculator, including methane emissions, for estimating emissions from storage facilities. The commenter further recommends that the calculator should be available no later than the date that operators are required to begin compliance with the revised regulation. The commenter explains that a web-based calculator is preferred because it will be easily accessible for operators, new software does not need to be installed on company managed computers, and EPA would be able to easily update the calculator to add new features.

Commenter (0599-MSC) states that current NSPS OOOOa requires that potential VOC emissions must be calculated using a generally accepted model or calculation methodology. The commenter requests that EPA confirm that potential methane emissions also shall be calculated using a generally accepted model or calculation methodology.

Response I-9-33: See discussion in section IV.J.1.b of the December 2022 Supplemental Proposal regarding “generally accepted” models or calculation methodologies for estimating storage vessel methane and VOC emissions.<sup>35</sup>

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<sup>33</sup> 87 FR 74800-74801 (December 6, 2022).

<sup>34</sup> 87 FR 74724-74725 (December 6, 2022).

<sup>35</sup> 87 FR 74801 (December 6, 2022).

### **9.2.9 State Program Alternatives**

Comment: Commenter (0831-AXPC) recommends that EPA continue its allowance of state program alternatives for the regulation of storage vessels or tank batteries to reduce what would otherwise be duplicative control, recordkeeping, and reporting requirements.

Response I-9-34: The final NSPS OOOOb and EG OOOOc continue to allow owners/operators to take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a federal, state, local, or Tribal authority.

### **9.2.10 Modification of Storage Vessel Affected Facility**

Comment: Several commenters (0820-Pioneer, 0911-North Dakota Petroleum Council (NDPC), 0938-TXOGA, 0831-AXPC, 0808-API, 0817-GPA) suggest that the November 2021 proposed definition of what constitutes a modification of a tank battery is inconsistent with the definition of modification with CAA 111 (codified at 40 CFR §60.14), which generally is defined as “any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies.”

Commenter (0911-NDPC) disagrees with the November 2021 proposed changes to the definition of modification with respect to storage vessel because EPA has not demonstrated the necessity of this change nor how its implementation will benefit the environment. The commenter further states that the proposed activities are not a “physical change in, or change in the method of operation of, a stationary source.” See 42 U.S.C. § 7411(a)(3). The commenter (0911-NDPC) provides by way of example, that as currently proposed, this could include the relocation or replacement of a storage vessel. The commenter recommends that the definition of modification with respect to storage vessels remain unchanged to remain consistent with the definition of “modification” under the CAA.

Commenter (0938-TXOGA) states that the November 2021 proposed activities which trigger modification in the rule are inconsistent with the statutory definition. The commenter provides the CAA definition of modification<sup>36</sup> which states, “[t]he term ‘modification’ means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted” and points out that in the November 2021 Proposal, EPA used “shorthand” language that refers to “change in operation,” and does not include the statutorily-referenced “change in *method* of operation” (emphasis added). The commenter states that they expect that when EPA provides regulatory language (to create a proposal) for comment, that EPA intends to use the statutory language, as it has in 40 CFR part 60 previously, and that the references in this notice to “operational change” are merely for convenience. The commenter explains that the “method of operation” language is important, given that EPA proposes that a

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<sup>36</sup> 42 U.S.C. § 7411(a)(4).

modification occurs “when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions.”<sup>37</sup>

Commenter (0938-TXOGA) goes on to provide comment on specific aspects of the November 2021 proposed physical changes or changes in what the commenter believes EPA means to be changes in the method of operation. The commenter states that the first two - the addition of a storage vessel to an existing tank battery and the replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases (as opposed to the replacement of a tank that does not increase aggregate storage capacity, which should not constitute a modification)<sup>38</sup> seem typical of physical changes to the tank battery, in that they involve both construction and an increase in capacity. The commenter states that the last activity which is a modification trigger; *i.e.*, the receipt of additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery), is not a physical change and it does not constitute a change in the method of operation of the vessel or battery.

According to the commenter (0938-TXOGA), EPA is making two potential errors in their analysis. First, the commenter states that a tank is a tank and if there is not a change to the tank itself (*e.g.*, no accommodation that needs to be made to accept the increased throughput), then the “affected facility” – *i.e.*, the tank/battery – has not been physically changed. Second, the commenter states that the method of operation of a tank is to receive, store, and dispense its contents and that receiving more or less, short of the actual capacity of the tank, cannot logically be a change in its method of operation. The commenter states that the NSPS general provisions exclude from the definition of “modification” “an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.”<sup>39</sup> Third, the commenter states that there appears to be an assumption by EPA that an “increase” in throughput necessarily meets the requirement for an increase in potential emissions and it is not necessarily going to hold true across the board and should not be presumed. The commenter states that they think that EPA may be recognizing this in the statement that the rule would require the owner or operator to “recalculate the potential VOC emissions” in such instances, but because there is no proposed regulatory text, the commenter is unable to ascertain EPA’s intent and for this reason, among others, cannot meaningfully comment on the issue at this time. Later in the preamble,<sup>40</sup> the commenter explains, EPA states that a “single storage vessel or tank battery *is modified* when any of the following physical or operational changes are made” and then lists these same activities (*i.e.*, addition of a tank to an existing tank battery, replacement of a tank that increases battery capacity, increasing throughput to an existing tank). The commenter references EPA’s reasoning from the preamble<sup>41</sup> that for the first two activities, “the increased storage capacity will lead to higher breathing losses and thereby increase the VOC emissions” and with respect to the throughput criterion, EPA states that it will “increase the volumetric

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<sup>37</sup> See 86 FR 63178. The commenter (0938-TXOGA) interprets EPA’s shorthand references to physical or operational change as meaning “physical change, or change in the method of operation” and does not ascribe legal significance to the “operational change” on its own. 40 C.F.R. § 60.14.

<sup>38</sup> The commenter (0938-TXOGA) emphasizes that the relocation of an affected facility does not constitute construction of a facility under 40 C.F.R. § 60.14.

<sup>39</sup> 40 C.F.R. §60.14(e)(2).

<sup>40</sup> 86 FR 63198.

<sup>41</sup> 86 FR 63199.

throughput of the tank battery relative to the throughput prior to storage of the additional fluid.” The commenter counters that this rationale does not consider that an increase in throughput does not necessarily lead to an increase in emissions, depending on the capacity of the existing storage vessel, and that it is not appropriate to bypass the emissions increase step in the modification analysis which is required by the statutory modification definition.

Commenter (0938-TXOGA) references the Background Technical Support Document<sup>42</sup> and EPA’s description of storage vessel emissions therein, where EPA describes that throughput for storage vessels may vary for a number of operational reasons, which leads to variations in the type and nature of emissions. The commenter states that such variations are not physical changes or changes in the method of operation, rather, they reflect the normal operation of the existing tanks as the production from a particular well or wells that are utilizing the tank vary and that such variations occur without any actual change to the tank itself. The commenter states that the parenthetical in the preamble “from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery”<sup>43</sup> is confusing and inaccurate because it reaches beyond the defined affected facility, and, even if it were appropriate (which it is not), the “such as” language is unclear as to what EPA would consider to be a physical or operational change beyond those two specific examples. The commenter recommends that to the extent that EPA seeks to identify specific activities that constitute changes for which a source would evaluate if an emissions increase will occur, EPA should list those actions specifically (and should limit it to the affected facility in question). Finally, for sources that have restricted potential emissions from the vessel and/or battery to below 6 tpy, the commenter states that the requirement to “recalculate” VOC PTE is duplicative. The commenter explains, that in practice, to ensure that they do not trigger the requirements of the rule, many operators accept limits on their PTE and in such instances, no recalculation would be needed, as a modification could not occur since it requires both a change and an increase in potential emissions. The commenter requests that EPA clarify that this is not the intended result.

Commenter (0831-AXPC) asserts that the definition for what constitutes a modification of a tank battery is inconsistent with the definition of modification within the CAA 111 (40 CFR 60.14) and provides by way of example, that contrary to EPA’s November 2021 Proposal that a single storage vessel or a tank battery is modified when it “receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from activities such as refracturing a well or adding a new well that sends these liquids to the tank battery),” the storage vessel or tank battery is neither physically changed nor operationally changed as the change occurred at a different affected facility. The commenter states that the example does not speak to a demonstration that the additional throughput resulted in an increase in the emission rate of the storage tank or tank battery. The commenter explains that practically speaking, operators would not be able to compliantly send additional throughput to a vessel or battery that would cause the facility to exceed its permitted emissions. The commenter adds that it is also important to note there will be circumstances that an operator may have need to replace a storage vessel, which should not trigger modification unless it increases the potential to emit at the facility. In

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<sup>42</sup> “Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 C.F.R. Part 60, subpart OOOOb (NSPS), 40 C.F.R. Part 60, subpart OOOOc (EG),” at 6-1 (Oct. 2021), Docket ID No. EPA-HQ-OAR-2021-0317-0166 (Background Technical Support Document).

<sup>43</sup> 86 FR 63198.

summary, the commenter recommends that EPA adhere to the statutory definition for modification as it relates to a single storage vessel or a tank battery.

Commenter (0808-API) states the November 2021 proposed definitions have two flaws and are not consistent with the CAA because (1) they do not require a physical or operational change at the given affected facility; and (2) they presume an emissions increase where such an increase often would not occur. Regarding the perceived first flaw, the commenter explains that according to EPA's November 2021 Proposal, a physical change or change in the method of operation is deemed to occur at a given centralized production facility (CPF) or tank/tank battery, even though no physical or operational change has occurred at that CPF or tank/tank battery. Under these definitions, the commenter states that the relevant physical or operational change occurs at a different affected facility, which does not satisfy the statutory requirement that the modification of a given affected facility must entail a physical change or change in the method of operation at that same facility. The commenter explains the second flaw is that EPA has not demonstrated that these activities necessarily result in an emissions increase at the given CPF **or tank/tank battery** [emphasis added]. By way of example, the commenter provides that the fact that an upstream well is modified does not necessarily mean that a downstream CPF or tank/tank battery would have an actual emissions increase. More importantly, the commenter states, there is even less likelihood that the downstream operations would have a regulatory emissions increase, given that the 40 CFR part 60 definition of "modification" requires an increase in the short-term potential to emit of an affected facility. 40 CFR. 60.14(b).

Commenter (0820-Pioneer) recommends several revisions to the activities which trigger modification in the 2021 November Proposal:

- i. *Addition of a tank to an existing tank battery.* The commenter recommends that this modification trigger should be removed unless there is a corresponding increase in production at the tank battery. The commenter explains that adding a tank to an existing battery, which is already controlled under existing rules/regulations, does not increase emissions. The commenter also stated that their tank storage systems are all manifolded, such that the addition of one or more tanks, without a corresponding increase in production, would not increase emissions.
- ii. *Replacement of a tank that increases battery capacity.* Commenter recommends that this modification trigger should be removed for the same reasons the commenter provides above. The commenter further states that an increase in capacity does not equal an increase in emissions and, therefore, should not be considered a modification under any rule.
- iii. *Increasing throughput to an existing tank.* The commenter recommends that EPA define "increasing throughput" in accordance with how storage tanks are managed through the state permitting process. The commenter explains that storage vessels typically are permitted at the maximum physical production throughput based on equipment at the site. The commenter explains that this is done as a safety factor, but the storage vessel emissions never actually operate at the maximum PTE. The commenter

suggests that EPA include language that specifies an increase in throughput above current permitted PTE would be considered a modification.

Commenter (0817-GPA) suggests the following change to the definition of “modification” (underlined text represents suggested additions, and cross-outs represent suggested deletions):

Physical or operational changes would be defined to include: (1) The addition of a storage vessel to an existing tank battery; or (2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases; and/or ~~(3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput.~~

The commenter (0817-GPA) explains that the receipt of additional product to an existing storage vessel should not be defined as a modification as 40 CFR 60.14(e)(2) explicitly excludes from the definition of “modification” any “increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.” Further, the commenter believes the proposed definition disregards whether the addition of product would actually result in emissions increases from the storage vessel.

Although the commenter (0817-GPA) stresses that EPA must require both a physical change to the storage vessel and an emissions increase, as currently required by 40 CFR 60.14(a), if EPA is intent on changing the definition of “modification” to include a reference to throughput, the commenter recommends that EPA specify any increase in throughput to exceed existing permitted limits, instead of defining a “modification” as any increase in throughput. Particularly with respect to the midstream sector, the commenter asks EPA to understand that liquid throughput volumes at midstream facilities are not impacted significantly by the addition or refracturing of a well at an upstream site; these are not physical or operational changes at midstream facilities, but somewhere else. The commenter explains that for midstream facilities, an upstream facility adding or refracturing a well simply means receiving a relatively minor volume of additional product, which is part of routine operations and is evaluated in potential to emit calculations during permitting activities and that the receipt of additional product is not a change to the regulated facility itself and the routine changes in product volume are already accounted for by permitting agencies as part of the facility design.

Commenter (0814-IPAA *et al.*) states that EPA’s November 2021 Proposal for changing the modification threshold based on new production directed to a tank battery creates unnecessary complications based on poorly understand industry practices. The commenter explains that tank batteries are designed based on the initial production from a grouping of oil or natural gas well sites, but later will operate at a throughput well below their design rate. Because of this, the commenter explains it is common industry practice for wells to be redirected to different tank batteries at new or existing well sites to consolidate operations. The commenter states that at low production well sites, these redirected wells are frequently low production wells, but regardless will deplete further over time. The commenter references EPA’s statements that applying vapor capture to existing tanks is more costly and can confront structural challenges compared to new tanks. Further, the commenter references EPA’s determination that the cost effectiveness for regulating methane emissions from storage tanks differs from VOC when setting the emissions



threshold at 20 tpy. The commenter believes that EPA's new definition of modification triggers a convoluted decision process that can drive expensive tank reconstruction expenditures for temporal changes in emissions. By way of example, the commenter references EPA's proposed EG OOOOc which would not require vapor capture from an existing tank if its methane emissions are less than 20 tpy. Further, the commenter cites to E&P TANK documentation that shows that there are circumstances where a condensate or crude oil tank with less than 20 tpy of methane emissions could have VOC emissions exceeding 6 tons/year. The commenter states that EPA's revision to the definition of modification provides that the addition of production from any well new to a tank battery will be considered a modification because it alters the tank battery emissions even though the emissions may be well below the design capacity of the tank battery and even though the change may be temporal when the new well's production declines. Further, the commenter explains, even though the emissions increase might not cause the tank to exceed 20 tpy of methane, if the tank was already emitting more than 6 tpy of VOC, vapor capture would be required (and even though emissions could fall below 6 tpy of VOC when the production decline). Additional considerations, the commenter provides, is that an operator with a battery already controlled well over 95 percent under a state permit (but that doesn't meet the legally and practically enforceable requirements), would become a NSPS OOOOb tank battery which will not result in any additional reduction in emissions and actual environmental benefit but will add regulatory burden. The commenter suggests that EPA did not anticipate this scenario, which increases regulatory burden without some environmental benefit.

The commenter (0814-IPAA *et al.*) believes that these cyclical emissions circumstances can drive capital costs for low production operations that result from minor increases in emissions (or no overall emissions increase if an existing well is being transferred from one tank battery to another) and can result in the perverse effect of keeping uncontrolled tank batteries in operation because the cost of retrofitting vapor capture on the "modified" tank battery is too costly. As an alternative, the commenter suggests that EPA should use intermediate control strategies that can provide cost effective emissions reductions, particularly for the universe of low production wells. The commenter provides the specific example that where a tank battery is modified because a well is newly added to it but where all of the wells feeding it are low production wells, a cost-effective action would be to require an audio, visual and olfactory (AVO) inspection of these tanks to assure that thief hatches are closed, and seals maintained until the tank battery emissions exceed 20 tpy of methane. The commenter believes that such an approach would be consistent with EPA's determination that tank battery emissions of 20 tpy of methane is the cost effectiveness threshold for vapor capture while achieving emissions reductions from thief hatches and seals that have been identified as a significant component of tank emissions.

Commenter (0777-Ascent) suggests that EPA include an exception from the definition of "modification" for a nominal increase in capacity. The commenter is concerned that the definitions of "modification" and "physical or operational change" as applied to tank batteries is overbroad and will capture de minimis changes at tank batteries that are not associated with an attempt to build out the capacity of the tank battery with a new tank or any increase in throughput of the tank battery. To accomplish this, the commenter recommends that EPA exclude tank replacements not associated with a throughput increase from the definition of "physical or operational change" for purposes of tank batteries. The commenter proposes that physical or operational changes would be defined to include: (1) The addition of a storage vessel

to an existing tank battery; ~~(2) replacement of a storage vessel such that the cumulative storage capacity of the existing tank battery increases;~~ and/or ~~(2)(3)~~ an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). The commenter notes that this definition would capture the addition of new tanks and increases in throughput and emissions, but it will not capture a change where, for example, an existing vessel is replaced with a slightly larger vessel where the owner or operator is not making the change to accommodate increased throughput. Owners and operators may need to replace a vessel and the available replacement options are slightly larger, though the increase in capacity is not the driver for the change, the commenter maintains. In those circumstances, the commenter states, the vessel replacement should not be considered a modification, or a physical or operational change, of the tank battery. The commenter requests that, if EPA continues to propose storage vessel applicability on a tank battery basis, EPA propose a definition of “physical or operational change” that includes the addition of a new storage vessel and the tank battery’s receipt of additional throughput, but does not make the replacement of an individual storage vessel with increased capacity, where there is no associated change in throughput, a change that could be considered a modification of the storage vessel affected facility.

Commenter (0739-Citation) states that EPA is proposing that a single storage vessel or tank battery is considered modified when an existing tank battery or single storage vessel receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery). The commenter adds that historically, an increase in production rate of an existing facility is not a modification if that increase can be accomplished without a capital expenditure on that facility. The commenter requests that EPA exempt storage vessels or tank batteries which are subject to a legally and practicably enforceable limit in an operating permit or other requirement established under a federal, state, local or Tribal authority from this modification definition.

Conversely, commenter (0844-EDF *et al.*) supports EPA’s November 2021 proposed definition of “modification” for storage vessels. The commenter states that adding a storage tank to a tank battery is a physical change to a storage vessel affected facility that results in an increase in emissions. The commenter contends that replacing a storage vessel with one that has a larger volumetric capacity is also a physical change that increases emissions and it is the commenter’s understanding that this frequently occurs at facilities that are space-constrained; rather than clear new land or space for a new storage vessel, operators who need increased storage capacity will choose a taller vessel that fits the same footprint as the one being replaced, thus increasing capacity without taking up more space. Finally, the commenter states that a tank battery that receives increased throughput that results from the refracturing or addition of a well increases its emissions beyond the projected emissions without that operational change. The commenter states that each of these three actions are modifications as defined by the CAA.<sup>44</sup> Additionally, the commenter recommends that an operator be required to reevaluate a storage vessel affected facility’s PTE after a modification has occurred; for example, replacement of a tank indicates that either there was something wrong with the older tank, or that there was a need for more

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<sup>44</sup> 42 U.S.C. 7411(a)(4).

capacity. Similarly, the commenter argues, the addition of a tank indicates a need for more capacity. In both instances, the commenter states, the facility is undergoing a physical change that inherently affects its emissions, hence the PTE for the source in question should be reevaluated, (as it should also be whenever increased throughput is set to occur). The commenter adds that even with the same controls, the replacement of a smaller storage vessel with a larger one, or the addition of a new vessel to a battery, can change the potential to emit and because there are applicability thresholds where a new storage vessel could be unregulated because its PTE is below 6 tpy, an operator should have to demonstrate that the modified facility's PTE is in the same category (affected vs. unaffected) as it was prior to the modification.

Response I-9-35: With regard to the general definition of modification of tank batteries, see discussion in section IV.J.1.b of the December 2022 Supplemental Proposal.<sup>45</sup>

EPA disagrees with commenters that the definition of modification of tank batteries is inconsistent with the definition of modification within the General Provisions at 40 CFR 60.14. The definition included in the final rule (section 60.5365b(e)(3)(ii)) includes both a physical/operational change and a resulting emissions increase, which is consistent with the General Provisions definition. The final rule defines modification of a tank battery occurring when any of the actions below result in the potential for VOC or methane emissions to meet or exceed either of the thresholds (6 tpy VOC or 20 tpy methane):

- (1) a storage vessel is added to an existing tank battery,
- (2) one or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases,
- (3) for tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, includes but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well), or
- (4) for tank batteries at compressor stations or onshore natural gas processing plants, an existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent determination of the potential for VOC or methane emissions.

An existing tank battery or single storage vessel will become subject to the NSPS if one of the actions in this definition of modification occur and the potential VOC or methane emissions are greater than or equal to the 6 tpy VOC/20 tpy methane emissions threshold. Commenters contend that the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well) does not require a physical or operational change at the given affected facility (i.e., the tank battery); and presumes an increase in emissions where such an increase often would not occur. The EPA disagrees with the commenter for the following reasons. As explained in the November 2021 preamble<sup>46</sup>, those

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<sup>45</sup> 87 FR 74801 (December 6, 2022).

<sup>46</sup> 86 FR 63199 (November 15, 2021).

actions (e.g., addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well) which result in the receipt of additional regulated fluids will increase the volumetric throughput of the tank battery relative to the throughput prior to storage of the additional fluid which constitutes an operational change. Further, this increase in volumetric throughput will result in an increase in working losses and potentially flashing losses from the tank battery which constitutes an increase in emissions. However, in order to determine if these actions result in applicability to the NSPS, the owner or operator must recalculate the potential for VOC and methane emissions using the methodologies at §60.6535b(e). In those instances where the potential to emit remains below 6 tpy VOC or 20 tpy methane, the NSPS will not apply; where these changes result in potential emissions at or above those thresholds, the NSPS applies.

Other commenters contend that since the emissions rate has not increased, a modification has not occurred. The EPA dismisses this out of hand, because of the inherent difference in sources that emit vastly different quantities of emissions when controlled with a control device that meets a control efficiency of 95 percent. The EPA continues to assert that actions described in the definition of modification result in emissions increase to the atmosphere, either through an increase in capacity or an increase in throughput. Those additional working, breathing or flashing losses result in an increase in emissions to atmosphere, even if controlled, unless the control efficiency is increased to mitigate those additional emissions. This comment also misses the point of having a 6 tpy threshold for affected facility status, to distinguish between those for which control is cost effective, and for those that control is not cost effective. The foundation of nearly all CAA rules is to ascribe controls appropriate to the potential for emissions. Regarding the comments related to capital expenditure, the EPA disagrees that a capital expenditure is requisite to the definition of modification. 40 CFR 60.14(f) allows EPA to set provisions specific to an applicable subpart, which we have done here. As other commenters have noted, the General Provisions at 40 CFR 60.14. defines a modification as both a physical or operational change and a resulting emissions increase to the atmosphere. The definition of modification reflects both of these elements, and need not include any reference with respect to capital expenditure.

## **9.3 BSER**

### ***9.3.1 General***

Comment: Commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) requests clarification whether the proposed GHG standards for 95 percent methane reduction for storage tanks (battery) with PTE  $\geq$ 20 tpy shown in Table 3 of the November 2021 Proposal are more stringent than the current 6 tpy VOC threshold for tank emission reductions.

Response I-9-36: The BSER for storage vessel affected facilities has not changed in stringency from the NSPS OOOO and NSPS OOOOa requirements to reduce VOC emissions by 95 percent. The stringency of the applicability, however, has changed in such a way as to consider

both the methane and VOC emissions from an entire tank battery, instead of each individual storage vessel.

Comment: Commenters (0781-NTAA, 0943-Sault EPD, 0391-KBIC, 0605-Muscogee (Creek) Nation, 0833-Ute EPD) request that EPA consider requiring higher control than 95 percent reduction in emissions where it is feasible.

Commenter (0756-Baker Hughes (BH)) states that EPA should consider raising the targeted VOC and methane minimum allowable control efficiency to 98 percent. The commenter explains that there are thief hatch technologies (*e.g.*, thief hatch elimination devices) in late-stage development that will eliminate the vent to atmosphere from thief hatches and therefore will achieve higher reductions in storage vessel emissions associated with thief hatches. The commenter states that this device would retrofit on to existing storage tanks and would replace thief hatches on new storage tanks and would eliminate virtually 100 percent of the emissions resulting from thief hatches, as it provides a pipe-away configuration to a vapor recovery system while still providing access to the tank contents for gaging and sampling purposes and has the added benefit of protecting the worker from being exposed to flammable atmosphere at the thief hatch port as well as toxic vapors from the storage tank head space.

Response I-9-37: Regarding the comment that EPA consider requiring higher control than 95 percent reduction in emissions where it is feasible, EPA discussed the results of the analysis which was used to establish emissions limits for storage vessels in section XII.B.1.e. of the November 2021 Proposal. The commenter did not dispute this analysis nor provide additional information for the EPA to consider.

EPA acknowledges the commenter's statements regarding thief hatch technologies and encourages owners and operators to utilize new technologies, such as those described by the commenter. However, the commenter did not provide enough information to allow EPA to evaluate the costs and feasibility of the use of these technologies for consideration in revisions to the BSER for storage vessel affected facilities at this time. Therefore, the BSER for storage vessel affected/designated facilities in the final rules is 95 percent reduction of VOC and methane emissions (for new sources) and 95 percent reduction of methane emissions (for existing sources).

Comment: Commenter (0786-Enerplus Resources (USA) Corporation (Enerplus)) describes other thief hatch improvements such as lock-down thief hatch systems. The commenter explains that while a traditional thief hatch designs provide three potential leak points per thief hatch (a total of 24 potential leak points for a typical eight storage vessel battery), lock-down thief hatch systems eliminate those potential leak points and replaces them with only three, significantly more reliable, pressure and vacuum relief points for the same eight storage vessel battery. The commenter explains that their new storage vessels are rated to 32 ounces of pressure as compared to a typical API 12f storage vessel rated to 16 ounces and that this difference provides cushion for pressure swings and pressure relief is pallet-weighted to relieve at a higher pressure without fluttering open prior to the relief setpoint. The commenter requests reduced inspection

frequencies for facilities engineered to eliminate and prevent leaks to encourage technological innovation across the industry.

Response I-9-38: See Response I-9-37.

Comment: Commenter (0817-GPA) suggests that EPA should consider existing enforceable controls for storage vessels. The commenter states that they do not oppose a threshold of 20 tpy for methane emissions from existing storage vessels, but do not support a lower threshold. Further, the commenter states that EPA should make accommodations in its proposed guidelines for those storage tanks that are already equipped with legally and practicably enforceable VOC controls as those storage tanks are already required to reduce methane emissions as a co-benefit to enforceable VOC reduction requirements. The commenter recommends that any estimate of methane emissions from these sources include the controls already imposed and that absent existing controls, and that EPA allow sources to take an enforceable limit to keep methane emissions below the 20 tpy threshold in lieu of satisfying any other existing source requirements. The commenter states that doing so could alleviate some of the logistical difficulties on state agencies, as methane emission limits are not currently included in most permits. The commenter is concerned that without considering existing controls, state and local permitting agencies would be required to re-open thousands of existing permits in order to create new methane emission limits.

Response I-9-39: EPA agrees with the commenter that controls of VOC are equally effective for methane, and that sources that are controlling VOC emissions will be controlling methane emissions to the same degree. Addressing the concern of re-opening existing permits, provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source designated facilities under OOOOc, and are not retroactively applicable to OOOO or OOOOa sources. As states develop their plans under OOOOc EG, the requirements as applicable to designated sources, multiple options exist to implement the criteria that EPA is promulgating to define legally and practicably enforceable emission limitations.

Comment: Commenter (0446-Artex Oil Company (Artex)) requests that EPA establish an explicit exemption for existing conventional oil and gas wells, as the cost of applying the November 2021 proposed emissions guidelines for control of emissions from storage vessels will force many owners and operators to either shut-in or, in some cases, potentially abandon these assets. The commenter believes that the resulting loss of these valuable natural resources runs counter to the directive of the Ohio Department of Natural Resources (ODNR) to preserve the responsible use of existing natural resources in their states of jurisdiction.<sup>47</sup>

Response I-9-40: The commenter has not provided any information on the potential for VOC or methane emissions from storage vessels associated with conventional wells. Therefore, EPA is unable to evaluate if a categorical exemption for conventional wells is appropriate.

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<sup>47</sup> See, for example, Ohio Revised Code [ORC] 1509.20 which requires “every reasonable precaution in accordance with the most approved methods of operation to stop and prevent waste of oil or gas, or both.”

Comment: Commenter (0814-IPAA *et al.*) recommends that EPA develop emissions management strategies that do not require vapor capture for lower emissions tank batteries. By way of example, the commenter states that data collected by GSI Environmental, Inc, and even environmental groups, show that significant emissions sources at tank batteries are open thief hatches and deteriorated seals around tank openings, which can be addressed through routine operational and maintenance programs.

Response I-9-41: See discussion in section IV.A.1.a.ii of the December 2022 Supplemental Proposal.<sup>48</sup>

Comment: Commenter (0911-NDPC) requests that EPA clarify what type of storage vessels are covered under the November 2021 Proposal, as the BSER analysis appears to only cover fixed roof tanks.

Response I-9-42: The final rule for NSPS OOOOb defines storage vessel at 60.5430b as follows:

*Storage vessel* means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

- Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.
- Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.
- Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

This same definition is also included in the final EG OOOOc, with reference to specific sections in the model rule language for EG OOOOc replacing the NSPS OOOOb references. This definition is consistent with the definition in NSPS OOOOa.

The final rules apply to all storage vessels, as defined in the rules, that exceed the applicability threshold and is not limited to fixed roof tanks. Owners/operators may use a floating roof to meet

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<sup>48</sup> 87 FR 74730 (December 6, 2022).

the required standards as specified in 40 CFR 60.5395b(b)(2) (i.e., where the storage vessel affected facilities does not have flashing emissions and is not located at a well site or centralized production facility).

### ***9.3.2 Costs of Control are Underestimated***

Comment: Commenters (1341-PGCC *et al.*) state that the November 2021 Proposal is unreasonable and must not be applied to their members.<sup>49</sup> The commenters explain that the storage tanks used by their members<sup>50</sup> are relatively small and often not designed to hold fluids at pressure and that EPA's model tank batteries are materially and significantly different from the tanks used by their members. The commenters state that EPA's cost-effectiveness calculations are therefore flawed and substantially underestimate the costs that would be imposed on their members if they were required to take all the steps necessary to install and operate a flare, enclosed combustor, or VRU to control what are already exceedingly small amounts of emissions. Specifically, the commenters explain that requiring any type of emission control device for these tanks would require that they be modified, if possible, or likely replaced altogether to install the control devices that EPA proposes to require and that EPA's cost evaluation only analyzes the estimated cost for *controlling* emissions. *See* November 2021 Proposal TSD, §6.4.3.3 (evaluating only the cost of control systems). The commenters suggest that such costs would be exorbitant, especially for the many small businesses in their member Conventional Groups and recommend that EPA gather information on the number and types of tanks employed by conventional oil and gas operators, and analyze this information, to determine BSER for these tanks.

Commenter (0808-API) requests additional consideration regarding costs of control for certain scenarios. The commenter states that as oil production declines, operators may need to replace the original storage vessel or tank battery combustion device with a smaller capacity device. The commenter states that applying the same threshold as a single storage vessel to a tank battery means that a control device will be required for a longer duration and that this longer control duration (and potential additional costs for a smaller replacement control device) were not considered in EPA's cost analysis.

Commenter (0793-PBPA) contends that the requirement to install VRUs will have an excessive impact on small business operators, which they state EPA has not considered. The commenter goes on to explain that each oil and gas facility is operated differently depending on, among other things, the location (basin), the type of product produced, the amount of product produced and stored, the age of the field where the product originates, various treatment options at the production site, the age of the production and storage equipment, and the available transportation infrastructure. The commenter states that all of these considerations play a role in determining the amount of emissions associated with oil and gas production and storage operations; yet EPA's November 2021 Proposal effectively treats all storage tanks the same. In particular, the commenter explains that section 111 of the CAA requires that EPA consider a number of factors,

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<sup>49</sup> 1341- Pennsylvania Grade Crude Oil Coalition, Pennsylvania Independent Petroleum Producers, Pennsylvania Independent Oil & Gas Association, and Independent Oil & Gas Association of New York identify as the "Conventional Groups."

<sup>50</sup> The "Conventional Groups."



including cost, in determining “the best system of emission reduction . . . adequately demonstrated”<sup>18</sup> but that when evaluating the cost of emission controls per ton of emission reduction, EPA evaluated potential emission reductions and associated control costs on an industry-wide basis and did not adequately considered the impacts to those smaller operators, whose emissions may be so small that the requirement to install VRUs is cost prohibitive or those operators who lack the operational economy of scale and in-house environmental, health, and safety personnel to implement the required emission controls in a cost-effective manner. The commenter also cites to the Boston University’s Institute for Sustainable Energy, which states that “in practice VRUs are only practical at larger facilities.”<sup>19</sup>

Regarding existing sources, the commenter (0793-PBPA) explains that as wells and fields age, production decreases and storage tanks that were full when a well was new and highly productive may be operated at significantly less than capacity as oil and gas fields become depleted, but operational costs associated with running and maintaining emission control devices do not. The commenter states that section 111(d) of the CAA requires that EPA allow states, when applying the EG, to take into consideration, “among other factors,” the remaining useful life of the existing sources<sup>51</sup> but that EPA’s proposed EG OOOOc does not account for remaining useful life or “other factors” (*e.g.*, unreasonable cost of control resulting from plant age, location (basin), or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to classes of facilities that make application of a less stringent standard or final compliance time significantly more reasonable).<sup>52</sup>

Specific to costs for a VRU, the commenter (0793-PBPA) states that EPA estimated capital costs for a VRU (sized for a source with potential VOC emissions of 6 tpy) to be approximately \$32,000 and the estimated annualized costs are estimated at approximately \$24,000/yr, but that these numbers significantly understates the cost of a VRU on a tank because of the potential for oxygen to enter the pipeline through the VRU’s series of pipe connections and fittings, which presents a prominent safety issue and can result in extensive down time, resulting in annual operating expenses that are much higher due to the costs associated with preventing oxygen contamination. The commenter states that since 2012 Texas has added approximately 15,750 wells per year, resulting in 142,000 wells becoming subject to NSPS OOOO and that in general, each storage tank supports four wells; thus as many as 35,500 facilities will need to add VRUs and at a cost of \$32,000 per VRU, the November 2021 Proposal would cost \$1.4 billion in Texas alone. The commenter states that this is not an incidental cost to propose without quantifying the emission reductions from this requirement and that while some operators will already have VRU-type equipment, EPA has not estimated the impact of this rule nor the proportional cost benefit.

Commenter (0808-API) generally supports EPA’s November 2021 Proposal for existing storage tank batteries under EG OOOOc but provides one additional consideration for existing storage vessels or tank batteries. The commenter explains that there is additional cost for control at sites in dry gas plays with produced water storage vessels or tank batteries only which was not included in EPA’s cost analysis - some of the produced water storage vessels are fiberglass tanks and would have to be replaced with steel tanks to support the installation of a closed vent system

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<sup>51</sup> 42 U.S.C. §7411(d)(1).

<sup>52</sup> See, *e.g.*, 40 C.F.R. §60.24(f).

and control device due to backpressure. The commenter suggests that if the capital costs to replace a storage vessel(s) are \$20,000 or more this would result in a cost effectiveness of over \$1,900 per ton of methane reduced for a combustion control device, using EPA's own cost analysis, and this was not included.

Commenter (0817-GPA) states that while EPA acknowledges that it will be more costly to install a combustor control device or VRU at an existing facility than at a new facility, the estimated 30 percent increase in the capital cost at existing facilities to account for the additional costs is not supported. The commenter references EPA's costs for a flare system ranging from \$23,806 to \$43,598. The commenter believes the additional cost required to install a tank control system at an existing facility will be higher than EPA's estimate, due to the additional engineering design that would be required to add an ignition source to an existing facility, the additional construction costs required for an extended flow line to locate the flare away from other ignition sources, such as compressor engines that would be present at most sites, and the additional costs needed to upgrade tanks to prepare for a closed vent system. Instead of a 30 percent factor, the commenter suggests that EPA assume 50 percent for the capital expense needed to retrofit an existing gathering and boosting facility. Based on this change and since the gas recovered is not owned by the gathering and boosting facility, the commenter provides suggested revisions to Tables 6-13 ("Thermal Combustion Control System Costs for Existing Tank Batteries") and 6-14 ("Vapor Recovery Control System Costs for Existing Tank Batteries") of the November 2021 Proposal TSD in their comment letter.

The commenter (0817-GPA) also suggests that EPA underestimated the cost to install a flare for low emission tanks. The commenter explains that because gathering and boosting facilities will not own the natural gas that flows through the facilities, they will have limited economic benefits associated with installing a VRU system on a low emission storage vessel battery. The commenter recommends that EPA update Table 6-15 ("Average Control System Costs for Model Control Systems for New Tank Batteries") and 6-17 ("Average Control System Costs for Model Control Systems for Existing Tank Batteries") of the November 2021 Proposal TSD to reflect that facilities will install flares instead of VRUs up through model control system number 5 (i.e., EPA should discount the capital costs for lower emitting tank batteries with the assumption that 50 percent of the facilities will install VRU systems). The commenter included a revised Table 6-15 and Table 6-17 from what EPA includes in the November 2021 Proposal TSD in their comment letter. The commenter also provided revisions to Table 6-17 in their comment letter, to reflect prior comments that the capital cost to install a control device will be 50 percent higher than at a new facility, which is an increase from the 30 percent adjustment included by EPA.

The commenter (0817-GPA) provides a table ("Cost Effectiveness for Existing Sources") in their comment letter that summarizes the impacts that adjustments for control device selection and additional capital costs for existing sources will have on cost effectiveness. To summarize, the commenter states that in general, the cost effectiveness is affected more for the lower emission tanks, since the flare installation will be an increase in capital cost and may affect the point where methane emission control alone would be considered cost effective.

Response I-9-43: EPA discussed the results of the analysis which was used to establish emissions limits for storage vessels in section XII.B.1 of the November 2021 Proposal.

See discussion in section IV.H.2 of the December 2022 Supplemental Proposal where EPA evaluated the costs associated with requiring 98 percent reduction of methane and VOC emissions from storage vessels in order to compare the cost-effectiveness for this option against the costs associated with requiring 95 percent reduction.

With regards to comments that indicated that storage tanks used by conventional wells are relatively small and often not designed to hold fluids at pressure, we take the comment to refer to existing storage vessels to which EG OOOOc would apply. The standards for an affected facility are cost effective relative to the emissions reductions obtained for existing facilities [See Response I-9-36]. The commenter also points out that existing facilities may require retrofitting to meet emission control requirements. The existing source requirements developed and implemented by states under EG OOOOc offer the opportunity for the commenter to work with their permit authorities to develop appropriate standards for existing sources. States are able to design standards that account for the remaining useful life of affected facilities, which may be less stringent than standards applicable to new sources. Generally, the standards developed for existing sources reflect retrofitting costs that do not apply to new sources.

With regards to the need to clarify what type of storage vessels are covered under the proposed rule, the EPA clarifies that production operators may not use floating roof tanks to meet the requirements of NSPS OOOOb, or EG OOOOc at well sites and centralized production facilities, because floating roofs are not designed to handle flash emissions. See 86 FR 63184. The NSPS Kb specifically exempts storage vessels with a design capacity less than or equal to 420,000 gallons (1,589.874 m<sup>3</sup>) used for petroleum or condensate stored, processed, or treated prior to custody transfer. These storage vessels that are exempt from NSPS Kb are only subject to NSPS OOOOb or EG OOOOc and must comply with the control requirements in NSPS OOOOb or EG OOOOc, as applicable. Storage vessels that do not have flashing emissions and that are not located at well sites or centralized production facilities may use floating roof controls following the provisions in NSPS Kb. We also note that NSPS OOOOb and EG OOOOc do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW. With regards to the need to clarify what type of storage vessels are covered under the proposed rule, the EPA clarifies that production operators may not use floating roof tanks to meet the requirements of OOOOb, or OOOOc EG at well sites and centralized production facilities, because floating roofs are not designed to handle flash emissions. See 86 FR 63184. We note that subpart Kb specifically exempts storage vessels with a design capacity less than or equal to 420,000 gallons (1,589.874 m<sup>3</sup>) used for petroleum or condensate stored, processed, or treated prior to custody transfer. These storage vessels that are exempt from subpart Kb are only subject to subpart OOOOb or OOOOc EG and must comply with the control requirements in subpart OOOOb or OOOOc EG, as applicable. Storage vessels that do not have flashing emissions and that are not located at well sites or centralized production facilities may use floating roof controls following the provisions in subpart Kb. We also note that Subparts OOOOb and OOOOc EG do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

With regards to comments that indicate that the EPA's high thresholds are based on unrealistically high estimates for the costs of emissions controls for tanks, compared to the emission control cost estimates provided by states, see Response I-9-7.

The change of applicability threshold to tanks and batteries reflects cost effective control down to 6 tpy. While operators are free to change their control systems to accommodate current conditions that may differ from the production conditions at startup (provided the control device reduces emissions by 95% or greater), the decision to change control equipment is at the discretion of the operator and not a function of applicability thresholds, which remain unchanged in the example provided by the commenter.

We specifically evaluated a wide range of potential emission rates from tank batteries. We agree that the capital and operating costs for the control device has economies of scale, which is why we established emission thresholds below which control is not required. We also note that we do not mandate the use of a VRU. We also estimated costs for flares and thermal oxidizers, and these control systems had similar costs to the VRU. We expect all operators, regardless of size, would have the expertise needed to operate a flare.

In response to commenters that indicated that they believed that VRU costs are underestimated, nearly all VRU include automation to prevent pulling a vacuum from the tank. Typically, they use a check-valve that prevents any flow from the storage vessel below a set operating pressure. When the valve is open, the VRU compressor/vacuum pump will start. The compressor (or vacuum pump) has a variable speed drive to pull more gas when the pressure in the line from the tanks increases. Thus, by selecting an appropriate VRU design, oxygen ingress can be minimized or eliminated. Additionally, we also note that we do not mandate the use of a VRU to control emissions from storage vessels; flares and thermal combustors can also be used to control emissions from storage vessels.

With regards to comments indicating that there is an additional cost for control at sites in dry gas plays with produced water storage vessels or tank batteries, we developed costs reflective of national averages. We understand that some facilities may experience costs that are less than those projected while other facilities may experience somewhat higher costs. For existing storage vessels or tank batteries, the storage vessel/tank battery would have to have emissions of 20 tpy methane or more to require controls. We expect that few produced water tanks at existing facilities would have emissions exceeding this threshold. Additionally, states may consider the remaining useful life of existing facilities in their EG. That said, in the very rare situation where a high-emitting produced water storage vessel, as described by the commenter, is at a facility with significant useful life, this would be an example where the costs to control are higher than the average costs we projected. We included retrofit costs for existing sources to vent the emissions from existing storage vessels to a control device. We determined that the costs we developed are reasonable for national standards, even if, in rare conditions, this may require upgrading the storage vessel itself. In response to the commenter that expresses that they believe that the additional cost required to install a tank control system at an existing facility will be higher than EPA's estimate, the EPA explains that, when estimating the cost of flare controls, we specifically included 200 feet of piping to transport the storage vessel vapors to a remote location. The flare costs also include engineering costs associated with sizing and locating the

flare (assumed to be 10% of equipment costs). We included the retrofit costs primarily to cover costs associated with upgrading the tanks to prepare for closed vent system, but some of these costs can also cover additional piping and engineering assessments. We consider that the cost assumptions we used for the new sources are reasonably conservative and that the 30% retrofit factor adequately covers additional expenses associated with applying these controls to existing sources.

In response to commenters that suggested that the EPA underestimated the cost to install a flare for low emission tanks, the EPA explains that the change of applicability threshold to tanks and batteries reflects cost effective control down to 6 tpy VOC and 20 tpy methane. We specifically evaluated a wide range of potential emission rates from tank batteries. We agree that the capital and operating costs for the control device has economies of scale, which is why we established emission thresholds below which control is not required.

### **9.3.3 Technical Considerations with BSER**

Comment: Commenters (1341-PGCC *et al.*) state that EPA also must consider the costs associated with significant infrastructure changes to install controls on these tanks and the fact that requiring continuous ignition could create unsafe conditions. The commenters state that installing and operating a VRU or flare would also require the installation and operation of technologies to prevent oxygen from entering the storage tank vent gas that would be collected and notes that EPA's "Standard Stock Vapor Recovery System for Storage Vessels" does not show an oxygen monitor and therefore, EPA's calculated control costs fail to consider costs associated with oxygen monitors. See the November 2021 Proposal TSD, Figure 6-1.

Commenter (0793-PBPA) states that the potential for oxygen to enter the pipeline through the VRU's series of pipe connections and fittings, presents a prominent safety issue and can result in extensive down time and also is likely to cause increased downstream emissions due to corrosion caused by the oxygen.

Commenters (1341-PGCC *et al.*) state that tanks used by their members are often located in rural, sometimes forested, areas that can be miles from available electrical sources, requiring the installation of electric line (because EPA notes a vapor recovery system used to control storage tank emissions "uses electricity to run the vapor recovery compressor." November 2021 Proposal TSD, 6.4.3.2). The commenters provide that even where electrical service is available, it is often available in single-phase and would be incapable of transmitting power over long distances. For intermittent flow and operational reasons, they state that tank emissions also would be insufficient to power a generator needed to operate a VRU, requiring manual operation of any vapor recovery unit and would result in additional costs (and emissions), which EPA did not consider.

Commenters (1341-PGCC *et al.*) posit that there is no plausible scenario where installing and operating a VRU to control storage tank emissions at well or tank sites operated by their members would be cost-effective. The commenters argue that the November 2021 Proposal, if finalized, will create more emissions at well sites owned by their members, because unlike tanks in the unconventional gas industry, which manage significantly large volumes of liquids at very

high pressures, flow into on-site tanks at conventional sites is intermittent. Because of the intermittent and low flows of liquids into the tanks, the commenters state that their members would be forced to pipe or store auxiliary fuel at the location of the flare or enclosed combustor because there is no fuel to allow for continuous operation of a flare or enclosed combustor. The commenters provide examples at conventional oil well sites where liquids are pumped at intervals ranging from once-per-day to once-per-week and conventional gas well sites where flow into tanks occurs only as necessary in the cycling of a rabbit or when sufficient fluid exists in the separator.

The commenters (1341-PGCC *et al.*) summarize their concerns by stating that EPA's model tank batteries are materially and significantly different from the tanks used by their members. According to the commenters, EPA's cost-effectiveness calculations are therefore flawed and substantially underestimate the costs that would be imposed on their members if they were required to take all the steps necessary to install and operate a flare, enclosed combustor, or VRU to control what are already exceedingly small amounts of emissions. They add that for all these reasons, EPA's November 2021 Proposal is unreasonable and must not be applied to their members.

Commenters (0808-API, 0831-AXPC) state that EPA should allow for an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel. The commenter explains that this type of exemption has been rationalized by state regulations for storage vessels and tank batteries, such as in Colorado, where there is an exemption from control requirements for tanks if use of a control device would be technically infeasible without supplemental fuel for pilot or other purposes.

Response I-9-44 We disagree with commenters that controlling emissions from storage vessels is technically infeasible when supplemental fuel is required. All flares or combustors will require supplemental fuel, either by natural gas or propane, for use for pilot gas and for sweep or purge gas. While we assumed most facilities would have natural gas available, propane can also be used. Perhaps because our control costs are higher than those used by Colorado (leading Colorado to select a much lower emissions threshold for storage vessels), the impact of using propane rather than natural gas does not significantly alter the cost-effectiveness of the emission controls at the applicability thresholds selected. Based on our analyses, we do not consider that it is technically infeasible to require control.

Comment: Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) recommends that EPA allow for thermal control of methane and VOC emissions from storage tanks, which are often vented to tanks routed to control devices with less than 100 percent destruction efficiency. The commenter believes that further consideration should be given to allow for control methodologies for this activity in line with typical oil and gas facilities, including thermal control using flares which typically represent less than 100 percent destruction efficiency.

Response I-9-45: We take the comment to be a concern for a requirement to capture and route associated gas to a sales line, use the recovered gas as an onsite fuel source, use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, reinject the

recovered gas into the well or inject the recovered gas into another well for enhanced oil recovery. This is not the case, as flaring as a means of control for storage vessels is not affected by the requirements in 60.5377b intended to reduce the flaring of associated gas from a separator.

#### ***9.3.4 Model Plant Emissions Estimates***

Comment: Commenter (0814-IPAA *et al.*) questions EPA's data source for tank emissions and tank estimates based on assumptions that more production drives the need for more tanks. The commenter explains that the following is their understanding of the framework that EPA used to justify its regulatory actions for storage tanks.

- First, EPA relied on an array of approximately 100 tanks created for the 2012 Subpart OOOO regulations and then developed emissions estimates for these tanks using the API E&P TANKS program, assuming a 500 b/d throughput and dividing the tank list based on API Gravity to define condensate and crude oil.
- Second, EPA adjusted the tank emissions projections based on flow rates for different size categories and developed a tank inventory based on a ratio of a baseline production value scaled to a projected future value related to total U.S. production.
- Third, EPA projects the number of current wells with and without NSPS OOOO controls.

The commenter believes that these estimates are suspect. The commenter explains that while the assumption that more production drives the need for more tanks is valid at some level such as new unconventional oil and natural gas development, low production well sites (particularly in developed basins) will use existing tanks where capacity is available.

Commenter (0814-IPAA *et al.*) states it is difficult to address the validity of all of EPA's assumptions without access to its various referenced sources and many are not readily available. The commenter believes it is apparent that EPA relied on estimates based on ratios from total production volumes to project the number of tanks in different size categories. For example, where EPA used condensate production reported in the Greenhouse Gas Inventory (GHGI), EPA states:

The 2019 GHGI data indicated that condensate production increased from a level of 145 million barrels per year (MMbbl/yr) in 1992 to 454 MMbbl/yr in 2019 (approximately 288 percent). This 288 percent increase in condensate production was distributed across the model condensate tank batteries in the same proportion as was done for the NESHAP HH rulemaking. Based on this approach, it was estimated that there was a total of 36,501 existing condensate tank batteries in 2019.

Commenter (0814-IPAA *et al.*) believes that other information would produce very different results. By way of example, the commenter states that the Energy Information Administration (EIA) has developed extensive data on oil and natural gas production by size of well. The commenter provides a table in their comment letter which compares 1992 and 2019 (comparable to the years used by EPA), and states that the EIA data shows that condensate production did not

increase by 288 percent; instead, it increased by about 46 percent and also shows that for smaller wells, production changes were on the order of 10 to 15 percent – far less than the total increases.

Commenter (0814-IPAA *et al.*) states that EPA makes a similar error regarding crude oil in estimating the number of new tank batteries, “[u]sing the assumption of four tanks per tank battery (as shown in Table 6-1), EPA scaled the 2006 crude oil storage vessel population to represent 2019 crude oil tank batteries using a ratio of the 2019 and 2006 crude oil tank throughput values from the 2019 GHGI. According to the 2019 GHGI, crude oil throughput increased from 1,679 MMbbl/yr in 2006 to 4,666 MMbbl/yr (an increase of approximately 278 percent) in 2019” but that using EIA information from 2006 and 2019 shows a different result; crude oil production increased by 137.5 percent, and production for smaller wells decreased. The commenter also included a table in their comment letter which summarizes these results.

Commenter (0814-IPAA *et al.*) summarizes that this information calls into question EPA's fundamental assessment that tank construction is producing the substantial numbers of new tanks and inherently using total production increases as a basis to scale up tank numbers is inherently flawed. The commenter states that while oil and natural gas production has increased over the past fifteen years, primarily because of shale oil and shale gas production, production from small wells has been essentially flat and therefore tanks related to smaller operations would not be constructed in any significant amounts. The commenter explains that because of natural depletion, existing tank batteries will have excess capacity that can be used by new wells and these actions will not result in emissions beyond the original design.

Response I-9-46: The commenter appears to suggest that the impacts analysis for storage vessels is inaccurate because we incorrectly assumed that production increases would equally impact small and large producers. The data provided by the commenter suggests that production at small producers (those under 15 bbl/day) is flat and that EPA’s methodology greatly exaggerated the number of new tanks at these small producers. Available EIA data support the commenter’s argument that the increase in production has occurred predominately at higher production rate sites and that production has not increased significantly at the low production rate sites (see: <https://www.eia.gov/petroleum/wells/>). However, we disagree that this suggests our that our national impact analysis is inaccurate. Under nearly all cases, our lowest production model tank battery (with a model throughput of 15 bbl/day) had emissions below the applicability threshold. Thus, while we had assumed a large number of new small tank batteries, these tank batteries were not subject to control requirements, so there were no costs or emission reductions associated with those tanks. We could have assumed, as the commenter suggests, that the number of small tank batteries is flat and it would not have made an appreciable change in our projected nationwide costs and emission reductions. For the larger model tanks batteries (those that we did project would be above the applicability thresholds), we maintain that the percent increase we estimated for these sites is reasonable, considering the commenter’s data. Therefore, we conclude that our projected nationwide costs and emission reductions are accurate, despite our poor assumption regarding the number of new small tank batteries. Other points made by the commenter are addressed in the following paragraphs.

While we have difficulties finding the data used by the commenter because no direct reference was provided, we find that the values in the tables and the commenter’s statements do not appear



to be consistent. For example, for crude oil, the GHGI values and the commenter's values on the increase in production are much more similar than stated by the commenter. Using GHGI data, we estimated crude production increased from 1,679 MMbbl/yr in 2006 to 4,666 MMbbl/yr in 2019. From this, we developed an increase factor of 2.78 (4,666/1,679). The commenter reported total crude production of 1,643 MMbbl/yr in 2006 and 3,902 MMbbl/yr in 2019. While the 2019 value is lower than the GHGI, the increase factor is 2.375. The commenter characterized this as an increase of 137.5 percent and compared it with a 278 percent increase using EPA data. However, if the commenter used a consistent method for characterizing how the "increase" is calculated, the difference is much less stark than indicated by the commenter. Because the higher production facilities are projected to have production increases and because our assumptions for the rate of production increase for these higher production facilities (which are those that are impacted by the rule's control requirements) appears reasonable, we conclude that our national impact estimates for the storage vessel control requirements are reasonable.

With respect to the comment that existing tank batteries will have excess capacity that can be used by new wells, we agree that some facilities may elect to re-use existing tanks. However, with our proposed definition of modification, the owners of these tanks would be required to assess the potential emissions from the tank battery as used in its new service. If the potential emissions from the tank battery exceed the VOC or methane emissions thresholds specified in the rule, this tank battery would be considered to be modified and would be subject to the NSPS standards. Thus, re-use of existing tanks may not increase the total number of storage vessels in operation, it could result in an increased number of storage vessel affected facilities subject to NSPS OOOOb.

### ***9.3.5 Removal of Controls***

Comment: Several commenters (0599-MSC, 0808-API, 0831-AXPC) recommend that EPA preserve the alternative control standard in NSPS OOOOa that allows for a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95 percent control requirement, similar to the 4 tpy provisions for VOC found at 40 CFR 60.5395a(a)(3). Commenter (0808-API) notes that EPA has previously determined that removal of control at 4 tpy VOC will reduce emissions from burning more pilot gas than the waste gas being burned.<sup>53</sup> Commenter (0831-AXPC) states that over time, due to inevitable production declines, there may be an inflection point after which an operator would have to supplementally feed the flare in order to get it to operate, which would result in the emissions from operating the control device exceeding the emissions that would otherwise be vented to the atmosphere and the 4 tpy alternative standard provides the pathway to avoid those unnecessary excess emissions.

Response I-9-47: The final NSPS OOOOb and EG OOOOc allow owners/operators to remove the control device when the actual uncontrolled emissions are maintained below specific thresholds. For NSPS OOOOb, the actual uncontrolled VOC emissions must be maintained below 4 tpy and the actual uncontrolled methane emissions must be maintained below 14 tpy. For EG OOOOc, the actual uncontrolled methane emissions must be maintained below 14 tpy. In

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<sup>53</sup> 5 Federal Register Vol. 78, No. 71, 22133-22134.

both rules, these uncontrolled emissions must be determined monthly for 12 consecutive months. See additional discussion in section IV.J.1.c of the December 2022 Supplemental Proposal.<sup>54</sup>

## 9.4 Cover and Closed Vent System Monitoring

Comment: Commenter (0749-Petroleum Association of Wyoming (PAW)) suggests that EPA allow the use of optical gas imaging (OGI) or other advanced technology (*e.g.*, drone options) for cover and closed vent system monitoring and allow for monitoring with the required fugitive emissions monitoring frequencies to prevent redundancy and undue burden.

Commenters (0781-NTAA, 0605-Muscogee (Creek) Nation) support the strengthening of compliance requirements and monitoring for tank hatches or openings.

Response I-9-48: EPA acknowledges the commenter's support for the requirements for monitoring covers and closed vent systems associated with storage vessel affected facilities. See discussion in section IV.K.1.b of the December 2022 Supplemental Proposal regarding the use of OGI technology and frequency of inspections.<sup>55</sup> See section IV.B of the December 2022 Supplemental Proposal for discussions regarding the use of advanced methane detection technologies for closed vent systems associated with storage vessel affected facilities.<sup>56</sup>

## 9.5 Miscellaneous

Comment: Commenter (0946- Michigan Oil and Gas Association (MOGA)MOGA) felt a disconnect and general lack of understanding of the EPA's previous rulemaking intentions and how the state environmental regulators understood and implemented several of the source definitions and regulations. The commenter states that the storage tank segment particularly is difficult to understand and implement.

Response I-9-49: The commenter did not provide specific details regarding what provisions of the storage segment are difficult to understand and implement, there EPA is unable to respond to the comment.

Comment: Commenter (0809-California Communities Against Toxics (CCAT) *et al.*) states that given EPA's recognition of the importance of regulating all storage vessels that emit significant amounts of VOCs, and the agency's recognition that enhanced regulation of existing sources is needed, EPA should also take this time to revisit the 2012 national emissions standard for hazardous air pollutant (NESHAP) rule's inadequate coverage of this emission source. The commenter explains that the current oil and gas NESHAP covers only storage vessels with the potential for flash emissions (PFE), and only those in the production segment, not the transmission and storage segment.<sup>57</sup> The commenter states that in the 2012 NESHAP rule, EPA stated that it considered promulgating Maximum Achievable Control Technology (MACT)

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<sup>54</sup> 87 FR 74803 (December 6, 2022).

<sup>55</sup> 87 FR 74805-74806 (December 6, 2022).

<sup>56</sup> 87 FR 74740-74741 (December 6, 2022).

<sup>57</sup> See Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 Fed. Reg. at 49,503.

standards for storage vessels without PFE but determined that it did not have adequate data to do so.<sup>58</sup> The commenter states that the failure to act was a violation of EPA's duties under section 112(d)(6), a violation further compounded by the agency's unreasonably long delay in addressing this issue for reconsideration. See *LEAN*, 955 F.3d at 1096. The commenter is concerned that nearly a decade later, EPA has still not fixed this data gap through formal data collection or any other means and states that lack of information cannot be a reason for EPA to not fulfill its duties under the CAA. See *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 644 (D.C. Cir. 2016) ("The Agency was obligated to collect the data it needed, and Congress gave it the authority to do so."). The commenter notes that EPA is specifically aware that adequate and accurate data regarding this significant emissions source within the oil and gas sector is essential for the creation of robust rules<sup>59</sup> and the commenter recommends that accordingly, the agency should take swift action to use its information gathering authority to collect whatever data will assist the agency's needed reconsideration and review of the NESHAP rule, while also serving—and not delaying—completion of the supplemental NSPS proposal and final NSPS rule in the process.

Response I-9-50: These comments are out of scope of this rulemaking.

Comment: Commenter (0782-Berkshire Hathaway Energy Company (BHE)) states that without proposed regulatory text, it is not clear what EPA is considering for tanks in the transmission and storage segment. If something in addition to the NSPS OOOOa requirements is being considered, the commenter encourages EPA to convene discussions with transmission and storage operators to review the NSPS OOOOa requirements and other/additional requirements being considered, including the basis and assumptions that EPA is using to revise or expand requirements. In addition, the commenter recommends including in the Supplemental Notice clear indication that tanks subject to another NSPS, such as NSPS Kb, are exempt from requirements under NSPS OOOOb or EG OOOOc. The commenter suggests that other than the current affected sources in NSPS OOOOa (*i.e.*, transmission and storage tanks with annual VOC emissions exceeding 6 tpy), there is no need for additional requirements for storage vessels located in the transmission and storage segment.

Response I-9-51: See section IV.J of the December 2022 Supplemental Proposal for a discussion of the requirements for storage vessels in all segments of Crude Oil and Natural Gas source category, including storage vessels in the transmission and storage segment.<sup>60</sup> Consistent with the exemption at 60.5395a(e) in NSPS OOOOa, EPA is finalizing language in NSPS OOOOb and OOOOc, stating the requirements for NSPS OOOOb and EG OOOOc do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

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<sup>58</sup> Id. at 49,532.

<sup>59</sup> See Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards; Proposed Rule, 78 Fed. Reg. 22,126, 22,129-30 (Apr. 12, 2013) (revising estimates of the number of impacted storage vessels based on new data).

<sup>60</sup> 87 FR 74800 (December 6, 2022).

## Chapter 10. Pneumatic Controllers

### 10.1 General Support/Opposition for Proposed Pneumatic Controller Standards

#### 10.1.1 General Support for Zero Emissions Standard for Pneumatic Controllers

Comment: Several commenters (0185-Mokveld Valves BV (Mokveld), 0391-Keweenaw Bay Indian Community (KBIC), 0401-Mercy Investment Services, Inc. (Mercy), 0434-Impax Asset Management, LLC (Impax), 0435-Wespath Benefits and Investments (Wespath), 0437-New York Office of the State Comptroller (NYOSC), 0443-Seventh Generation Interfaith Inc. (SGI), 0444-Damascus Citizens for Sustainability (DCS), 0460-Trinity Health, 0538-Change Finance, PBC (Change Finance), 0560-Legal & General Investment Management America, Inc. (LGIM America), 0605-Muscogee (Creek) Nation, 0720-Miller/Howard Investments, Inc. (MHI), 0723-Ceres, 0724-Boston Trust Walden (BTW), 0728-Calvert Research and Management (Calvert), 0729-Energy Workforce & Technology Council (EWTC), 0737-Clarke Valve, 0781-National Tribal Air Association (NTAA), 0812-Ohio Farmers Union (OFU) *et al.*, 0823-Qnergy, 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 0844-Environmental Defense Fund (EDF) *et al.*, 0918-Colorado Local Government Coalition (COLGC), 0941-350 Silicon Valley, 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD), 1267-California Office of the Attorney General (CA AG) *et al.*, 1282-Earthworks, 1372-Generate Capital, PBC (Generate), 1389-VERIS Wealth Partners) support the requirement for new sources to use zero emitting technologies. These commenters also support the November 2021 Proposal to remove the exemption for higher bleed pneumatic controllers based on functional needs, except in very limited circumstances. Commenters also provide support for EPA's November 2021 Proposal to apply presumptive emissions limitation standards for existing pneumatic controllers that are the same as those required for new sources. Commenters note that the experience of leading operators demonstrate zero-emitting pneumatics are widely available and cost-effective to deploy.

Commenter (0844-EDF *et al.*) encourages EPA to include in its final rule a requirement that operators use zero-bleed technology for intermittent controllers. The commenter notes that EPA studies have shown that even when operating properly, intermittent controllers emit a significant amount of methane, and often function improperly by emitting continuously rather than only when actuating. Although the specific percentage of malfunctioning devices varies considerably, the commenter notes that studies confirm that intermittent controllers can and often do emit far more than their advertised design values indicate. The commenter contends that these excess emissions can be easily and cost-effectively avoided by requiring operators to use the zero-emitting options discussed above for intermittent controllers.

Commenter (0823-Qnergy) states that through their company's technology, the industry has demonstrated the ability to reduce emissions from pneumatic controllers and pumps to the degree identified in the November 2021 Proposal and that their technology should form the basis of the proposed BSER for pneumatic controllers and pumps. The commenter cites specific CAP3 product and technology performance data. The commenter adds that its technology can replace all controller types, regardless of whether they are continuous bleed natural gas driven or

intermittent natural gas driven. The commenter notes that, with zero- or near-zero emissions technology that uses compressed air available, the natural gas bleed rate becomes irrelevant.

Response I-10-1: The EPA is requiring zero emissions from process controllers in the final NSPS and EG. See discussion in section IV.D.1.b.ii. and iii. of the December 2022 Supplemental Proposal preamble (87 FR 74760-74766) and section XI.D.3 regarding the EPA's conclusions regarding zero-emissions technologies as the BSER for process controllers.

### ***10.1.2 General Opposition to Proposed Standards***

#### **10.1.2.1 Zero Emission Intermittent Vent Controller Exemption Request**

Comment: Commenter (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) states that it is not reasonable, cost-effective or efficient for operators, especially marginal/low production well operators to now replace well-functioning intermittent vent controllers or retrofit their sites to use air-driven, solar, electric, or self-contained controllers. According to the commenter, many of these options are not feasible, reliable, safe, or economic for all sites. In addition, the commenter notes that the replacement devices are not readily available or field-tested in a way that would make them safe for mass deployment. The commenter recommends that EPA remove this requirement for zero-emission intermittent vent controllers. As an alternative, they suggest that EPA could include these under the fugitive emission monitoring requirements to ensure malfunctioning controllers are addressed.

Response I-10-2: See discussion in section IV.D.2.c. of the December 2022 Supplemental Proposal preamble (87 FR 74768) and section XI.D. 3 of the preamble to the final rule regarding the zero-emissions requirement for existing sources.

#### **10.1.2.2 Zero-emitting Pneumatics are Overly Burdensome and Not Cost-Effective**

Comment: Commenter (0764/0564-Arkansas Independent Producers and Royalty Owners (AIPRO)) notes that another commenter (0808-American Petroleum Institute (API)) has presented EPA with detailed comments regarding the technical feasibility and cost effectiveness for moving to zero-emitting pneumatic devices and controllers at existing facilities. The commenter supports the comments provided by the commenter (0808-API) on this topic. As proposed, the commenter states that the requirements for zero-emitting pneumatics are overly burdensome and not cost-effective. According to the commenter, the consequences to low production wells and small business would be significant. Most importantly, the commenter adds that the reduction in emissions for many companies will be negligible as pneumatic process emissions, when using EPA default factors and methodologies, are vastly overstated, in some cases by 90 percent or more. The commenter states that there are additional issues with grid power availability, right-of-way for grid power, off set emissions for combustion sources to provide electricity for electric pneumatics or compressed air, reliability of either grid power or

solar power, and operating ranges of battery storage for different geographical locations among other issues.

Another commenter (0938-Texas Oil & Gas Association (TXOGA)) contends that EPA's November 2021 Proposal is not cost-effective or feasible in all situations and suggests that EPA reconsider its approach. The commenter reports that their members would oppose any requirement to use non-emitting controllers at existing sites; among other considerations, electrifying existing sites would likely be problematic due to right-of-way issues and the availability of electricity. According to the commenter, problems include issues with implementing alternate power sources, such as solar, and other considerations that they contend that EPA's November 2021 Proposal does not properly address.

Response I-10-3: See discussion in section IV.D.2.c. of the December 2022 Supplemental Proposal preamble (87 FR 74768) and section XI.D. 3 of the preamble to the final rule regarding the zero-emissions requirement for existing sources.

#### 10.1.2.3 Request to Allow the Use of Low Bleed Pneumatic Controllers under Emissions Guidelines

Comment: Commenter (0911-North Dakota Petroleum Council (NDPC)) posits that the pneumatic controller emission factors in 40 CFR 98 overestimated the emissions from this source category and that EPA's focus on regulating these sources is unwarranted. The commenter notes that the leak detection and repair (LDAR) programs, as required by new source performance standards (NSPS) OOOOa, states, and voluntary programs, will assure that maintenance of pneumatic controllers is performed promptly. On existing sources in particular, the commenter recommends that EPA allow for the use of low bleed pneumatic controllers under emission guidelines (EG) OOOOc. The commenter explains that this would appropriately balance significant environmental benefits with the multitude of challenges associated with implementing changes to pneumatic controllers for all existing sources. The commenter also believes the secondary emissions created by these proposed requirements to make the pneumatic controllers non-emitting (*e.g.*, from manufacturing of new equipment and installation of alternative equipment) could be more significant than what the source emits during its useful life.

Response I-10-4: See discussion in section IV.D.2.c. of the December 2022 Supplemental Proposal preamble. See 87 FR 74768. See also the response to similar comments submitted regarding the December 2022 Supplemental Proposal, in Volume II, Chapter 7 (Process Controllers), subsection 7.3.1 (NSPS OOOOb and EG OOOOc BSER Analysis/Emissions/Costs, Emissions/Emission Factors), Response II-7-62.

#### 10.1.2.4 Zero-emitting Pneumatics Present Challenges in Some Locations and Applications

Comment: Commenter (0817-GPA Midstream Association (GPA)) does not support a requirement for zero-emission controllers for all locations and applications because of what they contend are various practical challenges with imposing that requirement. Nonetheless, the commenter suggests that, if EPA finalizes such a standard, it should do so without requiring the use of any particular technology. The commenter states that the November 2021 Proposal leans

heavily on the use of electrically actuated controllers and solar-powered controllers. The commenter suggests, however, that EPA overestimates the effectiveness and reliability of both, which have significant drawbacks. If a standard is mandated, the commenter notes that a technology-neutral standard would allow companies to achieve a zero-emission standard based on the particular circumstances of each midstream facility, such as location and access to electricity. Regardless of the technology used, the commenter states that the logistical difficulties require a longer compliance period. Finally, the commenter adds that although a zero-emission standard can be implemented for many applications, other applications should be exempted for safety and environmental reasons.

Response I-10-5: See discussion in section IV.D.1.b.i. of the December 2022 Supplemental Proposal preamble for discussion of exemptions (87 FR 74759). See also section XI.D.2 (Zero-emissions standard) of the final rule preamble for the EPA's responses to comments received on the proposed zero-emissions standard for process controllers. See section XI.D.4 (Compliance dates) of the final rule preamble for the EPA's response to comments on the need for a longer compliance period for new sources. See Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), and 7.5 (Applicability and Compliance Date Considerations) Responses II-7-80 and II-7-82 for the EPA's response to comments on the need for a longer compliance period for existing sources.

## **10.2 Affected Facility, Modification and Reconstruction Definitions**

### ***10.2.1 Affected Facility Definition***

Comment: Several commenters (0599-Marcellus Shale Coalition (MSC), 0777-Ascent Resources, LLC (Ascent), 0808-API, 0817-GPA, 0938-TXOGA) contend that there is a disconnect between the pneumatic controller affected facility definition (*i.e.*, an individual controller) and the cost analysis, which was based on the replacement of all pneumatic controllers with zero-emitting devices at a site. The commenters recommend that EPA not define the affected facility as each individual controller but rather as the group of all controllers at a site. Commenters (0599-MSC, 0831-American Exploration and Production Council (AXPC)) add that this approach would be more consistent with EPA's cost analysis which assumed the control options would occur at the site level and not just for an individual controller. Commenters (0777-Ascent, 0817-GPA) state that defining the affected facility on a site-wide basis aligns with how emissions from pneumatic controllers will likely be handled by owners and operators of oil and natural gas facilities and provide flexibility that will help owners and operators in designing and operating the kind of capture-and-control system that would ensure a 95 percent volatile organic compound (VOC) or methane reduction from the entire population of gas driven pneumatic controllers at a particular site. Commenter (0808-API) suggests the following affected facility definition:

Each pneumatic controller affected facility, which is the collection of natural gas driven pneumatic controllers that vent to the atmosphere located at a well site, centralized production facility, or compressor station.

Another commenter (0742-Alaska Department of Environmental Conservation (ADEC)) suggests that there are complexities of tracking and managing the universe of pneumatic controllers at a site when only a portion of the universe of pneumatic controllers are affected facilities and recommends that EPA propose a simpler system to ease compliance efforts.

Response I-10-6: See discussion in section IV.D.1.b.i. of the December 2022 Supplemental Proposal. See 87 FR 74756-74757.

As noted above, the pneumatic controller affected facility definition changed from being based on a single continuous bleed or intermittent vent controller in the November 2021 Proposal to the collection of continuous bleed and intermittent vent controllers at a site in the December 2022 Supplemental Proposal. EPA is proposing this change based on information received from commenters.

We agree with the commenters that defining the pneumatic controller affected facility as the collection of all controllers at a site is the most practical approach. Significantly, most of the zero emissions measures for pneumatic controllers are site-wide solutions. For instance, a compressed air system installed at a site would be used to power all the pneumatic controllers at the site, rather than a separate system for each controller. Similarly, a solution based on solar energy would likely utilize a single array of solar panels to provide power to all the controllers at the site. In fact, as pointed out by the commenters, the analysis for the November 2021 proposed rule was conducted on a “model plant” site-wide basis.

Comment: Commenter (0782-Berkshire Hathaway Energy Company (BHE)) recommends limiting pneumatic controller provisions applicability to compressor stations, and not to locations along natural gas transmission pipelines (*i.e.*, exclude the limited applications along transmission pipelines). The commenter states that for pipeline applications, EPA could consider the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) programs under development that are reviewing pipeline-related emissions, and coordinate with that process. The commenter suggests that applicability be limited to compressor stations because pipeline emissions are relatively low, and PHMSA has required operators to update operation and maintenance (O&M) procedures to ensure methane emissions are reduced. In response to that 2021 PHMSA requirements, the commenter states that the agency is implementing a review program in 2022 to test progress and assess O&M Plans.

Response I-10-7: The EPA has found the BSER for all location types to be zero emissions, except at sites in Alaska without access to electrical power. The NSPS and EG incorporate the BSER, and therefore, regardless of other standards or requirements instituted by other programs or agencies, all locations, except sites in Alaska without access to electrical power, are required to have zero emissions.

### ***10.2.2 “Non-emitting” Versus “Zero emitting” Pneumatic Controller Terminology***

Comment: Commenters (0425-Darrah Oil Company, LLC (Darrah), 0764-AIPRO, 0808-API, 0831-AXPC) support efforts to reduce emissions from pneumatic devices and the approach of moving towards non-emitting pneumatics at newly constructed sites. However, the commenters



believe some clarification is needed and recommend that EPA use the term “non-emitting” versus “zero-emitting.” As a practical matter, they explain that the term “zero-emissions” is apt because the object of the November 2021 proposed standards is to eliminate methane and VOC emissions from the affected facility. But as a legal matter, the commenters state that the term “zero-emissions” is imprecise and in error because these standards impose equipment or work practice obligations and do not impose a numeric emissions limitation of zero.

Commenter (0425-Darrah) states any requirement of “zero” creates a likelihood of waste as incremental gains come at higher and higher costs. To have “extremely low” as acceptable emissions may be reasonable, but the word zero may set goals where you do more environmental damage by replacing or retiring equipment before the end of its useful life in the name of “zero.”

According to the commenters (0764-AIPRO, 0808-API, 0831-AXPC), the legal distinction is important because a fully compliant pneumatic controller or liquids unloading event may still have incidental VOC and methane emissions. The commenters state that no piece of equipment or work practice is perfect – even if implemented according to best practices. Thus, the term “zero-emissions” expresses an idealized outcome that is belied by reality. A zero-emissions numeric standard would unreasonably cause incidental emissions to be a violation of the standard. EPA should correct its terminology in the Final Rule by stating that non-emitting control measures under this rule are work practices.

Response I-10-8: See discussion in section IV.D.1.b.i of the December 2022 Supplemental Proposal (87 FR 74759 and footnote 126) regarding the term “zero-emissions.”

### ***10.2.3 Modification or Reconstruction of Affected Facility***

Comment: Commenters (0817-GPA, 0831-AXPC) recommend that EPA allow like-kind replacement of existing individual controllers without causing the controller to become an affected facility under the November 2021 proposed NSPS OOOOb. The commenters indicate that if EPA does not allow this, operators who are voluntarily replacing high-bleed natural gas-driven controllers with low-bleed controllers would likely stop doing so. Other commenters (0564-AIPRO, 0599-MSC, 0808-API) state that they were unable to assess the feasibility of proposed requirements for modified sites because EPA has not delineated how modification of controllers is determined given the new control strategy proposed under the November 2021 proposed NSPS OOOOb. The commenters suggest that EPA define a modification to a collection of natural gas driven pneumatic controllers be defined similar to how EPA has defined modification in 40 CFR 60.5365a(i) and (j) for well sites, tank batteries, and compressor stations. Under this concept, when a modification occurs, the operator would be required to retrofit the collection of pneumatic controllers at the well site, tank battery, or compressor station to non-emitting controllers.

Response I-10-9: See section IV.D.1.b.i. of the December 2022 Supplemental Proposal (87 FR 74758-74759) for the EPA’s response to this comment.

## 10.3 Alternative Control Options

### 10.3.1 *Allow for Flexibility of Technologies Used to Achieve Standards*

Comment: Commenters (0599-MS, 0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ), 0831-AXPC, 0919-TEP Rocky Mountain, LLC) recommend that EPA allow for the use of various technologies to achieve “non-emitting” status, including the option of routing to an existing control device if it is feasible to do so. Commenters note that the best path to achieve a “non-emitting” threshold for pneumatic devices will be different for each site based on the specific site design, operation, and circumstances. For example, upstream facilities are often located in remote locations without access to grid power, which may necessitate multiple solutions to achieve a “non-emitting” standard. According to commenters, developing adequate power supply to remote locations, such as are typical in upstream development, can present significant challenges. As most upstream site locations are leased, not owned, and facilities are temporary (not permanent) it is not always realistically feasible to electrify a location from the grid due to issues outside the operator’s control. Similarly, the viability of solar-powered technologies is still being evaluated and has presented reliability challenges to several of the commenter’s member companies who have piloted their use in the field. Similarly, commenters add that, where weather can be a limiting factor, operators may need a different suite of solutions to manage that dynamic. Examples provided to reduce these emissions include, but are not limited to, pneumatic controllers driven by compressed instrument air, electric controllers, mechanical controllers, and routing natural gas controllers to a process, sales line, or combustion device.

Commenter (0808-API) notes that state precedents allow flexibility in control options citing regulatory language for Colorado and New Mexico which allows all options mentioned above and describes them as “non-emitting controllers.

Commenter (0743-Western Energy Alliance (WEA)) notes that their members in basins across the country have taken on projects to retrofit facilities with intermittent bleed and low bleed controllers, outfitted facilities with instrument air equipment, and routed emissions from facilities to control devices where possible. However, the commenter reports that these retrofits and equipment modifications are not applicable in all scenarios. For this reason, the commenter recommends that EPA allow more flexibility in any proposed pneumatic controller requirements.

Commenter (0817-GPA) suggests that EPA affirm that the zero-emission standard is technology neutral and not limited to just solar powered electric actuators and instruments. The commenter states that this would allow midstream companies to adopt an approach best suited to a facility’s individual characteristics (*e.g.*, distance from population centers, weather, availability of electricity) and the development of new technologies that may alleviate some of the trade-offs inherent in each type of zero-emission controller.

Response I-10-10: The zero-emissions requirements of the final NSPS and EG are technology-neutral. See section XI.D.2 of the preamble to the final rule for discussion of the determination of BSER for process controllers.

### ***10.3.2 Capture Emissions and Route to a Combustion Device or Process Sales Line***

Comment: Several commenters (0749-Petroleum Association of Wyoming (PAW), 0808-API, 0830-Devon Energy) request that EPA include an option to collect the emissions from natural gas-driven controllers and route them to a flare or combustion device that achieves 95 percent reduction in methane and VOC. These commenters note that in many situations, an onsite control device already exists and that using it would be a cost-effective method of achieving significant emission reductions.

Commenter (0777-Ascent) notes that EPA did not evaluate capture and 95 percent control as a compliance option for pneumatic controllers. Based on the commenter's concerns regarding the elimination of gas-driven controllers, it conducted a recent pilot program in which it has evaluated the technical feasibility of capturing the emissions from gas-driven pneumatic controllers and routing those emissions to a thermal control device. The commenter contends that this manner of control is technically feasible in certain applications and may, provide a way to ensure significant reductions in emissions from pneumatic controllers while addressing the operation and reliability concerns associated with eliminating gas-driven controllers using other zero-emitting technologies.

Another commenter (0749-PAW) states that routing methane emissions from gas-actuated controllers to a combustion device is a control technique that is currently used in the industry in some production facility operations for other emission sources (tanks, dehydrators, *etc.*). Therefore, the commenter states that the additional cost burden would be significantly less and estimated at approximately \$2,000 per well site. The commenter adds that compliance is assured in that leak detection is conducted as part of the required fugitive emissions monitoring and monitoring of pilot temperature can be a method for monitoring the enclosed combustor's performance and assuring effective emission control.

Commenter (0830-Devon Energy) notes that Colorado<sup>1</sup> and New Mexico<sup>2</sup> consider pneumatic controllers that route emissions to be considered "non-emitting controllers" and therefore recognize this control technology to provide sufficient emission reductions under those programs.

Another commenter (0599-MSO) supports routing of pneumatic controllers to a combustion control device or process for new sources, however, the commenter notes that for existing pneumatic controllers, adding a control device specifically for pneumatics would be hindered by cost (older, low-producing pads and smaller facilities), availability, and other constraints such as spacing of a combustion device (setbacks, safety, and smaller locations that may lack the room).

Response I-10-11: See section IV.D.1.b.iv of the December 2022 Supplemental Proposal (87 FR 74765-74766) for the EPA's response to this comment and section XI.D.2 of the preamble to the

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<sup>1</sup> [https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn\\_Z0x50X/view](https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view)

<sup>2</sup> <https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf>

final rule for the EPA’s response to similar comments made on the December 2022 Supplemental Proposal.

### ***10.3.3 Limitations to the Use of Solar-powered Controllers***

Comment: Several commenters (0743-WEA, 0749-PAW, 0793-Permian Basin Petroleum Association (PBPA), 0808-API, 0817-GPA, 1391-Interstate Natural Gas Association of America (INGAA)) maintain that there are significant technical limitations to using solar powered controllers to replace pneumatic controller driven by natural gas at sites without electricity.

Commenter (0793-PBPA) states that while EPA has suggested the use of onsite solar generation paired with battery storage as an alternative to grid electricity, such systems are currently “uncommon, unreliable, and will likely increase the frequency of facility upsets, which will increase safety risks such as overpressure events and spills.”

Another commenter (0599-MSD) states that while there may be some pilot projects within the industry, it has not been demonstrated that reliable turnkey packages are available on a widescale basis.

Commenter (0817-GPA) states that EPA relies on a report by Carbon Limits, a Norwegian consultant, called “Zero Emission Technologies for Pneumatic Controllers in the USA, Applicability and Cost Effectiveness” (Aug. 1, 2016) (“Carbon Limits”). (See November 2021 Proposal Technical Support Document (TSD) at 8-24.) Based on interviews, the commenter notes that Carbon Limits identified less than 100 installations of solar powered controllers. Carbon Limits at pg. 34. According to the commenter, these would almost certainly be installed only in the environments most advantageous to solar power, such as sunny, warm, and open areas without terrain that could block sun exposure.

Several commenters note that there are severe geographic limitations to the use of any solar-powered devices. Commenter (0817-GPA) states that West Virginia averages only 164 days of sunshine per year, compared with an average of 205 days for the rest of the U.S. The commenter adds that, even in typically sunny states, operations in canyons or mountain valleys receive significantly limited sunlight exposure. They further add that snow and ice also raise additional reliability concerns during winter months.<sup>3</sup>

Commenter (0599-MSD) states that large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (e.g., Colorado, North Dakota, Idaho, and Wyoming).

Other commenters (0740-Utah Petroleum Association (UPA), 0743-WEA) agree that solar power might be an option but report that their member companies have not yet been able to demonstrate this to be universally true in Utah’s Uinta Basin. Commenter (0743-WEA) notes that, as an example, in the Uinta Basin, there are certain times of year where fog can sit over the basin for several weeks, effectively making solar controllers useless. According to the

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<sup>3</sup> The Carbon Limits Report, based on a single interview, notes snow as a “technical challenge” for solar panels and battery life, Carbon Limits at 15, but did not elaborate further.

commenter, in much of that area electrical power is also unavailable. For this reason, the commenter states that, if portions of Alaska are exempt from the November 2021 proposed requirements, then other areas of the country need to be evaluated as well. The commenter adds that, (1) in the West, line power is often unattainable where endangered species concerns preclude the construction of power lines and other infrastructure; (2) Northern basins have concerns with cloud cover, snow, and battery reliability; and (3) Southern basins have concerns with dust and heat/humidity related battery reliability. The commenter contends that these concerns are not effectively addressed in the November 2021 Proposal.

Commenter (0808-API) also mentions that it is probable that supplemental power via natural gas or diesel-powered generators could be required during winter months and/or severe weather events, which would be necessary to ensure a continuous power supply, and, thus, a controlled operation. This commenter also notes that interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess emissions associated with equipment malfunctions.

Commenter (0808-API) indicates that they are unaware of any operators converting to solar-powered electric controllers at this time. They note that while the technology seems promising, many of these solar systems have not yet been proven reliable for all remote locations or facility designs and are not ready for deployment across the country at the large-scale EPA's November 2021 Proposal would require. They note that in 2014, EPA stated "solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry."

Conversely, commenter (0838-TRIDO Solutions LLC) supports EPA's November 2021 Proposal to require zero-emission controllers. The commenter notes that they are a technology company that tackles methane emissions by replacing pneumatic devices and pumps with solar-powered pumps and air compressors. The commenter states that, initially designed for the aerospace industry, their differentiating technology is its high-efficiency motor and controller. The commenter cites several state rules that require all new pneumatic controllers to be non-emitting, including states with colder climates (*e.g.*, CO, WY, OK).

Commenter (0451-Clean Air Task Force (CATF)) states that, in a supplement to their 2022 report that was provided in a late comment, Carbon Limits addressed many of the alleged shortcomings of solar and other zero-emitting controller technologies raised in public comments. They state that, "[a]ddressing the queries on the reliability of solar systems for remote locations and cold states, the technology providers and operators interviewed as part of this assessment have solar-powered controllers installed at well sites in remote and cold locations such as Northern Alberta and British Columbia, without major reliability issues. Some of the interviewed technology providers have installed these systems in over 400 well-sites in these states and provinces. The commenter noted that solar technology has improved drastically from 2014 to 2021. Efficiency has increased while costs have gone down significantly. Solar-powered controllers can operate at low temperatures and remote locations, among different gas sectors. When it comes to snow cover on panels affecting the performance of solar cells, all the interviewees stated that the panels are placed at a low angle, to catch ample sun in the winter

months. Most often, these panels are placed vertically, eliminating snow cover on the solar panels.

Response I-10-12: Similar comments on the reliability of solar-powered process controllers were provided on the December 2022 Supplemental Proposal. For response to this comment, please see Volume II, Chapter 7 (Process Controllers), subsection 7.2.3 (Solar), Responses II-7-33 and II-7-34. See also section XI.D.2 (Zero-emissions standard) of the final rule preamble for EPA's responses to comments received on the proposed zero-emissions standard for process controllers.

Comment: Several commenters note that there are additional costs and risks associated with the implementation of solar-powered controllers that were not considered by EPA in the November 2021 Proposal analysis. The commenters recommend that EPA gather substantially more data and factor in necessary costs and risks, before proposing to impose a standard that assumes solar power is a viable option across the midstream sector. The following specific concerns are noted by commenters:

*Additional costs*

- Dispatching personnel to ensure that solar panels are cleared and functional at unmanned facilities. (0817-GPA)
- The full cost of siting solar power and associated equipment. Even where solar panels have adequate sunlight exposure, relatively small solar panel arrays are unlikely to meet the power demand for controllers and other equipment. The commenter states that a battery bank to supply power to the controllers at an entire compressor station could require as much as two acres of solar panels.<sup>4</sup> The November 2021 Proposal did not consider the potential for the need to acquire land and the cost of land acquisition and related permitting. (0817-GPA)
- EPA estimated a battery life of 15 years. There is no demonstrated experience to support that assumption across even a moderate sample size for this type of activity in the challenging environments where midstream activities are located. Cold weather decreases battery output and overall battery life therefore, batteries will likely have to be replaced far more frequently than 15 years. (0817-GPA)
- Additional labor or contract costs would be incurred to remotely monitor batteries and maintain charging stations to support the operation. (0817-GPA)
- EPA did not consider the costs associated with backup power system. Without adequate field-testing of solar powered systems, it is probable that via natural gas or diesel - powered generators would be required during winter months and/or severe weather events. This is necessary to ensure a continuous power supply, and, thus, controlled operation. (0808-API)

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<sup>4</sup> According to the commenter, for compressor stations, it is simply not practical to have a solar panel for each controller. The commenter asserts that the Carbon Limits report is not clear, but its discussion of solar powered controllers implies that it examined solar panels to power a relatively small number of controllers at well sites. Carbon Limits at 13-16. Indeed, Carbon Limits states that, because "providers have so far focused mainly on the development of solutions for small sites in remote locations," there "seems to be much less field experience with using electronic controllers at medium and large sites" and is "not aware of any such installations." Id. at 16. 10 Cf. Carbon Limits at 15.

- The type and number of batteries required for remote industrial sites (e.g., gel lead acid batteries and absorbed glass mat (AGM) batteries) are on average higher in cost as compared to household solar panel systems. (0808-API)

*Risk related to practicality and reliability*

- Routine essential maintenance for clearing snow from panels is something that would be impractical for remote areas in winter months. (0817-GPA)
- Industry experience operating unmanned facilities in rural areas is that equipment theft is a significant concern, and large-scale batteries would likely be a prime target for theft, also thus increasing costs.<sup>5</sup> (0817-GPA)
- Where land acquisition is required, an assumption cannot be made the sufficient land is available. (0817-GPA)
- The electrically actuated controllers are less reliable and not appropriate for all process conditions such as throttle service. Adding the uncertainty of solar panels and batteries to these existing limitations will create more issues at these remote, unmanned sites that may lead to additional unplanned downtime. (0817-GPA)
- As a result of unplanned downtime at a compressor station, the compressor station can be forced to blowdown equipment which releases natural gas to the atmosphere. This would be especially true at older, existing compressor stations. Likewise, the upstream well sites can be forced to either vent or flare gas when the downstream compressor station is not available which would create a combination of additional emissions. (0817-GPA)
- Where sites experience significant winter weather or obstructions to sunlight, this type of high-maintenance equipment is impractical to operate. (0817-GPA)
- The potential exists that well sites would not generate enough power with a solar array, which would potentially require large and expensive battery storage system (1341-Conventional Groups)
- Large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (Colorado, North Dakota, Idaho, Wyoming, etc.). (0808-API)
- Effect of climate and atmospheric conditions:
  - Reduced sunlight for long periods including fog. In the Uinta Basin, there are certain times of year where fog can sit over the basin for several weeks, effectively making solar controllers useless. In much of that area electrical power is also unavailable. In the West, line power is often unattainable where endangered species concerns preclude the construction of power lines and other infrastructure. Northern basins have concerns with cloud cover, snow, and battery reliability. Southern basins have concerns with dust and heat/humidity related battery reliability. (0743-WEA)
  - Average ambient temperature. At temperatures at or below -20°C (-4°F), solar battery capacity is decreased to 50 percent. This reduces the overall life of the solar battery, which impacts the overall reliability and lifespan of the system. Further, if low temperatures cause freezing, an interruption to power supply for the pneumatic controller system will occur. (0808-API)

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<sup>5</sup> Cf. Carbon Limits at 15. 11 The Carbon Limits Report stated that a challenge for solar panels was that they “have reportedly been stolen or used as targets for shooting.” Carbon Limits at 15.

- Particulate accumulation. The level of particulate accumulation on the solar panel(s) is not well documented. This is important for remote, unmanned sites as challenges associated with properly cleaning the panels are encountered. The decrease in energy loss due to particle accumulation greatly varies based on several factors including site location, surrounding soil type, dust characteristics, and other surrounding air pollution.<sup>6</sup> One study suggests that in the U.S. over a 3-month period, up to 4.7 percent solar capacity is lost due to particulate accumulation on solar panels.<sup>7</sup> (0808-API)
- The effect of extreme temperatures on the capacity to store and deliver power. Remote oil and gas site applications for solar installations typically require up to 1,600 watt, 24 volts direct current (VDC) capacity with a common battery type being an 8G8D gel cell (number of batteries required per application can range from 2 to more than 10). The exact number of solar sets is greatly variable based on site-specific requirements.<sup>8</sup> When sizing the solar system, in addition to site-specific requirements, the temperature profile of the site also impacts the type, number, and capable performance of batteries for solar packages.

For example, the Deka 8G8D battery has an operating temperature range from -30°C (-22°F) to 50°C (122°F); however, the optimal operating range is above 0°C (32°F) because cold temperatures increase the internal resistance of a battery, thereby reducing capacity. The standard capacity rating of this example battery is based on each cell having an electrolyte temperature of 20°C (68°F).<sup>9</sup> At temperatures below the nominal rate, the battery's effective capacity is reduced, and the time to restore the battery to full charge is increased exponentially with decrease in temperature. Commenter provides a figure depicting the relationship between battery capacity and temperature for a Deka 8G8D solar battery, which indicates at -20°C (-4°F), battery capacity is decreased to 50 percent. The commenter provides a table which shows six states with significant oil and gas operations where temperatures fall in the range for reduced solar battery capacity during winter. Further, it is noted that the recent unprecedented winter storm in Texas (February 2021) saw a low temperature of -27° (-16°F).<sup>10</sup> Unfortunately, during severe weather days including snowstorms, solar panels are often not receiving sunlight and battery power is being used. Sufficient battery power at a high charge is needed for at least 7-10 days without sun. If the decreased sunlight lasts for too many days, batteries can freeze. Solar batteries in the oil field often freeze and stop functioning, particularly in areas where temperatures can drop to -40°C (-40°F).

On the other hand, extreme heat can also negatively affect battery performance and reliability. Though temperatures above 25°C (77°F) will slightly increase capacity, the

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<sup>6</sup> Renewable and Sustainable Energy Reviews, Volume 59, June 2016, Pages 1307-1316. Renewable Power loss due to soiling on solar panel: a review, Mohammad Reza Maghami.

<sup>7</sup> Hottel, H, and Woertz, B. Performance of flat-plate solar-heat collectors. United States.

<sup>8</sup> Example of solar installations at oil and gas sites: <https://www.scadalink.com/products/remote-power/industrial-solar-panels/>.

<sup>9</sup> Deka battery specifications: <https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries>

<sup>10</sup> Feb. 2021 Texas Winter Storm Details: <https://www.weather.gov/media/ewx/wxevents/ewx-20210218.pdf>.



potential of self-discharge and reduced battery life is increased. Further, as temperatures rise, any cycle life loss due to operating at higher temperatures is not recoverable. During extreme heat events, such as those experienced in Texas and Louisiana, overheating of the battery is possible. In this scenario, the battery lifespan can be shortened, or the battery can be completely damaged. (0808-API)

Response I-10-13: Similar comments on the reliability of solar driven process controllers were provided on the December 2022 Supplemental Proposal. For response to this comment, please see Volume II, Chapter 7 (Process Controllers), subsection 7.2.3 (Solar), Responses II-7-33 and II-7-34.

#### ***10.3.4 Instrument Air***

Comment: Commenter (1341-Conventional Groups) states that even if a reliable electric source were available at the well sites of their industry members, the use of gas-fired compressors to operate instrument air would result in a net increase in emissions. The commenter notes that the EPA acknowledges that instrument air systems are feasible "only at locations with a high concentration of pneumatic control valves" (November 2021 TSD, p. 8-17). The commenter reports that their member company well sites do *not* have a high concentration of such valves.

Response I-10-14: For discussion of secondary emissions from process controllers powered by generators, see section IV.D.1.b.iii. of the December 2022 Supplemental Proposal preamble (87 FR 74765) and section XI. D.2 of the preamble to the final rule. In the 2021 TSD, the EPA did not acknowledge that instrument air systems are infeasible unless there are a high concentration of pneumatic control valves, but rather assumed that other options, such as solar-powered electric process controllers would be used at sites with only a few process controllers. See also section IV.D.2.d.i of the December 2022 Supplemental Proposal (87 FR 74769) and section XI.D.2 of the preamble to the final rule for discussion of small well sites.

Comment: Commenter (0823-Qnergy) states that they produce compressed air pneumatic systems (CAP3) to displace methane and VOC emissions from pneumatic devices. The commenter reports that they developed an application allowing its Stirling generators to power CAP3, even when grid power is not available. The commenter adds that CAP3 leverages the reliability of their power generators to drive compressors that replace methane emissions from pneumatic devices with clean, dry instrument air. According to the commenter, this technology offers a low-emission alternative to the gas-powered pneumatic devices currently used throughout the natural gas industry, particularly in the upstream sector.

Based on a range of capacities and operating conditions, the commenter (0823-Qnergy) notes that each of their CAP3 systems can abate between 500 and 5,000 tons of carbon dioxide (CO<sub>2</sub>) equivalent per year. They add that their CAP3 system meets EPA's proposed standards of performance for zero-emissions controllers and a natural gas emission rate of zero both on and off the grid.<sup>11</sup> The commenter notes that their internal testing has demonstrated that their

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<sup>11</sup> When operating off the grid, the commenter states that the CAP3 system produces only negligible emissions of CO and NO<sub>x</sub> (ten- to a hundred-fold less than internal combustion engines (ICEs)) from the Stirling engine's power

technology not only eliminates “bleeding” natural gas at well sites effectively, but it does so at the lowest emissions abatement costs of any pneumatic technology.<sup>12</sup> The commenter provides technical descriptions of various CAP3 models and notes that they continue to expand use of their systems in wide-ranging environments on the North American continent. According to the commenter, they recently raised capital from the Oil & Gas Climate Initiative to accelerate deployment of its methane mitigation systems throughout the world, with a focus on the natural gas exploration, production, and transport markets.<sup>13</sup>

In response to EPA’s request for information on specific functional needs that would require a low-bleed or intermittent controller, commenter (0823-Qnergy) provides that their CAP3 technology can be applied to all pneumatic controller types, eliminating the need to vent natural gas to the atmosphere. According to the commenter, while low-bleed and intermittent controllers are prevalent in the industry today, they submit that these controller types produce emissions that the industry can eliminate. Simply put, the commenter contends that there is little need for these controller types when a feasible, cost-effective alternative with no bleeding is available. The commenter reports that they have developed multiple configurations to cover the spectrum of possible well-pad pneumatic emissions, spanning from a minimum of one small “CAP3-nano” providing 1 scfm to a single pad in a low-bleed site up to a double “CAP3-M” providing<sup>14</sup> 24 scfm to a 16-well pad. The commenter provides that their different CAP3 configurations are presented in Appendices D and E of their comment letter (which contain CBI). The commenter concludes that they maintain that there are no specific functional needs that require a low-bleed or intermittent controller that vents natural gas into the atmosphere.

The commenter (0823-Qnergy) suggests that EPA regulations recognize in the BSER and standards of performance the role of innovative technologies such as their CAP3 technology, which they contend virtually eliminates methane emissions from pneumatic devices and provides system monitoring to ensure effective and continuous emission control. The commenter submits to EPA that the CAP3 system’s performance can raise the bar for pneumatic controllers and pumps. They assert that it can serve as a basis for the BSER, as demonstrated by an increasing reliance by leading companies in the industry<sup>15</sup> because of CAP3’s elimination of methane emissions, commercial availability, lowest possible abatement costs and overall environmental

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generation, which EPA recognizes as only “secondary impacts from the use of instrument air systems” that still allow pneumatic devices to meet the proposed emission rate of zero. 2021 November Proposed Rule at 63208.

<sup>12</sup> See Appendix A of the commenter’s letter submission for more information about their (Qnergy’s) technology and its uses and Appendix E of the commenter’s letter submission for their internal abatement cost data. Appendix E of the commenter’s letter contains Confidential Business Information (CBI).

<sup>13</sup> The commenter (Qnergy) states they close \$16 million series C funding round, led by OGCI Climate investments, QENERGY (Nov. 16, 2021), <https://www.qnergy.com/qnergy-closes-16-million-series-c-funding-round-led-by-ogci-climate-investments/>.

<sup>14</sup> Proposed Rule at 63179, 63207

<sup>15</sup> The commenter states that their technology is well known, and accepted, throughout the industry. Over 80 customers—including regional, national, and global natural gas leaders—have chosen to use the commenter’s (Qnergy) technology in the field to reduce emissions. Appendix B (of the commenter’s letter) provides a partial list of active users among U.S. natural gas producers. Additional users can be found in an attachment to the commenter’s letter (Appendix D of the commenter’s letter). All of these materials contain CBI

performance (e.g., lower CO<sub>2</sub> equivalent emissions and only negligible emissions of non-greenhouse gases (GHGs) or VOCs).<sup>16</sup>

Response I-10-15: The EPA acknowledges that a compressed air system using a generator is one available method through which zero emissions from process controllers may be attained. See section IV.D of the December 2022 Supplemental Proposal (87 FR 74755-74769) for references to the use of compressed air or instrument air systems along with generators to meet a zero-emissions requirement.

Comment: Commenter (0844-EDF *et al.*) states that when electricity is not available to power electronic or instrument air controllers, nitrogen provides a feasible zero-emission alternative to operating pneumatic devices. The commenter explains that, unlike instrument air systems that require electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, which is replaced or refilled periodically, and a liquid nitrogen vaporizer.<sup>17</sup> The commenter reports that one company in British Columbia, Kathairos, provides a service that allows operators to store a quantity of liquid nitrogen at a site, which (after on-site gasification) provides a source of dry nitrogen gas to drive pneumatics instead of using natural gas.<sup>18</sup> According to the commenter, the system requires no electricity or on-site power generation.<sup>19</sup> The commenter also states that Instrument air devices can also be powered by solar generators. There are several manufacturers advancing this technology.<sup>20</sup>

Response I-10-16: Although the EPA did not specifically include the use of nitrogen canisters as a zero-emissions option in our BSER analyses due to a lack of nationwide availability, we acknowledge that it is a technically feasible option and may be cost-effective for some sites to use for powering pneumatic process controllers.

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<sup>16</sup> Appendices C, D, and E of the commenter's letter contain more CBI based on the commenter's internal testing and data collection efforts.

<sup>17</sup> EPA, Lessons Learned: Natural Gas STAR Partners, Options for Reducing Methane Emissions from Pneumatic Devices in The Natural Gas Industry, (Oct. 2006), available at [https://www.epa.gov/sites/default/files/2016-06/documents/ll\\_pneumatics.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/ll_pneumatics.pdf)

<sup>18</sup> Petroleum Alliance Technology Canada, PTAC TIS: Kathairos Introduces Novel Solution Using Liquid Nitrogen to Produce Zero Methane Emission Result <https://www.ptac.org/events/ptac-tis-kathairos-introduces-novel-solution-using-liquid-nitrogen-to-produce-zero-methane-emission-result/> (last visited Jan. 27, 2022); See also Petroleum Alliance Technology Canada, Kathairos Introduces Novel Solution Using Liquid Nitrogen to Produce Zero Methane Emission Result (Dec. 2020), [https://www.ptac.org/wp-content/uploads/2020/12/PTAC-TIS\\_-Kathairos-Introduces-Novel-Solution-Using-LiquidNitrogen-to-Produce-Zero-Methane-Emission-Result-1.pdf](https://www.ptac.org/wp-content/uploads/2020/12/PTAC-TIS_-Kathairos-Introduces-Novel-Solution-Using-LiquidNitrogen-to-Produce-Zero-Methane-Emission-Result-1.pdf)

<sup>19</sup> Comment submitted by Kathairos Solutions Inc. Posted Dec 16, 2021. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0384>

<sup>20</sup> Carbon Limits 2021 at 7-8. A new technology package called the Aurora Eco-System, offered by Air Works Compressors, provides an instrument air system powered by solar PV or wind power installed at the well-sites. As of mid-2021, the solar-powered Aurora Eco-System package has been installed in 22 sites in Alberta, Wyoming, Utah, and Peru. 2021. Carbon Limits 2021 at 7. Additionally, LCO technology markets the Crossfire Instrument Air Compressor (see <https://lco-technologies.com/crossfire-compressor.html>) and WestGen Technology markets the Engineered Power on Demand (EPOD) unit to provide sites with both compressed air and electricity. The unit derives most of its power from solar panels but supplements the solar with a small gas-driven engine (needed particularly in Canadian winters) (see <https://westgentech.com/epod-ap-series/>). Other examples include Alert Control Technologies, <https://alertcontrol.com/air-compressors/> (last visited Jan. 27, 2022); and Axiom Technologies LLC, <https://axiomsafety.com/solar-powered-air-compressors/> (last visited Jan. 27, 2022).

### ***10.3.5 Technical Limitations of Electrically Actuated Controllers***

Comment: Commenters note that there are technical limitations with electrically actuated controllers. Commenter (0743-WEA) states that electric controllers can generally only be used to control valves so their use will not be sufficient to reliably keep an entire facility operating safely.

Commenter (0817-GPA) notes that electrically actuated valves do not have the speed and performance of gas-powered actuators (including air-powered actuators), limiting their utility. In particular, the commenter states they have a higher failure rate than gas-powered actuators, especially for throttle service where the actuator is constantly adjusting based on process conditions, instead of a set point. The commenter adds that the controllers are more expensive and there are few options available on the market which would drive up prices further in the case of any mandate. Also, the commenter states that electrically actuated controllers require the installation of a complex automated control system. The commenter asserts that neither of these additional costs appear to have been included in EPA's estimates.

Commenters (0743-WEA, 0817-GPA) state that back-up systems such as instrument air would likely be required to operate facilities safely. For remote sites where electricity is not available, installation of a generator to supply power for instrument air and/or electric controllers would be necessary, which would cause an offset of the already very low emissions reductions as well as incur additional cost that was not included in EPA's analysis.

Response I-10-17: There are many options available to owner/operators for compliance with the process controller standards. If an owner/operator is concerned about using electric process controllers, other options include using a compressed air system to power pneumatic process controllers, using self-contained process controllers, or routing process controller emissions to a process. For discussion of secondary emissions from process controllers powered by generators, see section IV.D.1.b.iii. of the December 2022 Supplemental Proposal preamble (87 FR 74765) and section XI. D.2 of the preamble to the final rule. For the model plant scenarios evaluated in the BSER analysis and the costs of zero-emissions technologies, including the use of generators and electric process controllers, see section XI.D.1 of the preamble to the final rule.

## **10.4 Access to Electrical Grid**

Comment: Commenter (0808-API) requests that EPA clarify that "access to power" means that commercial line power is available onsite, sufficient to cover the power/capacity requirements of the non-emitting pneumatic controller design of the facility, and which provides reliable and consistent coverage. The commenter goes on to highlight technical challenges with grid power requirements. Specifically, the commenter requests that EPA consider the following aspects of grid power:

- Access to Grid Power. Access to grid power must be limited to commercially available onsite connections with sufficient and reliable power. It is not always logistically feasible to electrify a location from the grid due to issues outside of an owner/operator's control. These challenges include right-of-way (ROW) issues for placement of power lines, a landowner's

right to not install power lines on their property]<sup>21</sup>, and/or distance from an available power line that contains sufficient power and capacity to connect the facility. Therefore, EPA must be clear that running new commercial power lines to any site is not EPA's intent given the practical, technical, and cost challenges this would cause at large scale implementation across the country.

- Sufficient Volume and Quality of Grid Power. Equipment power requirements at oil and gas facilities are quite varied, ranging from instrumentation at a single well pad needing approximately 35 watts to operate all the way up to approximately 2,000 kilowatts at larger sites running more equipment on electrical power. The power demand required to operate equipment determines if single phase power (household) is adequate or if three phase power (industrial) is necessary. Single phase low volume power may be accessible in certain areas, but three phase industrial wattage levels may not be available. Furthermore, even with accessibility, there may not be sufficient levels to run a given site or field. Due to the challenges around the development of adequate power supply to remote locations and the temporary nature of some areas of oilfield demand, many sites are supplied by onsite generation through produced natural gas as a motive source or natural gas generators.
- Right-of-Way Issues. The largest challenge to oil and gas operations having grid power is obtaining ROW access for power lines. On private lands, landowners may choose to never allow ROW, particularly on large ranches. On federal lands, the current lead time for installation is typically between 6 months up to 2 years. It should be noted that the longest lead times have been experienced on federal lands controlled under the Bureau of Land Management (BLM). Additionally, as the Administration pursues updates to other regulatory requirements, such as environmental reviews as proposed by the Council on Environmental Quality in the Phase 1 National Environmental Policy Act (NEPA) revisions, these challenges may be exacerbated by expanding requirements and protracted timelines. A Memorandum of Understanding (MOU) may be needed between EPA and BLM and state land offices to expedite approval of ROW for grid power.

The commenter (0808-API) states that even if logistically possible, it is unlikely to be cost-effective to access off-site grid power to convert a site to non-emitting controllers. According to the commenter, even without the foregoing concerns, the cost and timing to obtain grid access can be prohibitive when it is not readily accessible onsite.

As a point of reference, the commenter (0808-API) states that experiences with their member companies suggest an average estimated cost of approximately \$200,000 per mile for installing an electrical line to a facility where one does not already exist. When this additional cost is considered for 1 mile of new power line and all other EPA assumptions remain, the commenter states that the retrofit of pneumatic controllers is not cost-effective for small and medium model plants. The commenter notes that, since EPA did not include nor consider costs for installing new power lines in its cost benefit analysis, it is assumed EPA did not intend to require operators to run new commercial power lines in order meet proposed control requirements for pneumatic controllers. The commenter notes that they support EPA in this approach, as this would not be

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<sup>21</sup> According to the commenter, in some states, the utility provider can implement eminent domain, but production companies would not and do not have this authority. Other states, such as North Dakota, do not have eminent domain authority.

cost-effective and would cause other environmental disbenefits (*e.g.*, potential land disturbance) in pursuit of eliminating emissions from a small number of ancillary controllers.

Another commenter (0831-AXPC) states that they believe it is important that the supplemental proposal specify that it is not the agency's intent to require operators to run new commercial power lines, certainly in situations where it would be practically, technically, or economically infeasible to do so.

Response I-10-18: In the NSPS and EG regulatory language for the December 2022 Supplemental Proposal and the final rule, the definition for "Access to electrical power" is that commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power. See NSPS §60.5430b and EG §60.5430c. The EPA is not requiring and does not expect sites to extend grid power lines to their sites for compliance with the NSPS or EG. See section XI.D.3 of the final rule preamble for further discussion of the BSER for sites without access to electrical power.

Comment: Commenters (0817-GPA, 0938-TXOGA) request that EPA subcategorize existing facilities with and without access to supplied power and then determine BSER separately for each subcategory. Commenter (0938-TXOGA) notes that the availability of electricity is a significant and constraining factor that is within EPA's authority to consider in subcategorization. Commenter (0817-GPA) states that it would also be important to establish that any supplied power is sufficient to support the additional equipment needed to comply with the rule. According to the commenter (0817-GPA), if no provision is given for available supplied power, additional combustion sources would need to be installed to provide it. They add that generators would likely be rented until a permanent power source is constructed which would result in additional costs not considered by EPA as well as increased generator combustion emissions.

Commenter (0803-Ohio Oil and Gas Association (OOGA)) states that their members' operations are located predominantly in rural locations and access to connect to the electric grid is not always readily available. They add that obtaining access to the grid can take several months to years to coordinate with property owners (easements), electric utility providers, and environmental agencies to receive approval installation of new electric lines. Once approval is received it can take several more months to complete construction. Further, the commenter states that much of the timing of this process is out of the hands of the commenter's members. The commenter notes that it is a very large project and EPA has not considered the entire scope much less the timing.

Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) states that the use of electrical controllers assumes access to the electrical grid, and this may not be the case for all sites, particularly in the Permian Basin, Eagle Ford Shale, or other similarly rural exploration fields.

Commenter (0823-Qnergy) states that because they have demonstrated that it is technically feasible to require the use of zero-emissions pneumatic controller at facilities with or without access to electric or solar power, it requests that EPA base its BSER on the understanding that

any facilities with access to electric or solar power incorporate zero-emissions pneumatic controllers.

Commenter (0844-EDF *et al.*) reports that a significant number of sites already have access to the grid, and an even larger number can connect a line to the grid. According to EPA's assumptions, all processing plants and 40 percent of well sites have access to reliable electricity. The commenter adds that, in a 2015 survey of companies<sup>22</sup>, 34 percent of companies in the U.S. reported that all of their gathering compressor stations have grid access and only 7 percent reported that none of their sites had access, with grid accessibility having likely improved across the industry since 2015.

The commenter (0844-EDF *et al.*) adds that, at sites without grid access, electronic controllers can be powered by solar control systems. The commenter states that these systems are approximately as cost-effective as grid-powered electric controllers and are technologically feasible for both new sites and retrofitting existing sites.<sup>23</sup> The commenter further indicates that the solar resource is sufficient to power these systems in many geographic locations. Consider, for instance, northern Alberta, where substantial oil and gas development occurs: solar panels generate less power than in lower latitudes, sunlight on a clear day is far weaker than in many parts of the U.S., snowfall is higher and winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). Nevertheless, the commenter asserts that solar-powered controllers have been reliable for oil and gas companies operating there.<sup>24</sup> The commenter reports that Calscan, an Alberta vendor of packages that utilize solar-power and batteries to power electric actuators and instrumentation for zero-emission separators,<sup>25</sup> estimates that they have sold about four hundred of these packages in Canada (mainly in Alberta).<sup>26</sup> Moreover, Energy Information Administration (EIA) data demonstrates that the availability of solar power in several regions around the U.S. has increased significantly over the past five years.<sup>27</sup> In addition, the commenter notes that, although solar technology has been most commonly used at small and medium sites in the past, it is now available and cost-effective at larger sites due to the falling prices of photovoltaic (PV) panels and battery systems, improvements in PV output, and the ease of installing solar PV systems. Furthermore, the commenter notes that operators have found that reliability has increased when using additional, vertically stacked solar panels<sup>28</sup> or an additional methanol fuel cell.<sup>29</sup>

Commenter (1391-INGAA) suggests that the exemption available for sites in Alaska should apply throughout the entire U.S. for sites where there is no available electric power. The

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<sup>22</sup> Alphabet Energy, On-Site Power: New Options for Wellhead & Gathering Compression, Natural Gas Star Annual Implementation Workshop, November 18, 2015, <https://www.epa.gov/sites/default/files/2016-04/documents/16hjalmarsonpahl.pdf> (last accessed January 21, 2022)

<sup>23</sup> WZI 2021 at 1-2.

<sup>24</sup> Colorado Air Pollution Control Division, Pneumatic Controller Task Force Report 37 (June 2020).

<sup>25</sup> See Calscan Solutions, Zero GHG Venting Controls for Separators, [http://www.calscan.net/solutions\\_ZeroGHGVenting.html](http://www.calscan.net/solutions_ZeroGHGVenting.html) (last visited Jan. 27, 2022).

<sup>26</sup> David McCabe Conversation with Henri Tessier, Calscan (Oct. 30, 2020).

<sup>27</sup> Attachment S to the commenter's provided public comment submission, EIA Solar Capacity and Generation by Region and Year

<sup>28</sup> Carbon Limits 2021 at 5-6.

<sup>29</sup> Carbon Limits 2021 at 6.

commenter contends that it is arbitrary and capricious that the exemption that applies within Alaska would not also apply to areas in the other 49 states where the same situation exists. The commenter cites as an example that several of their members operate pipelines in a very remote part of a state forest in Pennsylvania and other states where electric power is unavailable.<sup>30</sup> According to the commenter, installation of an electric transmission line is not feasible given the distance to the site and because of the forest (*i.e.*, a large amount of state forest would need to be cleared to install the panels and it is unclear that the state would allow this). The commenter adds that, at a different location in Pennsylvania, some of the metering stations could have power installed to them without too much issue. However, in some instances, electrical lines over 10 miles long in remote areas would need to be installed. The commenter continues by citing problems with solar power (discussed elsewhere in this Chapter). The commenter adds that another member in Texas operates a pipeline on land where the landowner is not welcoming to any future development. The commenter's member has attempted for years to add power to the site, but all efforts have failed. Although the commenter's member was able to borrow a spare circuit from an adjacent transmission operator and run it a couple of hundred feet into the fence, that circuit only provides enough power to run some low-power equipment. The commenter states that the site has nothing close to the power needed to run electric actuators or air compression. They add that there is not enough space to install a solar panel system that would be sizeable enough and that would still have the reliability issues. The commenter contends that these types of landowner issues can make safe and reliable operation almost impossible without the use of gas-driven equipment.

Commenter (0740-UPA) states that EPA has underestimated the costs of electrifying Utah oil and gas operations. As a result, they request that EPA provide an exemption from zero-emission pneumatic controllers in Utah at non-electrified sites, similar to the exemption that EPA proposed to provide for operations in Alaska that lack power.<sup>31</sup>

Response I-10-19: The EPA has determined that the BSER is zero emissions from process controllers except at sites in Alaska without access to electrical power. See discussion in section IV.D.1.b.iii. of the December 2022 Supplemental Proposal preamble (87 FR 74764-74765) and section XI. D.3 of the preamble to the final rule.

## **10.5 Use of Generators at Sites without Electricity**

Comment: Several commenters (0749-PAW, 0808-API, 0831-AXPC) indicate that at sites without electricity, owners or operators would likely install a generator to power an instrument air system. These commenters contended that relying on a generator would result in emissions of criteria pollutants and carbon monoxide (CO) that could potentially offset the emissions reductions from the methane and VOC. One commenter (AXPC) provided an estimate that a natural gas-fired generator of approximately 200 horsepower would be needed to support reliable operation of a large instrument air system without grid power. This commenter estimated emissions from a generator that size to be 1.94 tons per year (tpy) nitrogen oxide (NO<sub>x</sub>), 3.88 tpy

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<sup>30</sup> The commenter reports that pipelines being in forest land is not unusual. Installation of electric power lines or solar panels on forest land will involve the clearing of acres of forest that may not be permitted by the applicable forest authority.

<sup>31</sup> See November 2021 Proposal, 86 FR 63179 and 63189.



of CO, 1.36 tpy of VOC, 0.12 tpy of particulate meter with a diameter of 10 micrometers or less (PM<sub>10</sub>), 0.14 tpy CH<sub>4</sub> and 730 tpy of CO<sub>2</sub>. Still, to achieve the large-scale deployment of non-emitting pneumatic devices that the November 2021 Proposal envisions the commenter asks EPA to account for these circumstances where an operator cannot obtain grid power (whether for legal or practical reasons), where there are delays in building grid connections, or where renewables may not be a reliable or feasible option and allow for the use of natural gas or diesel generators as the most feasible option to achieve a non-emitting control standard.

Response I-10-20: See discussion of secondary emissions from process controllers powered by generators in section IV.D.1.b.iii. of the December 2022 Supplemental Proposal preamble (87 FR 74765) and section XI. D.2 of the preamble to the final rule. The final rule is technology-neutral and does not require the use of grid power to attain zero emissions from process controllers. See section XI.D.3 of the preamble to the final rule for further discussion of the BSER and the NSPS and EG requirements for process controllers.

Comment: Commenter (0823-Qnergy) states that internal combustion engine (ICE) generators typically are cheaper to purchase than lower emitting generators, and so some owners and operators may be inclined to purchase them to power pneumatic devices. However, the commenter notes that ICE generators require higher maintenance costs compared to their company's technologies. The commenter supports EPA's November 2021 Proposal for BSER and corresponding standards of performance to prohibit the use of such generators, as they are not only unnecessary, but would contravene the emissions reductions the Proposed Rule seeks to implement. By adopting technology like CAP3 [their technology], they contend that oil and gas owners and operators can minimize overall emissions and completely eliminate methane and VOC emissions from pneumatic devices, at a lower total cost of ownership. The commenter requests that the forthcoming rule expressly recognize this and prohibit the use of ICE-powered generators as a power source for pneumatic devices. The commenter notes that their technology achieves demonstrable emissions reductions for pneumatic devices at the lowest abatement cost in the industry, and they believe it should form the basis for EPA's BSER and performance standards for pneumatic controllers and pumps. Upon EPA's request, the commenter states that they are willing to share confidential pricing information with the Agency as well as anonymized user data and benchmarks on air consumption across the industry. The commenter appreciates EPA's attention and welcomes the opportunity for further dialogue regarding their technology and the ways it can promote the important statutory goals EPA seeks to fulfill with this rulemaking.

Response I-10-21: The EPA is not prohibiting the use of ICE-powered generators as a power source for process controllers. As explained in section XI.D.2 of the preamble to the final rule, the EPA's emissions standards are technology-neutral. For discussion of the secondary emissions from process controllers powered by generators, see section IV.D.1.b.iii. of the December 2022 Supplemental Proposal preamble (87 FR 74765) and section XI. D.2 of the preamble to the final rule.

Comment: Commenter (0844-EDF *et al.*) states that some sites without a grid connection may choose to use an on-site generator to power electronic controllers. The commenter provides that this technology is readily available, and many sites already have power generation on-site for

other purposes like lighting, automation, and control systems. The commenter is confident that despite secondary impacts, this option is also environmentally beneficial. The commenter notes that generator-run instrument air can produce NO<sub>x</sub> emissions, but the pollution benefits of using this technology far outweigh the harm from those emissions. The commenter reports that one analysis obtained emissions data from two vendors that supply engine/air compressor packages and found that these types of compressed air packages will prevent at least ninety times more VOC emissions (by weight) than the NO<sub>x</sub> emissions they produce.<sup>32</sup> Beyond natural gas generators, the commenter reports that there are also thermoelectric generators that can convert waste heat in compressor exhaust to electricity.<sup>33</sup> The commenter continues that electronic controllers can also be powered by a hybrid system of solar and gas-fired generation. Prefabricated units are available, and operators can choose between backup power systems using a genset or battery storage depending on cost, available space, and other factors.<sup>34</sup>

Response I-10-22: See Volume II, Chapter 7 (Process Controllers), subsection 7.2.5 (Generators), Response II-7-39, for a summary of EPA's analysis of the secondary emissions that would be created by the use of generators. The secondary emissions that would occur are estimated to be relatively small and are outweighed by the emissions reductions that would be reduced from the process controllers.

## 10.6 Electronic Controllers

Comment: Commenter (0844-EDF *et al.*) states that zero-emitting electronic controllers are readily available and are engineered by a variety of companies, and the technology continues to advance. The commenter reports that one company has installed over 1800 electric actuators at oil and gas sites throughout Western Canada over the past seven years and plans on installing over 1,000 in 2022.<sup>35</sup> The commenter adds that electronic controllers are highly cost-effective, reducing methane at an expense that is far lower than levels that EPA has in the past found were cost-effective.<sup>36</sup> Additionally, the power required for electronic controllers is decreasing. In fact, the commenter states that power demand for electronic controllers is lower than for traditional gas-driven controllers.<sup>37</sup> Furthermore, the commenter notes that electronic systems have much lower maintenance costs than gas-driven controller systems and are longer lasting,<sup>38</sup> and electronic controllers and actuators can be connected to existing valves at well sites, eliminating the need to replace control valves.<sup>39</sup>

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<sup>32</sup> CATF, Comparison of NO<sub>x</sub> emissions to avoided VOC emissions for Colorado usage of commercially available compressed air packages (Jan. 2021).

<sup>33</sup> GTI, Developing an Integrated Thermoelectric System to Mitigate Methane Emissions Effectively, <https://www.gti.energy/developing-an-integrated-thermoelectric-system-to-mitigate-methane-emissions-effectively/> (last retrieved Jan. 27, 2022).

<sup>34</sup> WZI at 6.

<sup>35</sup> Tressier, Henri, Managing Partner, Calscan Solutions, Email to Grace Smith, Environmental Defense Fund, January 26, 2022

<sup>36</sup> See *supra* Figure 23; See 86 Fed. Reg. 63110, 63,155 (Nov. 15, 2021) ("EPA finds the cost-effectiveness values up to \$1,800/ton of methane reduction to be reasonable").

<sup>37</sup> WZI, Inc., Review of Oil and Gas Facility Controller Deployment Alternatives in Colorado (Jan. 2021) ("WZI 2021") at 7.

<sup>38</sup> WZI 2021 at 7.

<sup>39</sup> Carbon Limits 2021 at 9.

Response I-10-23: The EPA appreciates the commenter's provided information. This and other comments received regarding zero-emitting technologies were considered when developing the NSPS OOOOb and EG OOOOc final rule requirements. See section X.D (Process Controllers) of the final rule preamble for a summary of the final process controller NSPS OOOOb and EG OOOOc requirements.

## **10.7 Low and Intermittent Bleed Pneumatic Controllers**

Comment: Commenter (0749-PAW) states that EPA should propose a rule that allows for low or intermittent bleed devices to be used for existing facilities. The commenter explains that, for smaller facilities that have lower production, installing and operating instrument air systems could easily exceed the value of the recoverable production from the wells associated with those facilities, forcing those operators to shut in production. Across the U.S there are thousands of wells that, according to the commenter, would be rendered uneconomic to operate should the framework described in EPA's publication be proposed for existing sources.

Another commenter (0802-Kraken Oil & Gas LLC (Kraken)) urges EPA to allow low and intermittent bleed pneumatic controllers to be used for all new and existing facilities and that retrofitting any pneumatic controllers already compliant with NSPS OOOO/OOOOa is not warranted. The commenter notes that they support reducing emissions from pneumatic controllers, and it is why they have always used intermittent bleed and low bleed pneumatic controllers with bleed rates lower than the requirement set forth in NSPS OOOO/OOOOa, to (less than 6 standard cubic feet (scf)/hour). The commenter states that their operations employ pneumatic controllers with bleed rates well under 1 scf/hour, and some as low as 0.03 scf/hour. Further, the commenter explains that the intermittent bleed and low bleed pneumatic controllers are designed to be tough for operating in the harsh weather and temperature conditions can often result in interrupted electricity delivery or redirected power demands. The commenter indicates that since their facilities are generally unmanned, the controllers need to be reliable and reconfiguring these controllers to operate using electricity and instrument air introduces increased reliability issues.

Commenter (0808-API) recommends that, absent feasibility to retrofit, the use of continuous low bleed and intermittent natural gas controllers at existing facilities be allowed and covered in an operator's existing LDAR monitoring program to monitor proper functioning. The commenter cites potential site physical constraints for small sites and notes that retrofit costs would be prohibitive for low-producing wells which could cause low-production or stripper wells to be forced to shut down. The commenter explains that existing well pads may have sizing constraints for the proper placement (due to safety and other permitting constraints) of control systems and compressors that must sit outside of classified areas, generators, or solar panels. Further, the commenter notes that the state regulations that EPA cites in support of the November 2021 Proposal, including Colorado and the current proposed version of regulations pending in New Mexico<sup>40</sup>, do not require all existing controllers to be retrofitted. The commenter states that

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<sup>40</sup> <https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf>

Colorado's regulations, as well as the draft regulations pending in New Mexico, concluded this is unwarranted as controller retrofit is not cost-effective nor technically feasible for many facilities.

Response I-10-24: Similar comments were made on the December 2022 Supplemental Proposal, see response in Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), Response II-7-79.

Comment: Commenters (0810-Petroleum Alliance-OK, 0814-Independent Petroleum Association of America (IPAA) *et al.*) state that the low emissions of backpressure intermittent controllers do not justify regulation. The commenters note that a 2014 study they conducted found that intermittent vent controllers emitted on the average 0.047 tons/year of methane. A comparison of these results with the existing body of work on emissions from these types of controllers found that the other studies overestimated emissions by a factor ranging from 5.4 to 27.5. The study showed that 17 of 77 controller models identified were backpressure controllers (accounting for approximately 40 percent of controllers observed) and that these controllers are often used for overpressure protection that rarely actuated when encountered during field observations. The commenter contends that this information indicates that normally functioning intermittent pneumatic controllers are not an issue and should not be regulated. According to the commenter, it is not reasonable, cost-effective, or efficient for operators, especially marginal/low production well operators, to now replace well-functioning intermittent vent controllers or retrofit their sites to use air-driven, solar, electric, or self-contained controllers.

Response I-10-25: Similar comments were made on the December 2022 Supplemental Proposal, see response in Volume II, Chapter 7 (Process Controllers), subsection 7.3.1 (Emissions/Emission Factors), Response II-7-62.

Comment: Commenter (0787/1289-Atmos Energy Corporation (Atmos)) suggests that EPA further consider subcategorizing low-emitting pneumatic controllers, which are predominantly used in the transmission and storage segment. The commenter notes that in the November 2021 Proposal TSD, EPA presents intermittent vent devices in the transmission and storage segment as making up approximately 2 percent of the methane emissions from pneumatic controllers and approximately 0.03 percent of total methane emissions from the transmission and storage segment.<sup>41</sup> The commenter suggests that EPA allow companies to demonstrate that a site's potential emissions fall within the low-emitting subcategory. They suggest that the demonstration could include submission of actual equipment design parameters (*e.g.*, bleed rate per stroke), maximum actual operations (*i.e.*, maximum anticipated strokes per year for intermittent devices), and the presumption of proper operation.<sup>42</sup> According to the commenter, implementing these options, or a similar approach, would be consistent with EPA's stated purpose. of "limiting super-emitters through actions included in this rule such as reducing fugitive emissions, using lower-emitting equipment where feasible [emphasis added], and

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<sup>41</sup> TSD at Table 8-2. [23] Id. at 8-27.

<sup>42</sup> The commenter states that EPA should not use 40 C.F.R. 98 Subpart W average emission factors for pneumatic controllers for such a demonstration, because it would be less accurate and, thus, defeat the purpose of creating the subcategory.

employing best management practices [to] not only reduce emissions but to reduce the loss and revenue from this valuable commodity.”<sup>43</sup>

Commenter (0787-Atmos) alternatively suggests that EPA consider subcategorizing natural gas pneumatic controllers for the transmission and storage segment and require that natural gas intermittent vent controllers at small sites be monitored with enhanced maintenance.

Response I-10-26: Similar comments were made on the December 2022 Supplemental Proposal. See response in Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), Response II-7-79.

Comment: Commenters (0793-PBPA, 0808-API) urge EPA to provide flexibility to use low-bleed controllers where electricity is not available. The commenters note that, as EPA has recognized, low-bleed controllers reduce emissions by a substantial 84 percent compared to high-bleed devices in the production sector. The commenters request that, as EPA has proposed to allow only sources located in Alaska that lack onsite power to use low-bleed controllers, EPA extend the flexibility to use low-bleed controllers to all sources.

Commenter (0808-API) adds that they support EPA’s November 2021 Proposal to retrofit to non-emitting controllers, where the following criteria are met: a) there are at least 15 controllers at the well site, central production facility, or compressor station; and b) there is access to sufficient and reliable grid power onsite. If the above criteria are not met, then any high-bleed natural gas-driven controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company’s LDAR monitoring program to monitor proper functioning. The commenter notes that this approach is similar to and based on the rationale for EPA’s proposed requirements for pneumatic controllers at sites in Alaska without grid access.

Another commenter (1341-Conventional Groups) states that EPA's evaluation provided that “electrical supply is assumed to be on site irrespective of the electronic controllers at the site” and the “costs of the power supply were not included in the analyses of emission reductions and the costs for electronic controllers.” November 2021 Proposal TSD, p. 8-21. The commenter provides that, without a reliable electrical source to convert to instrument air, the only other potential compliance option would be retrofitting existing natural gas-driven controllers with low-bleed controllers. The commenter contends that the capital costs and maintenance costs of even one controller would be unreasonable, for marginal, if any, environmental benefit.

Response I-10-27: The NSPS and EG are required by the CAA to be based on the BSER. In the revised BSER analysis conducted for the December 2022 Supplemental Proposal and in the refreshed analysis conducted for the final rule, zero emissions from process controllers was shown to be technically achievable and cost-effective at all model plant configurations (outside of Alaska) through several available options. As such, the EPA determined that zero emissions represents the BSER and is the basis for the requirements of the NSPS and EG. For further details regarding the revised BSER analyses, see sections IV.D.1.b. ii and iii of the December

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<sup>43</sup> 86 Fed. Reg. at 63,130 (emphasis added)

2022 Supplemental Proposal preamble (87 FR 74760-74766) and sections XI. D.2 and 3 of the preamble to the final rule.

Comment: Commenter (0808-API) suggests that EPA exempt facilities from the non-emitting controller standard under NSPS OOOOb and EG OOOOc if there is only a single low bleed or intermittent controller present. The commenter provides a cost-effectiveness analysis which indicates that methane costs range from \$7,000 to \$73,000 per ton of methane reduced for single low bleed and intermittent controllers. According to the commenter, the results indicate it is not cost-effective to retrofit a single low bleed or intermittent controller. The commenter notes that this analysis relied on controller system costs as provided in EPA's pneumatic controllers costs and emissions workbook for a small model plant. The commenter reports that their survey suggests minimum costs are at least double the costs estimated by EPA for small model plants, which would best reflect the minimum costs associated with retrofitting a single controller.

Response I-10-28: In the BSER analysis conducted for the final rule, the EPA found there are zero-emissions process controller options with costs that are reasonable, considering the emissions reductions that would be achieved, for all model plants studied. The smallest model plant evaluated included four process controllers. For further details regarding the revised BSER analyses, see sections IV.D.1.b. ii and iii of the December 2022 Supplemental Proposal preamble (87 FR 74760-74766) and sections XI. D.2 and 3 of the preamble to the final rule.

Comment: Commenter (0844-EDF *et al.*) provides that numerous studies indicate that pneumatic controllers often emit more than their design values indicate. They add that intermittent controllers are designed to emit only during the actuation cycle for the controller, but in the field, these devices frequently emit between actuations. For example, the commenter states that Luck *et al.* (2019) reported that 63 percent of the intermittent controllers observed as part of that study were operating abnormally.<sup>44</sup> Similarly, the commenter states that “low-bleed” continuous pneumatic controllers have also been observed to frequently emit more than they are designed to emit, and it is not uncommon for their emissions to exceed the 6 standard cubic feet per hour standard for “low-bleed” devices. Due to the ubiquity of these types of malfunctions, the commenter states that measures designed to merely reduce emissions from pneumatic controllers (such as by requiring that any continuous controller be “low-bleed”) have generally proved to be less effective than anticipated. For this reason, the commenter believes that EPA's November 2021 proposed approach to require all devices to be non-emitting is appropriate.

Response I-10-29: This comment is a supportive comment on an aspect of the November 2021 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

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<sup>44</sup> Benjamin Luck et al., Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations, *Environ. Sci. Technol. Letters* 6, 348 52 (2019), <https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158>.

## 10.8 Exceptions and Exemptions

### 10.8.1 Functional Need Exemption

#### 10.8.1.1 Opposition to Exemption

Comment: Commenter (0844-EDF *et al.*) recommends that EPA eliminate its November 2021 proposed functional need exemption at processing plants. The commenter states that, if the agency determines it must finalize a functional need exemption for processing plants, it must narrowly tailor the accommodation. The commenter explains that the exemption as proposed in November 2021 would not require processing plant operators to pursue other technologies that would reduce emissions if non-emitting technologies are not feasible. They recommend that EPA require any such operators to first attempt to reduce emissions by at least 95 percent,<sup>45</sup> with a preference for routing to a process rather than a control device. If that target is still not feasible, operators should then reduce emissions to the greatest extent possible. In these instances, operators should be required to provide a functional need justification in their annual report, including documentation as to: (1) why power (either grid-based or solar) is unavailable, (2) where the operator isn't routing to a process or control device or achieving 95 percent reductions, why they are not doing so, and (3) how the operator plans to minimize emissions from their pneumatic controllers to the maximum extent possible. The commenter suggests that, in any instances where operators utilize continuous-bleed or intermittent-bleed controllers, they should, at a bare minimum, be required to comply with the finalized recordkeeping and LDAR standards recommended in Part IV.A of their comments.

Several other commenters (0391-KBIC, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0815-AGA, 0833-Ute EPD, 0943-Sault EPD) express that they support removal of the functional needs exemption for all segments of the oil and natural gas sector including pneumatic controllers in Alaska.

Response I-10-30: See discussion in section IV.D.1.b.i of the December 2022 Supplemental Proposal (87 FR 74759) for response to comments regarding the functional needs exemption.

#### 10.8.1.2 Support for Exemption

##### *Functional Needs/Technical Infeasibility Assessment*

Comment: Several commenters (0599-MSA, 0787/1289-Atmos, 0808-API, 0815-AGA, 0831-AXPC, 1391-INGAA) request that the NSPS OOOOa functional needs exemptions be included in NSPS OOOOb in their entirety based on several reasons, primarily based on concerns about the suitability, reliability, availability and technical feasibility of application (*i.e.*, response time, safety, and positive actuation) of zero-emitting technologies at all sites in the oil and natural gas sector. Commenter (0787/1289-Atmos) states that EPA's belief that "the reasons [for the functional needs exemption] related to the use of low bleed controllers" are no longer applicable

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<sup>45</sup> For example, the commenter states that operators that can't install zero-emitting technology might nonetheless be able to route to a vapor recovery unit or control device, which aren't zero-emitting in accordance with the proposed standard, but which reduce emissions by 95-98 percent. See November 2021 Proposal TSD 6-16: TSD 9-9.

is premature for at least three reasons. First, the commenter notes that EPA's own field experience has shown that only up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted.<sup>46</sup> Second, the commenter states that electrical supply is not available at every site.<sup>47</sup> Depending upon the location of the site, the commenter notes that the cost of establishing electrical service can far outweigh the cost of installing an electronic controller or compressed air system.<sup>48</sup> Third, the commenter notes that electricity-driven devices may not be suitable for all functions and operating conditions. Natural gas pneumatic controllers can place a valve in a closed, open, or specific position in the event of failure; electric controllers lack fail-safe position features for larger pipes operating at high pressures, with high torque. Similarly, critical valves may require a short actuation time that cannot be accomplished with an electric controller.

At a minimum, commenter (1391-INGAA) suggests that EPA keep the functional needs exemption in place for the transmission and storage segment. The commenter notes that the exact same rationale that applied in 2011 when EPA promulgated NSPS OOOO—and again in 2016 when it promulgated NSPS OOOOa—remains relevant today. They explain that functional requirements related to safety and reliability warrant the use of gas-driven pneumatic controllers in some cases. The commenter states that EPA has not identified anything in the November 2021 Proposal that shows why it has changed its position on this important safety and reliability issue.

Similarly, commenter (0782-BHE) states that, in the original NSPS rulemaking (NSPS OOOO), EPA provided rationale for exemptions due to functional need. They add that the same approach was retained in NSPS OOOOa. Importantly, the commenter notes that the premise has not changed (quotes info from NSPS OOOO proposed rule and NSPS OOOOa TSD). The commenter states that EPA has not provided an explanation as to its perception that a functional need exemption is no longer needed. The commenter notes that, perhaps EPA believes that solar powered electrical controllers provide a solution to address this service and then elaborates how solar power is infeasible and unreliable with respect to: (1) timely actuation of large mainline/ESD valves, and (2) remote metering and regulating stations along a transmission lines and locations where additional siting and permitting are required. The commenter contends that it is imperative that EPA retain pneumatic controller exemptions due to functional need particularly in the transmission and storage segments to ensure safe and reliable operations. The commenter recommends retaining an exemption for functional need, with exceptions documented by the operator. Regarding implementation of the exception, the commenter recommends that recordkeeping analogous to current NSPS OOOOa requirements could be retained for such controllers. The commenter adds that operators could maintain records to support the exemption and that a list of controllers that are exempt due to functional need can be maintained so that the implications of this exception can be characterized.

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<sup>46</sup> EPA, Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry, 2 (Oct. 2006), [https://www.epa.gov/sites/default/files/2016-06/documents/ll\\_pneumatics.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/ll_pneumatics.pdf).

<sup>47</sup> The commenter states that the 2021 Technical Support Document (2021 TSD) incorrectly assumes that electrical supply is available at a given site. See EPA, 2021 TSD for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG), 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (2021 TSD), 8-21.

<sup>48</sup> See the Confidential Appendix for an example cost of electrical service installation.



Commenter (0782-BHE) states that the November 2021 Proposal appears to acknowledge that exceptions for functional need are still required for Alaska, where electric power is not available and the efficacy of solar-based electricity is questioned by EPA. According to the commenter, they have no knowledge (1) of an analysis that justifies a conclusion that the same issue does not exist in locations other than Alaska, (2) that solar reliability will not compromise system safety and reliability at other locations, or (3) that a solar-powered electric controller can provide the same motive force and time response as a natural gas driven pneumatic controller utilizing high pressure natural gas available at all transmission and storage sites.

Another commenter (0844-EDF *et al.*) indicates that the technical feasibility or functional needs exemptions should only be allowed in very limited instances and only when justification is provided in an annual report.

Commenter (0782-BHE) states that if EPA does not provide pneumatic controller exceptions for functional use and/or exclude pneumatic controllers in remote locations along transmission pipelines, significant new electricity resources will be required in many locations, *e.g.*, potentially hundreds of relatively remote locations for the commenter's operations. The commenter adds that significant power supply uprate may be necessary at existing facilities for electric actuators that require quick response on a high energy application (*e.g.*, closing a large mainline valve). The commenter believes that it will require time to design, construct, and implement adequate energy resources to meet the demand, and an extended schedule or phased-in implementation may be warranted.

Response I-10-31: See discussion in section IV.D.1.b.i of the December 2022 Supplemental Proposal (87 FR 74759) for response to comments regarding the functional needs exemption. Regarding an implementation timeline for existing sources, similar comments were made on the December 2022 Supplemental Proposal. See response in Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), Response II-7-80.

Comment: Commenter (0831-AXPC) recommends that retrofitting of existing pneumatic controllers to non-emitting be based on a technical feasibility assessment that includes: (1) that there are more than five controllers at the well site, central production facility, or compressor station; and (2) that the site has access to sufficient grid power onsite and/or that there is a feasible route from specific controllers to an existing combustion device. In circumstances found not feasible, the commenter suggests that EPA allow the use of continuous low-bleed and intermittent natural gas controllers and that they be covered in an operator's existing LDAR monitoring program to monitor proper functioning, similar to EPA's suggested requirements for Alaska.

Response I-10-32: See section IV.D.1.b.i of the December 2022 Supplemental Proposal (87 FR 74765-76766) and also the final rule preamble sections XI.D.2 and XI.D.3 for discussion about the feasibility of attaining zero emissions from process controllers.

Comment: Commenter (0782-BHE) recommends, for existing sources [context: pneumatic controllers] the EGs include a case-specific alternative mitigation review and technological and economic feasibility assessment, analogous to provisions for existing sources common in ozone

state implementation plans. The commenter recommends including in the EGs an option analogous to “alternative [reasonably achievable control technology] RACT” provisions in VOC and NO<sub>x</sub> rules for ozone state implementation plans (SIPs). Case-specific review may indicate significant costs with minimal environmental benefit and other deleterious impacts. The commenter states that case-specific review would likely identify significant hurdles and costs in some instances. The commenter notes that this is standard practice for other existing source regulations and should apply to this GHG/VOC program that follows a similar regulatory paradigm.

Response I-10-33: The EPA has determined that there are zero-emission compliance methods that are implementable at a reasonable cost. See sections IV.D.2.c and d of the December 2022 Supplemental Proposal (87 FR 74768-76769) and also the final rule preamble section XI.D.3 for discussion of the EGs for process controllers.

#### *Case-by-Case Exemptions Based on Engineering Judgement*

Comment: Commenter (0787-Atmos) recommends that EPA allow case-by-case exemptions as in Colorado regulations. The commenter states that, if EPA does proceed to require no-bleed devices, it could allow for companies to submit a justification to the agency that would allow an individual exception in cases where such devices are not appropriate for a particular site due to safety or operational purposes. The commenter notes that this would align with Colorado’s updated pneumatic controller regulations that took effect in February 2021, which explicitly allow high-bleed pneumatic controllers to remain in service due to safety and/or process purposes and require the owner/operator to submit justification for using these controllers.<sup>49</sup> The commenter adds that it would also align with EPA’s November 2021 proposed exemption requirements from using a no-bleed pneumatic controller at natural gas processing plants.<sup>50</sup>

Another commenter (0817-GPA) states that the November 2021 Proposal provides no rationale for removing exemptions “where engineering judgment recommends” the use of natural gas-driven pneumatic controllers “to maintain safety, reliability, or efficiency.” The commenter notes that the November 2021 Proposal assumes, without any record basis, that electric controllers are at least as reliable and functional as gas-powered actuators. In fact, as noted, electric controllers are less reliable and functional, lacking in speed and having a higher failure rate, especially for throttle service. The commenter states that this is confirmed in EPA’s Carbon Limits report. See Carbon Limits at 16 (“As a rule, electric controllers/ actuators will stay in position if the system fails and power is lost, wires are cut, or other failures occur,” not in a “fail safe” position). The commenter requests that EPA reconsider the substantial potential for controller failures, both with respect to increased safety risks and increased emissions.

Response I-10-34: The EPA has determined that exemptions for high-bleed controllers are not necessary and has excluded emergency shutdown devices from the affected source. See sections

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<sup>49</sup> See, e.g., 5 C.C.R. 1001-9-D-III.C.1.c(ii) (“For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.”).

<sup>50</sup> 86 Fed. Reg. at 63,208.

IV. D.1.b.i and IV.D.2.c of the December 2022 Supplemental Proposal ((87 FR 74759 and 74768) and for further discussion of these issues.

### ***10.8.2 Transmission and Storage Segment Exemption***

Comment: Commenters (0782-BHE, 1391-INGAA) recommend that EPA exempt pneumatic controllers in the transmission and storage segment due to very low emissions. The commenters state that, as summarized in EPA's 2021 TSD<sup>51</sup>, pneumatic controller emissions are relatively significant for upstream operations (*i.e.*, greater than 20 percent of methane emissions from all affected segments), while pneumatic controller emissions from the transmission and storage segment are very minor and insignificant. However, the commenters point out that methane emissions from pneumatics in the transmission and storage segment comprise less than one percent of the total methane emissions from pneumatics in the source category.

In November 2019, the commenter (1391-INGAA) states that they met with EPA staff associated with EPA annual GHGI report and Subpart W of the GHGRP. The commenter reports that they provided EPA with a report by the Pipeline Research Council International that presents an analysis of six years of Subpart W reporting data for transmission and storage sources.<sup>52</sup> They note that the report includes a review of pneumatic controller data for hundreds of facilities that report annually. The data indicate that methane emissions from pneumatic controllers in the transmission and storage segment are more than 13 percent lower than the value presented in the EPA annual GHGI, based on a compressor station-level emission factor. Thus, the commenter asserts that the relatively low emission levels discussed above are even lower based on more recent data available from the GHGRP.

The commenter (1391-INGAA) provides an example from one of their members that operates a station in South Carolina that highlights this point. This station, which sits in a remote area without an electrical power, protects a 22-mile stretch of 8-inch pipe with a lower maximum operating pressure than its upstream source. There are two regulators and two monitors with gas-driven pneumatics at the station. The regulators are redundant, with only one regulator operating under normal conditions and the other regulator serving as a backup. The regulators are controlled with Becker pilots, which will bleed only when the regulator needs to move. The backup regulator does not move unless it must meet downstream pressure requirements. The two monitors are also driven by Becker pilots and only come into service if there was a primary or secondary regulator failure. The monitors will not bleed in normal operating conditions – only in the event of a failure. The commenter notes that, even if there was a regulator failure, these monitors bleed far less gas than a relief valve would. According to the commenter, this example demonstrates that much of the equipment in the transmission segment does not emit frequently because it serves only a backup function.

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<sup>51</sup> U.S. EPA, Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG), at Table 8-2 (Oct. 2021) (Docket ID No. EPA-HQOAR-2021-0317-0166).

<sup>52</sup> Pipeline Research Council International (PRCI) White Paper, Methane Emissions from Transmission and Storage Subpart W Sources, PRCI Catalogue No. PR-312-16202-R03 (Aug. 2019). This report is attached to these comments as Attachment 6.

In other words, the commenter (1391-INGAA) contends that, although pneumatic controllers may be a significant contributor to methane emissions from the source category overall, they are not a significant contributor from the transmission and storage segment. As a result, the commenter states that the November 2021 Proposal would introduce pipeline and compressor station safety risks for a nominal emission reduction.

Response I-10-35: In the final NSPS and EG, the EPA is requiring that there be zero emissions from process controllers located at sites meeting certain conditions, which are those that have access to electrical power and those that do not have access to electrical power and are located in Alaska. At these sites, all process controllers in the process controller affected source are required to meet this standard, which includes process controllers in the transmission and storage segment. See sections XI.D.1 through 3 of the final rule preamble for more information on the EPA's BSER analysis and the final emissions standards for process controllers.

#### ***10.8.3 Temporary/Non-stationary/Completion Equipment Exemption***

Comment: Commenters (0599-MSD, 0808-API, 0831-AXPC) encourage EPA to provide an exemption for "temporary sources." Commenter (0831-AXPC) provided the example where an operation may require use of temporary or portable equipment for a short period of time (*i.e.*, less than 180 days) where it may not be possible to connect to the grid or route to an onsite control device. Commenters (0599-MSD, 0808-API) indicate that non-emitting requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico and finalized in Colorado. The commenters indicate that EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.

Response I-10-36: The EPA acknowledged in the December 2022 Supplemental Proposal that the focus of the BSER analysis has been on process controllers that are part of the routine operation of oil and natural gas facilities. We noted that we did not have sufficient information to include an exemption or an alternative standard for process controllers associated with temporary equipment, and we requested more information about these situations. The EPA requested information regarding when temporary equipment is used, the function of the controllers during this time, how they are powered, and the typical duration of their usage. The EPA also requested information explaining in detail why the zero-emission solutions that are used for the permanent equipment at the site cannot be also used for this temporary equipment. As the EPA did not receive this information or further explanation, the EPA has insufficient support for an exemption or alternative standard. Therefore, the final rule has not been revised to separately address process controllers on temporary equipment.

#### ***10.8.4 Need for Gas-Driven Backup System Option***

Comment: Commenters (0749-PAW, 0817-GPA) request that EPA allow companies the option to continue to use, or install, a dual natural gas system as a backup for key controller functions. The commenters note that such a natural gas backup system would be used in the case of electrically actuated controller failure, loss of power, extended insufficient solar generated power, or other contingencies. Another commenter (0599-MSD) adds that, if the zero-emissions

system (*i.e.*, instrument air) goes down, there is no provision within the proposed rule to allow for the temporary use of natural gas. The commenter urges EPA to evaluate the reliability and availability of such systems that would be deployed at such breadth.

Response I-10-37: The information regarding zero-emission process controller technologies available to the EPA does not suggest that a natural gas-driven back-up system is necessary. For compressed air systems used to power pneumatic process controllers, the systems are designed with two compressors to ensure one is always available in the case of a malfunction of the other. If the system uses power from the grid, the system could be designed to have an alternate power source, such as a generator, to ensure the compressed air system does not lose power. If electrical process controllers are used, an alternate power source could also be used to ensure the process controllers continue to function, such as a generator or a battery system. Therefore, the use of natural gas-driven process controllers is not necessary to provide an alternative in the case of a power failure.

#### ***10.8.5 Emergency Shutdown Devices (ESDs) Exemption***

Comment: Several commenters (0411-Riverside Energy Michigan (REM), 0599-MSD, 0808-API, 0831-AXPC) raised the need to utilize natural gas-driven pneumatic controllers associated with ESDs and requested that EPA confirm that emergency shutdown valves or devices are not considered pneumatic devices or that emergency shutdown devices remain exempt from the proposed pneumatic controller requirements. Commenters (0808-API, 0831-AXPC) explain that an ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. According to the commenters, it is rare that ESDs are activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. Commenters (0808-API, 0831-AXPC) note that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.

Commenters (0782 BHE, 1291-INGAA) indicate that the DOT/PHMSA is undergoing a rulemaking right now that proposes “standards for valve installation, rupture recognition and timely mitigation, and valve shut-off and location requirements for segment isolation.” In order “to minimize consequences from ruptured pipeline segments and improve the effectiveness of emergency response.” The commenters state that EPA needs to be aware of this rulemaking and needs to coordinate with PHMSA to be sure that the requirements contemplated here do not conflict with PHMSA. Commenter (1291-INGAA) provides that catastrophic failure can cause control systems, power systems and compressed air systems to fail. They add that, if battery limit valves (those needed to isolate and blow down the facility) are depending on any of those systems, it becomes impossible to shut down and isolate the station from its associated transmission lines, resulting in a much worse accident. They explain that battery limit valves that are gas powered function independently from the above systems and are usually actuated to a safe position by loss of a gas pilot signal. They add that many have power storage tanks to ensure that they are able to operate even when supply pressure to the actuator is removed or disrupted. They conclude by stating that the bottom line is that the only 100 percent reliable method for

powering important ESDs is stored energy available from the pressurized natural gas in the transmission line.

Commenter (0844-EDF *et al.*) states that ESD systems are reliable control systems designed to protect personnel and the facilities in case of an unexpected event such as over pressurization. The commenter notes that, in 2016, when EPA issued NSPS OOOOa, electric valve systems were generally not considered to be reliable enough for ESD systems, so it was assumed that gas driven controllers would still be used for ESD systems, even when the rest of the facility was converted to electronic controllers. Today, however, the commenter asserts that there are reliable zero-emission ESD systems on the market, including systems utilizing uninterruptible power supply device and systems utilizing a failsafe controller in an emergency shutdown valve electric actuators system.<sup>53</sup>

Commenter (0817-GPA) states that because an intermittent bleed controller that manages an emergency shutdown down (ESD) is only used intermittently, the only associated emissions from such a controller would be no larger than the pneumatic's diaphragm size. The commenter adds that, unless there is a true emergency, ESD systems are usually only tested annually; therefore, the intermittent pneumatic controller would only actuate once per year. According to the commenter, the costs associated with modifying these pneumatics to comply with the November 2021 Proposal are absolutely not outweighed by any potential benefit gained by reducing such de minimis emissions here.

Response I-10-38: The EPA has excluded emergency shutdown devices from the affected source. See sections IV. D.1.b.i and IV.D.2.c of the December 2022 Supplemental Proposal ((87 FR 74759 and 74768) for further discussion of this issue.

#### ***10.8.6 Small Site Exemption***

Comment: Commenter (0814-IPAA *et al.*) requests that EPA include an exemption for small sites with low production and/or a low number of pneumatic controllers. The commenters provide a range of pneumatic controllers that they felt represented a reasonable cut-off, ranging from 3 to 30 controllers. The commenter notes that EPA's cost estimates for electric and solar retrofits in the 2021 TSD and notes that while EPA presents its cost effectiveness assessment in the context of cost per unit of recovered methane and/or VOC, the real impact on a small well site would be overwhelming. The commenter elaborates that even at the current prices for natural gas, it would take the average low-production natural gas well about six years of all its profits to pay for the electric grid option and more than that for the solar option. The commenter adds that for a Pennsylvania well site, the time would be 70 or more years.

The commenter requests that EPA develop its emissions guidelines for existing sources based on well sites normal emissions patterns. The commenter states that the concept of using a well site emissions threshold is appropriate to creating more cost-effective regulations for low production well sites and should be expanded to other components. The commenter contends that pneumatic controllers are an appropriate example. The commenter explains that low production operations have limited numbers of pneumatic controllers and are frequently located in remote areas

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<sup>53</sup> Carbon Limits 2021 at 7.

without access to power. The commenter notes that EPA has recognized these realities in the past. The commenter asserts that EPA should exclude low production well sites emitting 3 tons/year or less from the scope of its emission guidelines for pneumatic controllers. Alternatively, the commenter suggests that EPA provide for a threshold number of pneumatic controllers to be present at a well site before the pneumatic controller requirements are applied, a threshold that reflects the cost effectiveness of the requirement based on the ability of the well site to absorb the cost.

Commenter (0599-MS) encourages EPA to establish a threshold (*e.g.*, count of components) under which the EG OOOOc does not apply, where the emission reductions would be minimal but expensive to achieve.

Commenter (0777-Ascent) requests that EPA include an exception from the existing source guidelines' pneumatic controller requirements for small well sites with three or fewer pneumatic controllers per well. The commenter states that the cost of converting to an electronic controller or instrument air system will likely result in the shut-in of many small, low-production well sites. The commenter notes that sites have a remaining useful life that will be cut short by the proposed rule's pneumatic controller requirements.

Commenters (1267-CA AG *et al.*) state that Colorado exempts operators from complying with many components of their program requirements if their "total statewide oil and natural gas production average[es] 15 barrels of oil equivalent or less per day per well," *id.* § III.C.4.c.(iv)., in addition to other limited exemptions.

Response I-10-39: See section IV.D.2.d.i of the December 2022 Supplemental Proposal (87 FR 74769) and section XI.D.2 of the preamble to the final rule for discussion of small well sites.

Comment: Commenter (1341-Conventional Groups) states that EPA ignored or failed to address several key recommendations of the Small Entity Representatives Panel Report. The commenter asserts that the recommendations provided in the report are crucial for small conventional well sites. The recommendation that "EPA only propose zero-emission [pneumatic] controllers at sites with reliable and consistent onsite power available and clearly state that the intent is not require the installation of electric services for this purpose." *Id.* at 36. Instead of following the Panel Report's recommendation, EPA's November 2021 Proposal provides that sites without electricity can use mechanical controllers and electronic controllers using solar power.

Response I-10-40: In its BSER analyses, the EPA found there are zero-emitting process controller technologies that are technically feasible and reasonable in terms of costs and other impacts at locations with and without electrical power. See section IV.D.2.c of the December 2022 Supplemental Proposal (87 FR 74768) and the final rule preamble section XI.D.3 for discussion of the BSER. In addition, as noted in Response I-21-6, pursuant to section 603 of the RFA, the EPA prepared an IRFA that examined the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the 2022 RIA (see section 4.3).

### ***10.8.7 Wellhead-only Sites***

Comment: Commenter (0749-PAW) states that EPA should exempt gas-driven controllers at “wellhead-only sites” as the cost-benefit analysis is not the same at wellhead-only sites as with gas-driven controllers at sites with production equipment (tanks, dehydrators, separators, etc.). The commenter explains that “wellhead-only sites” do not have existing process equipment or control devices that centralized production facilities may have. Further, the commenter adds that EPA excludes “wellhead-only sites” from fugitive emissions monitoring (FEM) provisions. The commenter asserts that EPA should also exclude “wellhead-only sites” from applicability for gas-actuated controllers for similar reasons. EPA states on page 63205 of the November 2021 Proposal preamble, “For the vast majority of situations...we evaluated these zero emission controller options using ‘model’ plants.” The commenter provides that sites exist that only have a single gas-actuated controller (*e.g.*, wellhead-only sites) and therefore ‘model’ plant cost analyses may not accurately reflect the true costs for wellhead-only sites.

Response I-10-41: See section IV.D.2.d.i of the December 2022 Supplemental Proposal (87 FR 74769) and section XI.D.2 of the preamble to the final rule for discussion of small well sites.

### ***10.8.8 Remote Locations not at a Well Pad, Processing Plant or Compressor Station***

Comment: Commenter (0599-MS) states that for new sources regulated under NSPS OOOOb, locations not at well pads or compressor stations (such as interconnections), access to grid power (and zero bleed devices) should be limited to commercially available onsite connections with sufficient and reliable power, which is a subset of sources. The commenter explains that these locations in general have a limited number of pneumatics (less than the number in the small model plants). The commenter notes that a cost analysis has not been performed for these sites. If such an analysis is not included in an updated proposal, these locations should be exempt from the design requirements.

Another commenter (0817-GPA) states that EPA should retain the exemption for natural gas driven-pneumatic controllers for uses other than at a compressor station or natural gas plant, such as along a pipeline, “where engineering judgment recommends their use to maintain safety, reliability or efficiency.” The commenter explains that these would include controllers at remote meter stations, above-ground pipeline junctions, and generally those along the gathering system as well as skid-mounted temporary equipment, and pig launchers and receivers. The commenter adds that these controllers are even less likely than compressor stations to have access to electricity, requiring in most cases the operation of a generator at a small, unmanned, and remote facility. Further, they serve key functions, such as regulating customer inlet to the gathering system or allow for the automatic shutdown of the pipeline. The commenter provides that the loss of power, or a controller failure, could shut customers out of the gathering system or preclude remote or automatic system shutdowns in the event of a rupture. The commenter asserts that these are vital commercial, safety, and environmental functions that should not be compromised. Importantly, the commenter states that EPA provides no explanation for eliminating the exemption for these types of controllers.



Response I-10-42: The EPA has found in its BSER analysis that there are zero-emissions process controller options that have costs that are reasonable considering the emissions reductions that would be achieved at all model plants studied. See section IV.D.2.d.i of the December 2022 Supplemental Proposal (87 FR 74769) and section XI.D.2 of the preamble to the final rule for discussion of small well sites. For discussion of the removal of the functional needs exemption, see section IV.D.2.d.i of the December 2022 Supplemental Proposal (87 FR 74759).

#### ***10.8.9 Categorical Exemption for Sites without Available Electrical Power***

Comment: Commenter (0844-EDF *et al.*) requests that EPA limit the categorical exemption for sites where power is not available to sites in Alaska. The commenter explains that, if the feasibility of zero-emitting technology is growing in Alberta, Alaska and other northern regions, then they do not believe there is any reason to extend the proposed blanket exemption to geographies beyond Alaska.<sup>54</sup>

Response I-10-43: In the final rule, the EPA has not extended the exemption from the zero-emissions requirements to sites beyond those in Alaska without access to electrical power.

### **10.9 BSER Analysis**

#### ***10.9.1 Emissions/Emissions Factors***

Comment: Some commenters object to the emission factors that were used for the 2021 TSD analysis. Commenter (0749-PAW) states that the emission factors used in the GHGRP petroleum and natural gas source category (40 CFR part 98, subpart W, also referred to as “GHGRP subpart W”) for pneumatic controllers were developed in the 1990’s and that they may no longer be applicable considering technological improvements. Another commenter (0918-COLGC) indicates that the factors used underestimate emissions and that recent research indicates that actual average emissions from pneumatic controllers may be higher than estimated.

Response I-10-44: The EPA revised its BSER analysis for the December 2022 Supplemental Proposal and again for the final rule using the most up-to-date emissions factors available. See section IV.D.1.b.ii of the December 2022 Supplemental Proposal (87 FR 74760) and section XI.D.3 of the preamble to the final rule, as well as the TSD for each rulemaking for further information regarding the revised BSER analyses and the specific emission factors used.

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<sup>54</sup> The commenter notes that feasibility in Alaska is also reason to consider not including a blanket exemption for the state, though we don’t go into detail on that issue in this comment. At the very least, EPA should address the environmental justice concerns that arise because of the exemption. As the National Tribal Air Association has remarked, the proposal as it stands doesn’t adequately protect Alaska Native Villagers and Alaskan Tribes and ensure sufficient consultation and coordination with Tribes. To address that, EPA should develop Tribal Plans, and create systems for tribal governments to participate in monitoring and state plan development. See National Tribal Air Association, NTAA’s Informational Webinar on EPA’s Oil & Natural Gas Rule (Jan. 19, 2022), <https://secureservercdn.net/198.71.233.206/7vv.611.myftpupload.com/wp-content/uploads/2022/01/NTAAPresentation-for-Methane-Informational-Webinar-1.19.22.pdf> We urge EPA to consider these concerns when finalizing its rule.

Comment: Commenter (0808-API) indicates that while they appreciate that EPA utilized emission factors from the API's *Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas*<sup>55</sup>, they believe that the use of the average intermittent pneumatic device vent rate was incorrect in this application. They state that under the November 2021 Proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor is 0.28 scf whole gas/controller-hour, not the average emission factor of 9.2 scf whole gas/controller-hour that EPA uses in the November 2021 Proposal as documented in API's *2021 GHG Compendium* Table 6-15.<sup>56</sup> The commenter notes that the average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The commenter adds that the normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program and contends that this approach achieves a nearly similar level of emission reduction for much less investment by operators.

Response I-10-45: EPA agrees with the commenter that the lower emission factor is appropriate to represent the emissions level for intermittent vent controllers that are routinely monitored as part of a proactive monitoring and repair program. While EPA recognizes that some companies have voluntarily implemented such programs, we do not have information to suggest that the majority of the intermittent vent controllers in operation are part of such a program. The average emission factor that EPA used considers those low-emitting properly operating controllers, as well as those that are not operating properly and that are venting during idle. EPA finds that this average factor is the correct factor to represent the "uncontrolled" emissions from the universe of intermittent vent controllers.

We note that in our refreshed BSER analysis conducted for the final rule, the most up-to-date emissions factors were used, which included those used in the final GHGRP revisions. However, the final GHGRP does not include an emission factor for intermittent vent controllers, and instead requires that sites calculate emissions for each site based on site-specific measurements. Therefore, to estimate emissions from intermittent vents, the EPA used an average emission factor of intermittent vent emissions from a recent study that includes both properly functioning and malfunctioning intermittent vent process controllers.<sup>57</sup> The emission factor from this study was used rather than the API's *Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas* emission factor, as this study underwent review as part of the journal article publication process. As these emission factors have been updated recently and are based on data from field studies of emissions from process controllers, these emission factors are the best data available to estimate nationwide emissions from process controllers. The EPA does not anticipate that the use of these emission factors significantly overstates or understates emissions.

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<sup>55</sup> API's Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas." Presented on November 7, 2019, in Pittsburgh PA by Paul Tupper.

<sup>56</sup> <https://www.api.org/~media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf>

<sup>57</sup> Luck, B., D. Zimmerle, T. Vaughn, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, L. Williams, and D. Allen. 2019. "Multi-Day Measurements of Pneumatic Controller Emissions Reveal Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations."

Comment: Commenter (0808-API) states that, in EPA's cost-effectiveness analysis, updating the intermittent controller emission rate to the properly functioning emission rate reduces the baseline emissions for each model plant significantly, which directly reduces the potential emission reductions. When coupled with the fact that EPA underrepresented the actual costs for conversion to non-emitting technologies, the commenter contends that the cost-effectiveness for the November 2021 Proposal under NSPS OOOOb and EG OOOOc quickly becomes not cost-effective either for methane or VOC with or without savings.

Response I-10-46: The EPA used updated emissions factors and cost information in its revised BSER analysis conducted for the December 2022 Supplemental Proposal and the final rule. The EPA continues to find that zero-emissions options are available for process controllers with costs that are reasonable considering the emissions reductions that would be achieved. See section IV.D.1.b.ii of the December 2022 Supplemental Proposal (87 FR 74760) and section XI.D.3 of the preamble to the final rule, for further information regarding the revised BSER analyses.

### ***10.9.2 Costs Used***

Comment: Commenters (0844-EDF *et al.*, 0924-U.S. Small Business Administration (SBA)) disagree with the costs used for the November 2021 Proposal BSER analysis. Commenter (0844-EDF *et al.*) states that EPA's cost estimates were taken directly from the 2016 Pneumatic Controller White Paper and that EPA did not update the cost numbers for zero-emission electronic controllers, solar panels, or batteries. The commenter adds that EPA notes the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry. The commenter points out that Carbon Limits updated their report in early 2022 and recommends that EPA utilize the more recent information in that report since it includes more up-to-date research on zero-emissions options for pneumatic controllers.

Response I-10-47: We reviewed the updated 2022 Carbon Limits report, and we agree with the commenter that the information presented is well-researched and representative of the costs of zero-emission pneumatic controller technologies. In addition to updating the analysis to reflect the information in the 2022 Carbon Limits report, we also increased the estimate of installation costs and considered operation and maintenance costs for all types of pneumatic controller systems not driven by natural gas.

Comment: Commenter (0749-PAW) states that, for zero emission electrical controller setups, skilled electrical labor is required for wiring, programming, and tuning, which cannot be conducted by lease operators that would otherwise manage this equipment. According to the commenter, one available estimate is as high as \$20,000 in labor costs per multi-well pad.

Response I-10-48: In the BSER analyses, the EPA included separate costs associated with installation of equipment for zero-emissions process controllers, which varies depending on whether the site is new or existing and the type of zero-emissions option shown. These costs are in addition to the equipment costs. See the TSDs for the December 2022 Supplemental Proposal and the final rule for further details regarding the specific labor costs included in the BSER

analyses. See also section IV.D.1.b. ii of the December 2022 Supplemental Proposal preamble (87 FR 74761).

Comment: Commenter (0808-API) states that the emission reduction benefit from fixing improperly functioning controllers [covered by LDAR] is currently already captured in EPA's cost-effective analysis for the proposed LDAR requirements. The commenter notes that this approach achieves nearly a similar level of emission reduction for much less investment by operators. The commenter provides that this is especially true when converting a single existing high-bleed controller with a properly functioning intermittent controller that is part of a company's LDAR program. Furthermore, the commenter adds that if an existing facility only contains properly functioning intermittent controllers confirmed through an LDAR program, then the cost-effectiveness evaluation never becomes cost-effective for any amount of controllers even assuming EPA's own cost assumptions.

Response I-10-49: The EPA agrees that if all intermittent controllers were properly functioning, emissions would be reduced. However, the EPA also found that zero-emissions options are available which reduces emissions from all continuous bleed process controllers as well as intermittent vent controllers. In the EPA's BSER analysis, the EPA determined that technically feasible zero-emissions options are available at costs that are reasonable, considering the emissions reductions that would be achieved. Therefore, the EPA determined that zero emissions represents the BSER for process controllers, and this is reflected in the NSPS and EG.

Comment: Commenter (0808-API) provides estimated costs for an instrument air system driven by a natural gas generator and for an instrument air system powered by solar energy. The commenter states that they conducted a member survey of costs for grid-powered instrument air systems, solar-powered instrument air systems and natural gas generator-powered system. The commenter provides that costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, enough batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with the use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees. According to the commenter, all instrument air systems typically require annual maintenance at a cost of between \$2000 and \$4000 per year. Installation of non-emitting controllers also requires shutting-in the well or facility, an additional cost which does not appear to be accounted for in EPA's cost analysis. The commenter states that the results indicate the following:

- For smaller facilities, the average cost for a grid powered instrument air system was estimated at \$51,000 and for a natural gas generator powered instrument air system around \$60,000. The survey had no data for solar powered instrument air system. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems. For their analysis, they assume an average annual maintenance cost of \$3,000.
- For medium facilities, the average cost for a grid powered instrument air system was estimated at \$80,000 and for a natural gas generator powered instrument air system around

\$110,000. The survey had no data for solar powered instrument air system. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems. For their analysis, they assume an average annual maintenance cost of \$3,000.

- For large facilities, noted as multi-well sites, central production facilities or compressor stations (with more than 100 controllers) the average cost for a grid powered instrument air system was estimated at \$143,333; for a natural gas generator powered instrument air system around \$207,250; and for a solar powered instrument air system around \$250,000. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems. For their analysis, they assume an average annual maintenance cost of \$3,000.

The commenter (0808-API) also provides an analysis, *Cost Effectiveness Evaluation for Retrofit of Existing Pneumatic Controllers*, where they evaluated the minimum number of controllers that would be cost effective to retrofit to an instrument air system powered by grid power or a natural gas generator, using the minimum costs they listed in Table 3 of their comment letter [and noted above]. The results indicate that, for a facility containing low bleed controllers and properly functioning intermittent controllers, it would only be cost effective to retrofit if there were at least 15 to 30 controllers, depending on the single/multi-pollutant, with or without savings approach, that EPA analyses.<sup>58</sup> The commenter contends that EPA based their model plant analysis on incorrect assumptions. The commenter notes that, based on blinded data collected from their member companies by a third-party, EPA has underestimated the costs and overestimated the benefits for converting pneumatic controllers to non-emitting. According to the commenter, the variation in the costs estimated by EPA with API member costs is centered on incorrect assumptions by EPA that companies will use grid power or solar based systems to power electric controllers. The commenter states that their members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas generators and are only in the initial phases of testing the reliability of solar based instrument air systems.

Additionally, the commenter (0808-API) notes that their member's experiences have indicated that EPA's distinction between the small and medium model plant is incorrect when it comes to cost variation since a site with either 4 or 8 controllers would be considered a relatively small facility with minimal equipment. Some multi-well sites, central production facilities and compressor stations may contain 100-200 controllers. The commenter reports that these larger facilities are typically the types of facilities that operators have been successful in retrofitting pneumatic controllers to non-emitting in a cost-effective manner by placing the investment of retrofit on the facilities with the most controllers.

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<sup>58</sup> To estimate baseline emissions, the commenter assumes a mix of controllers onsite of 30 percent low-bleed and 70 percent intermittent, which is consistent with the breakdown of controller types reported to EPA for the 2020 calendar year pursuant to 40 CFR Part 98, subpart W. The commenter contends that EPA was incorrect to assume a high bleed pneumatic controller within their model plant analysis as the count of high bleed controllers is only 1 percent for the production segment and 3 percent for the gathering and boosting segment based on the 2020 Subpart W data (refer to Attachment A, Table C-1). The commenter also applied the properly functioning emission factor from Table 6-15 of API's GHG Compendium based on the comments offered herein.

Response I-10-50: Considering this comment, the EPA updated its BSER analysis to include the information provided. See section IV.D.1.b. ii of the December 2022 Supplemental Proposal preamble (87 FR 74762) and the TSD for the December 2022 Supplemental Proposal for further information on the specific costs used in the BSER analysis.

Comment: Commenter (0743-WEA) states that EPA has significantly underestimated the cost and difficulty of retrofitting facilities to comply with the regulation and that one of their member companies estimates from an actual retrofit project's range to be as high as \$250,000 per facility for large facilities with many controllers. The commenter notes this is a price point far outside the range described in EPA's publication. While these costs may be lower for lower-producing facilities, the commenter states that the fact EPA estimated the top end for the range for large facilities to be only \$96,000 signals there is a flaw in the calculation for it to be that far off actual project execution.

Response I-10-51: Similar comments on costs were provided on the December 2022 Supplemental Proposal. For response to this comment, please see Volume II, Chapter 7 (Process Controllers), subsection 7.3.3 (Costs), Response II-7-67.

Comment: Commenter (0749-PAW) states that costs for zero-emission controllers are high and must be adequately considered. The commenter provides the following cost estimates for control technologies:

- Commenter member companies estimate that zero emission controller setups will cost more than \$13,000 per setup (one water and one oil dump). For new and modified sources, this is nearly 2.5 times more costly than traditional low and intermittent bleed setups.
- Instrument air systems would be easier and significantly less costly for new facilities than existing sources and are estimated to cost between \$33,000 and \$80,000.
- Many locations in Wyoming lack line power and are unable to route line power due to other resource implications such as sage grouse. For these remote locations, the cost for solar power packages (which may not be reliable enough to satisfy safety concerns) is approximately \$50,000 per pad. For locations that can bring line power in, costs range from \$25,000 to \$60,000 per location.
- If electric power is not available at the site, that is a significant additional cost. For instance, a remote well that is 1/4 mile from line power and for 2 phase 120V standard service is estimated to cost \$25,000. For the heavier duty 480V service it is around \$60,000.

Response I-10-52: The EPA used the best available information regarding the costs of zero-emissions controller setups and installation. See section IV.D.1.b. ii of the December 2022 Supplemental Proposal preamble (87 FR 74760-74763) and the TSD for information regarding the specific costs included in the revised BSER analysis. Also see section XI.D.1, 2, and 3 of the preamble to the final rule and the final rule TSD for information regarding the costs included in the refreshed BSER analysis conducted for the final rule.

Comment: Commenter (0844-EDF *et al.*) states that EPA did not calculate cost-effectiveness for routing to a VRU from pneumatic controllers in its November 2021 Proposal, but, for its final rule they urge the agency to consider the faulty premises from which its 2016 and 2021

calculations for VRU cost-effectiveness were based, and to conduct a cost analysis for routing controllers to a VRU that is based on more reliable factors. The commenter notes that EPA's current cost analysis relies on three outdated VRU capital cost estimates, two of which are from the oil and gas industry. The commenter recommends that EPA update its analysis to include a more representative sample, which they believe could result in greater cost-effectiveness for this approach. Indeed, according to the commenter, if EPA omitted the particularly high estimates provided by the Gas Processor Association, the annualized costs for routing controllers to a VRU drops from \$869 to \$624 (2019 USD). Assuming EPA's reported emissions rate of 9.2 scf/hr for intermittent vent controllers, the commenter states that sites with at least 2 controllers will spend about \$200 per ton of methane avoided without savings and will incur modest net savings at a gas price of \$4 per Mcf (about \$6 benefit per ton of methane avoided).<sup>59</sup>

**Response I-10-53:** While the EPA did not evaluate the cost-effectiveness of routing emissions through a VRU to a process, the EPA did find that there are zero-emission process controller options for which the cost-effectiveness is within the ranges considered to be reasonable by the EPA. See section IV.D.1.b. iii of the December 2022 Supplemental Proposal preamble (87 FR 74763). The zero-emissions requirements of the final NSPS and EG are technology-neutral, and owner/operators may choose to route process controller emissions through a VRU to a process. See section XI.D.2 of the preamble to the final rule for discussion of the determination of BSER for process controllers.

### ***10.9.3 Model Plant Analysis***

**Comment:** Commenter (0749-PAW) notes that all three sizes of model plants (small, medium, large) contain one high-bleed natural gas-driven controller. The commenter indicates that some state regulations do not allow for the use of high-bleed controllers and concludes that EPA's baseline emissions analysis was likely skewed high.

**Response I-10-54:** See section IV.D.1.b. ii of the December 2022 Supplemental Proposal preamble (87 FR 74761-74766) for response to this comment. Also see sections XI.D.2 and 3 of the preamble to the final rule for discussion of the BSER analysis conducted for the final rule.

### ***10.9.4 Impact of Rule on Small Businesses***

**Comment:** Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) asserts that EPA has underestimated the overall number of affected facilities and particularly the potential impact on small businesses. The commenter reports that the requirement to use zero-bleed pneumatic controllers at existing and modified operations will result in many facilities being forced into replacing functioning equipment with a much more costly alternative, with the potential for insufficient zero-bleed pneumatic controller supplies. In addition, the commenter states that on-site power generation using a combustion of

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<sup>59</sup> The revised capital cost estimate relies on the average of a \$2,000 (EPA's 2016 estimate) and \$5,800 (API's 2016 estimate) expenditure—both of which are included in EPA's 2016 calculations—and is adjusted from 2012 to annualized 2019 dollars using the same price deflator (12.3 percent) and capital recovery factor (.1424) that EPA used in its 2021 TSD. This cost is compared to avoided emissions of 9.2 scf/hr for two intermittent vent controllers at a site (see TSD Table 8-3).

gas could result in the need for additional authorizations, testing, and monitoring of generation equipment and emissions from this equipment.

Response I-10-55: The EPA agrees that switching from natural gas-emitting process controllers to a system that results in zero-emissions from process controllers will require capital expenditures. However, in the revised BSER analysis conducted for the December 2022 Supplemental Proposal and in the refreshed analysis conducted for the final rule, zero emissions from process controllers was shown to be technically achievable and cost-effective at all existing source model plant configurations (outside of Alaska) through several available options. As such, the EPA determined that zero emissions represents the BSER and is the basis for the requirements of the NSPS and EG. For further details regarding the revised BSER analyses, see sections IV.D.1.b. ii and iii of the December 2022 Supplemental Proposal preamble (87 FR 74760-74766) and sections XI. D.2 and 3 of the preamble to the final rule. In addition, pursuant to section 603 of the RFA, EPA prepared an IRFA that examined the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the 2022 RIA (see section 4.3).

Comment: Commenter (0924-SBA) asserts that EPA overstates the support that other regulatory regimes provide for the November 2021 Proposal, particularly with respect to impacts on small businesses. The commenter notes that EPA cites to California, Colorado, New Mexico, and the Canadian provinces of Alberta and British Colombia as evidence that the November 2021 Proposal is reasonable and that there are no technical barriers. However, the commenter provides that, as the description of these regulatory regimes' notes, none of these regimes require universal retrofit of existing sources. California allows some continuous bleed natural gas-driven pneumatic controllers to remain, Colorado has a small operators exemption, New Mexico's proposed rule does not require zero-emitting controllers if there is no electrical power, Alberta only requires zero-emitting for a subset of existing controllers, and British Columbia's rule only requires new sources to be non-emitting. No other regulatory regime applies to all new sources and all existing sources.

Response I-10-56: The EPA agrees that these programs have more exemptions than the EG for existing sources. However, in the revised BSER analysis conducted for the December 2022 Supplemental Proposal and in the refreshed analysis conducted for the final rule, zero emissions from process controllers was shown to be technically achievable and cost-effective at all existing source model plant configurations (outside of Alaska) through several available options. As such, the EPA determined that zero emissions represents the BSER and is the basis for the requirements of the NSPS and EG. For further details regarding the revised BSER analyses, see sections IV.D.1.b. ii and iii of the December 2022 Supplemental Proposal preamble (87 FR 74760-74766) and sections XI. D.2 and 3 of the preamble to the final rule.

Comment: Commenter (0749-PAW) recommends that EPA consider subsidies or grant programs for smaller companies should retrofitting be required for existing sites.

Response I-10-57: This comment on recommended funding programs for small companies is outside the scope of this rulemaking; as such, no response is required.



Comment: Commenter (0924-SBA) recommends that there be a hardship extension of compliance deadline for Small Entities. The commenter requests that EPA provide flexibilities in implementing pneumatic controller requirements for those circumstances in which small entities cannot obtain and/or retrofit zero-emitting controllers. In addition, the commenter requests that EPA allow states to grant extensions to small entities that can show a good faith effort to procure non-emitting controllers at a reasonable price.

Response I-10-58: Similar comments on the implementation timeline of the EG were provided on the December 2022 Supplemental Proposal. For response to this comment, please see Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), and 7.5 (Applicability and Compliance Date Considerations) Responses II-7-80, II-7-81, and II-7-82.

## **10.10 Phase-In of Requirements Under EG OOOOc**

Comment: Several commenters (0215-Evangelical Environmental Network (EEN), 0844-EDF *et al.*, 0918-COLGC) support the proposed 2 years from state plan submission for adoption of emission guidelines for implementation of the zero-emitting pneumatic controller requirements (*i.e.*, existing sources should be required to retrofit within two years of the state plan submission deadline). Commenter (0844-EDF *et al.*) notes that natural gas producer EQT Corporation has reported that they will complete a full retrofit within two years, and Diamondback anticipates it will have replaced “nearly all” of its controllers with zero-emitting devices within four years. Further, the commenter notes that the finalized rule will signal to suppliers the need to ramp up production well in advance of the retrofit deadline, increasing the likelihood of sufficient market availability for suppliers by that time.

Several other commenters (0727-OSEE/ODEQ, 0749-PAW, 0807-BP America, Inc. (BP), 0924-SBA, 1341-Conventional Groups) indicate support for a phased-in approach of greater than two years for implementation of the requirements. The commenters cite the need for operators to address higher production or scheduled upgrade facilities first and that to retrofit all existing sources at the same time will place a substantial economic burden on operators as well as a substantial burden on supply chain and vendors.

Another commenter (0807-BP) indicates that they are already implementing a phase-in program. The commenter notes that they have invested over \$100 million of an initial \$300 million portfolio-wide infrastructure investment to build out electrical infrastructure and substations to power their operations in the Permian. The commenter notes that they anticipate over 75 percent of the companies’ operated wells in the Permian will be electrified by the end of 2022 and over 95 percent by 2023. Where they can electrify, they will install instrument air devices. Based on their experience, they encourage EPA to propose a phase-in approach to equipment retrofits so that operators can prioritize and implement retrofits over a reasonable time horizon.

Commenter (0765-ICAC) states that the transition will need to factor in the time and resources involved in retrofitting existing installations and EPA must ensure that timeframes are safe, realistic, and achievable.

Several commenters (0807-BP, 0817-GPA, 1267-CA AG *et al.*) request the adoption of a phase-in approach that is consistent with Colorado and New Mexico requirements where Colorado requires compliance of 40 percent of the sources within two years and 100 percent within four years.

Commenter (0463-Southern Ute Indian Tribe, Colorado) recommends EPA consider allowing a phased approach, with a final compliance deadline of at least 2 years from the date of rule promulgation, where a portion of an operator's facilities must comply within and extended timeframe (*i.e.*, 50 percent of facilities in compliance within 2 years and 100 percent of facilities in compliance within 4 years).

Other commenters recommended various other phase-in timeframes and implementation dates. Some commenters (0743-WEA, 0831-AXPC) recommend a phase-in period of at least 3 years for new and modified facilities to install equipment required to meet a non-emitting standard. Commenter (0743-WEA) recommends a longer period of 5-7 years for existing facilities to retrofit equipment with low-bleed, intermittent bleed, or non-emitting controllers while another commenter (0831-AXPC) states that, at a minimum, EPA should grant additional implementation time considering the global supply chain challenges that are already challenging an operator's ability to secure components.

Commenter (0817-GPA) notes several factors requiring additional implementation time for retrofitting existing sources:

- Retrofitting pneumatic controllers requires a retrofit of other equipment on the instrument gas/ fuel gas system, including pumps.
- Operators will require time for extensive engineering, reliability studies, and retrofitting across multiple sites—up to hundreds for some operators—at widely dispersed, and often remote locations, around the country.
- For the retrofit project, entire facilities need to be retrofitted to accommodate new automation and backup systems which would likely involve shutting down the facility for installation. The commenter further noted timeframe issues (many of which are beyond the source's control) such as time for permit amendments, potential need to purchase land, and uncertainty with land acquisitions and permitting process. The commenter noted that permit revisions alone could take up to two years.

Commenters (0808-API, 0817-GPA, 0938-TXOGA) recommend a minimum of 5 years citing the recent proposed rulemaking in New Mexico that currently employs an eight-year phase in period for existing sources as the state recognized the complexity of replacing these emission sources. Commenter (0938-TXOGA) states that EPA needs to provide sufficient flexibility for states to develop their plans as states will be closest to the issues in their location and best able to determine appropriate compliance time frames. Commenter (0808-API) notes that one retrofit project can take upwards of 4 months to complete from initial planning to full implementation. The commenter adds that there is a 3-year phase-in precedent that has been established for the oil and gas sector which they believe is the minimum timing required for an appropriate phase-in of retrofit requirements. However, this commenter believes that a more appropriate time period

would be 5 years from the finalized rules/guidelines. Another commenter (0911-NDPC) recommends a minimum of 5 years from rule finalization.

Commenter (0807-BP) recommends that a well-designed phase-in program include an ambitious yet realistic time horizon to achieve 100 percent zero emitting devices; a tiered approach that adjusts for operators that are further ahead on existing retrofits; and an exemption program for the rare circumstance where, for safety reasons, an operator must continue to operate an emitting device.

Response I-10-59: Similar comments on the implementation timeline of the EG were provided on the December 2022 Supplemental Proposal. For response to this comment, please see Volume II, Chapter 7 (Process Controllers), subsection 7.4 (Low Production/Small Sites), and 7.5 (Applicability and Compliance Date Considerations) Responses II-7-80 and II-7-82.

## **10.11 Other**

### ***10.11.1 Supply Chain Issues***

Comment: Commenter (0765-Institute of Clean Air Companies (ICAC)) states that the technologies to implement this exist today and are well-vetted. The commenter explains that there are companies specializing in replacing natural gas-driven pneumatics with air-driven pneumatics operating today. The commenter adds that the transition will need to factor in the time and resources involved in retrofitting existing installations and they request that EPA ensure that timeframes are safe, realistic, and achievable.

Response I-10-60: The EPA agrees that there are several zero-emitting technologies available. See also Response I-10-67 of this Chapter.

Comment: Several commenters (0739-Citation Oil & Gas Corp. (Citation), 0814-IPAA *et al.*, 0938-TXOGA) predict that the pneumatic controller requirements will likely generate an immediate and significant increased demand for zero bleed equipment (*i.e.*, solar powered/battery backup systems, and electric, self-contained systems) and will result in supply chain shortages and limited availability. Commenter (0924-SBA) notes that EPA would be requiring the replacement of over 1.7 million controllers over a few short years. Commenters state that it is unclear that the industry will be able to procure that many that quickly and there is concern that small businesses will have the hardest time procuring non-emitting controllers and will have to pay more for those it can procure. Commenters (0743-WEA, 0938-TXOGA) state that EPA has not adequately considered the impacts of the current supply chain interruptions on the ability of operators to comply with the rule. Specialized equipment, such as air compressors, electric controllers, and equipment needed to retrofit facilities have been particularly hard-hit by supply chain constraints related to COVID-19. Commenter (0743-WEA) reports that owners and operators have already experienced delays of several months in acquiring equipment to retrofit facilities to instrument air, all prior to the November 2021 Proposal, and that the increased demand for that equipment given proposed rule requirements would only exacerbate the challenges associated with acquiring that equipment. Another commenter (0739-Citation) requests that EPA provide supporting data demonstrating this technology is widely available.

Commenter (0808-API) states that many solar system packages in use do not feature turnkey solutions available for mass installation and implementation. The commenter explains that technology provided by certain vendors was referenced in the Carbon Limits study published in 2016<sup>60</sup>, which EPA relied upon in its cost effectiveness analysis. Industry representatives reached out to at least one of the vendors within the last six months to find out how much deployment there has been of these solar systems and electric controllers. The commenter reports that the vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs. Currently, the commenter states that the vendor projects it can only service approximately 200 installs per year.<sup>61</sup> Additionally, the commenter notes that operators are already experiencing 6 to 12-month lead times for solar packages. The commenter concludes by stating that the proposed rules will only exacerbate demand, increase costs, and increase pressure on the supply chain.

Response I-10-61: To address potential delays in the availability of equipment necessary to meet the zero-emissions standards, the EPA is extending the zero-emissions requirements compliance date for the NSPS by one year. Until that date, sites that would otherwise be required to meet the zero-emissions standard must comply with the standards for sites that do not have access to electricity and are located in Alaska. See section XI.D.4 of the final rule preamble for further discussion of this issue and the extended compliance date.

For existing sources, each state must submit a plan to the EPA that establishes standards of performance for each designated facility. For purposes of EG OOOOc, the EPA is finalizing a requirement that each state adopt and submit their state plans incorporating the process controller requirements within 24 months after publication of the final EG OOOOc. The EPA is also finalizing a timeline for compliance with the requirements included in the state plans of 36 months from the deadline for state plan submittals. The combined time allotted for compliance then is 60 months, or 5 years from the publication date of EG OOOOc. This period of time should provide all operators with ample opportunity to determine a compliance strategy and procure and install the necessary equipment.

#### ***10.11.2 Funding for Equipment Replacement at New and Existing Facilities***

Comment: Commenter (0940-Responsible Drilling Alliance (RDA)) states that it is extremely frustrating that a significant portion of emissions from the gas and oil sector is attributed to outdated equipment which operators could detect and fix through cost-effectively replacement with zero-emitting technologies. The commenter suggests that there is a need for Congress to push for the inclusion of a small methane emission fee in currently proposed legislation to set up a fund for operators to borrow, at zero interest, monies necessary for the purchase, installation, and most effective monitoring of zero-emitting pneumatic controllers at both new and existing facilities.

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<sup>60</sup> Carbon Limits. Zero emission technologies for pneumatic controllers in the USA. August 2016

<sup>61</sup> Joint Industry Work Group comments submitted to CDPHE

<https://drive.google.com/drive/folders/1yXOXLue7DqPFutxbq6SeThCMhc5S7DU>

Response I-10-62: This comment on recommended Congressional actions is outside the scope of this rulemaking; as such, no response is required.

### ***10.11.3 Recordkeeping Requirements***

Comment: Commenter (0817-GPA) states that the November 2021 Proposal preamble states that, even though “these ‘zero-emissions controllers’ would not technically be affected facilities because they are not driven by natural gas ... or because they do not vent to the atmosphere, owners and operators should maintain documentation if they would like to be able to demonstrate to permit writers or enforcement officials that there are no methane or VOC emissions from the controllers and that these controllers are not affected facilities subject to the rule.” 86 Fed. Reg. at 63,202. The commenter indicates concern that there is no proposed regulatory language describing what type of documentation would be required and the November 2021 Proposal preamble provides no further summary of what documentation could be needed for compliance purposes. Further, the commenter notes that the November 2021 Proposal provides no explanation of EPA’s authority to require such documentation. The November 2021 Proposal states that zero emission controllers are not affected facilities as they are no longer driven by natural gas. The commenter states that owners and operators would still be required to demonstrate that controllers are zero emission in the case of inspection, but EPA should not dictate the type of documentation required or seek to impose extensive recordkeeping requirements. The commenter reports that operators do not typically keep detailed records of pneumatic controller model types, installation dates, or maintenance events as they are relatively low-cost equipment and not subject to the same recordkeeping practices as equipment requiring capital expenditures. The commenter urges EPA not to issue regulations requiring the maintenance of any particular type of documentation as such regulations would not be permitted as a matter of law and would add unnecessary administrative burdens to operators.

Response I-10-63: As discussed in section XI.D.5 of the final rule preamble, after considering this comment and similar comments received on the December 2022 Supplemental Proposal, we have determined that it is appropriate in this instance to require identification of the equipment that is included in the affected facility, rather than the equipment that is not part of the affected facility. The process controllers included in the affected facility are those that are subject to the emissions standards, whereas process controllers not included in the affected facility are not subject to the emissions standards in the final rule, and also have no potential to emit methane or VOCs. Therefore, we have revised the recordkeeping requirements to require identification only of controllers that meet the finalized definition of an affected facility, which are those process controllers that are driven by natural gas and that are not ESDs.

### ***10.11.4 Effect on Other Industrial Segments***

Comment: Commenter (0922-National Association of Manufacturers (NAM)) expresses concern that because there were 2012 and 2015-2016 rules addressing VOCs and methane it appears that there is an unintended meshing of the lines between existing sources and new sources when an existing source has low bleed pneumatic controllers that might be reclassified as new sources with a zero bleed or zero emissions limit. The commenter argues that the NSPS program was never designed to conflate the lines between new and existing sources. In this case, the

commenter defers to the companies with existing source pneumatic controllers that might be moved into “new” source category when those low bleed pneumatic controllers were installed after the 2016 rule. While this might be something completely isolated to the oil and gas segment because of the industry’s 2012-2016 VOC and methane rules, the commenter requests that EPA clarify so that CAA section 111 rules for other industrial segments do not misinterpret the lines between new and modified and existing sources.

Response I-10-64: See discussion in sections III.B and III.C of the December 2022 Supplemental Proposal preamble regarding the categorization of “new” and “existing” based on the date of construction, modification, and reconstruction for the source category as a whole and section IV.D.1.b.i of the December 2022 Supplemental Proposal preamble for discussion of modification reconstruction for process controllers specifically. See 87 FR 74715-74716 and 74756-74760. See also section XI.D.6 of the final rule preamble for further information regarding modification and reconstruction.

## Chapter 11. Pneumatic Pumps

### 11.1 General Support/Opposition for Proposed Pneumatic Pump Standards

Comment: Several commenters (0844-Environmental Defense Fund (EDF) *et al.*, 0444-Damascus Citizens for Sustainability (DCS), 0781-National Tribal Air Association (NTAA), 0605-Muscogee (Creek) Nation, 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 0391-Keweenaw Bay Indian Community (KBIC), 0770-Northern Plains Resource Council (NPRC), 0437-New York Office of the State Comptroller (NYOSC), 0808-American Petroleum Institute (API)) support the proposed requirements for new and existing pneumatic pumps.

Commenters (0844-EDF *et al.*, 0770-NPRC) encourage EPA to include in its final rule a requirement that operators use zero-emitting technology for pneumatic pumps across the source category. However, if it [the standard] includes a functional need exemption, the commenters suggest that the exemption's design mirror that of pneumatic controllers. The commenters state that electricity is often readily available at compressor stations, large production sites, and sites near urban areas and is becoming increasingly available at other sites. In addition, solar [-powered] pumps are available and have become widespread over the past five years, and for sites with high demand, thermal electric generators or methanol fuel cells have been used to increase power.<sup>1</sup> The commenters contend that the application of a zero-emitting standard in other jurisdictions and the widespread use of non-emitting pumps by oil and gas operators is further evidence of the feasibility of a zero-emissions standard. The commenters note that Alberta and California currently require zero-emitting new and existing pumps, and New Mexico has proposed a rule requiring zero-emitting pumps at all processing plants and at wellhead sites, gathering and boosting sites, and transmission compressor stations with electricity.<sup>2</sup> Moreover, the commenters state that EOG Resources, which operates throughout the U.S., has started an initiative to "[convert] pneumatic pumps to electric or solar power."<sup>3</sup>

At the very least, the commenters recommend that EPA require zero-emitting pumps at sites that are transitioning to zero-emitting pneumatic controllers (on their own or because of the new standards). According to the commenters, operators who install systems that can operate zero-emitting controllers should easily be able to scale those systems to operate zero-emitting pump equipment as well. For both electric and instrument air systems, the commenters report that converting pneumatic pumps to zero-bleed alongside pneumatic controllers adds to overall capital costs, but this is more than made up for by emission reductions which result in an overall decline in abatement costs. The Carbon Limits model supports requiring a zero-emission standard for pumps at sites installing zero-emitting controllers. The commenters state that it demonstrates that both new and existing sites<sup>4</sup> that convert controllers and convert a pump to

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<sup>1</sup> Carbon Limits 2016 at 13, 16.

<sup>2</sup> New Mexico (NM) proposed rule, 20.2.50.122(B)(5).

<sup>3</sup> EOG Resources, 2019 Sustainability Report 6 (2019) [https://eogresources-com.s3-us-west-2.amazonaws.com/EOG\\_2019\\_Sustainability\\_Report.pdf](https://eogresources-com.s3-us-west-2.amazonaws.com/EOG_2019_Sustainability_Report.pdf).

<sup>4</sup> Carbon Limits 2016 at 25.

electric <sup>5</sup> have lower abatement costs than sites that only convert controllers.<sup>6</sup> The report notes the net benefit to operators arises because pumps typically emit more per device than controllers.

Though EPA's own analyses show zero-emitting pumps are cost-effective as is, the commenters encourage EPA to consider the costs of controllers and pumps together, as that further improves cost-effectiveness. As the Carbon Limits model shows, sites with controllers that also have one pump that converts to electric power have a much lower abatement cost than sites without such a pump.<sup>7</sup>

Response I-11-1: In the final NSPS and EG, the EPA is requiring that there be zero emissions from pumps located at sites meeting certain conditions, which are those that have access to electrical power and those that do not have access to electrical power that have three or more natural gas-driven diaphragm pumps. At these sites, all pumps in the pumps affected source are required to meet this standard, which includes piston pumps and pumps in the transmission and storage segment. See section XI.E.1 of the final rule preamble for more information on the EPA's BSER analysis and the final emissions standards for pumps.

Regarding the consideration of costs for zero-emitting pumps and controllers together, the EPA acknowledges that some sites may use common equipment for the control of emissions from both pumps and process controllers, such as a compressed air system. However, sites may also use a different compliance method for these types of equipment, such as using solar-powered electric pumps but a compressed air system for its controllers. As it is not necessary for sites to choose the same method of compliance for both equipment types, the EPA determined that it would not be reasonable to assess the BSER on the basis of both equipment types together. However, the EPA notes that even when assessed individually, the analyses show that there are zero-emissions options that are cost-effective for most sites.

## **11.2 Limitations of Use of Solar-Powered Pumps and Solar Generation**

Comment: Commenter (0793-Permian Basin Petroleum Association (PBPA)) states that onsite solar generation paired with battery storage as an alternative to grid electricity systems are currently uncommon and unreliable. According to the commenter, use of these systems would likely increase the frequency of facility upsets, which would increase safety risks such as overpressure events and spills. The commenter concludes that onsite solar should therefore not be deemed an available technology. Moreover, they add that EPA has not explained how onsite power generation is a viable alternative to grid-electricity in states whose electricity regulations may restrict the ability to setup such onsite generation. For example, the commenter notes that an onsite solar installation may be subject to public utility commission regulation, which would complicate the ability of an upstream operator to sell power to itself. Other commenters (0765-Institute of Clean Air Companies (ICAC)) provide specific examples of where pneumatic pumps not driven by natural gas, particularly solar-powered pumps, would likely not be technically

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<sup>5</sup> Carbon Limits 2016 at 23.

<sup>6</sup> Carbon Limits 2016, 26-27.

<sup>7</sup> Carbon Limits 2016 at 26.



feasible. Some examples of the situations cited include locations with very cold temperatures, extended periods of cloud cover, and heavy snow load.

Response I-11-2: See discussion in section IV.E.1.b.ii. of the supplemental proposal See 87 FR 74775.

### **11.3 Sub-Categorization Based on Access to Electrical Grid**

Comment: Several commenters (0817-GPA Midstream Association (GPA), 0463-Southern Ute Indian Tribe, Colorado, 0844-EDF *et al.*, 0765-ICAC, 0823-Qnergy, 0838-TRIDO Solutions LLC (TRIDO)) support the approach of subcategorizing based on access to electrical power, and then determining BSER for pneumatic pumps separately for sites with and without access to electrical power. One of these commenters (0938-Texas Oil & Gas Association (TXOGA)) notes that the availability of electricity is a significant and constraining factor that is within EPA's authority to consider in subcategorization.

Commenter (0817-GPA) states that they oppose the November 2021 Proposal to extend the zero-emission requirement for pneumatic pumps to gathering and boosting compressor stations. However, the commenter notes that, if EPA determines that electric pumps constitute the BSER, they support EPA's proposal to sub-categorize gathering and boosting compressor stations that lack access to electricity. The commenter further notes that natural gas-driven pneumatic pumps are used minimally at gathering and boosting stations, such as to transfer liquids, or in a temporary capacity. Due to this limited use, the relatively low number of pumps used at compressor stations, and the high cost of implementing a zero-emission standard, the commenter states that the proposed requirement is not cost effective. According to the commenter, the November 2021 Proposal provides little justification for requiring a zero-emission standard at gathering and boosting stations other than to claim that the 2021 U.S. Greenhouse Gas Inventory (GHGI) estimates that these compressor stations emit approximately 26,000 tons of methane. 86 Fed. Reg. at 63,226. The commenter believes this estimate is inaccurate and overstated as operators may overestimate their reports by assuming that pneumatic pumps emit 24 hours per day, seven days a week. Methane emission reductions achieved by a zero-emission standard would, therefore, be a small fraction of EPA's estimate and would not justify the very high costs associated with implementing a zero-emission standard. Electric pumps have lower performance and reliability and would require an electric power supply. Likewise, using solar power where a site lacks access to electricity is impractical, more expensive than EPA estimates, and involves significant maintenance and other concerns. Solar powered pumps are not technically feasible, and the use of electric pumps in general is not technically feasible without the use of an on-site generator. For these reasons, the commenter supports the proposal to sub-categorize sites that lack access to electricity in a manner similar to New Mexico regulations. See 86 Fed. Reg. at 63,227.

Commenter (0463-Southern Ute Indian Tribe, Colorado) provides support for the use of non-natural gas driven pumps as an option at sites where it is technically feasible indicate that requiring these pumps at many of their remote sites would be "burdensome at best and would force site shutdown in many cases."

Commenters (0844-EDF *et al.*, 0765-ICAC) report that options that do not use natural gas-driven pneumatic pumps are available at sites without access to grid electricity systems, and that their use has become widespread over the last five years. One of these commenters (0844-EDF *et al.*) notes that in addition to solar-powered pumps, thermal electric generators or methanol fuel cells have been used to increase power at sites with high demand. Another commenter (0765-ICAC) notes that they are aware of retrofits at remote locations that have no electrical power in which natural gas is used to generate electricity to run controls directly or to power air compressors that drive pneumatic controls.

Commenters (0823-Qnergy, 0838-TRIDO), are equipment vendors and confirm the successful implementation of technologies to utilize pneumatic pumps not driven by natural gas at remote locations without the access to the grid. Commenter (0838-TRIDO) reports that they have deployed solar-driven pneumatic pumps and air compressors in many states throughout the southwestern and northwestern U.S., including a remote location in Wyoming that experienced temperatures down to minus 11 degrees Centigrade (°C). The other vendor (0823-Qnergy) reported that their standalone power generators have been deployed at several sites across the country to power pneumatic pumps. The commenter states that their systems can work on and off the grid and with both renewable and nonrenewable energy sources.<sup>8</sup> They add that all their systems can be connected either to their generators (which are the most reliable power source available on site) or to any other source of power (including grid power), when it exists. According to the commenter, this technology is reasonably affordable and already has been deployed at several sites across the country.

Response I-11-3: See discussion in section IV.E.1.b.ii. of the supplemental proposal. See 87 FR 74772 and 74774-74775. See also the discussion in section XI.E.1 of the final rule preamble for a discussion of the final BSER determination.

## **11.4 Exceptions of Exemptions**

Comment: Commenter (0808-API) provides that, as they noted in their December 4, 2015<sup>9</sup> comments on the proposed NSPS OOOOa<sup>10</sup> there are numerous implications for routing a piston pump to a control device or vapor recovery unit (VRU) and they continue to support EPA in excluding piston pumps from emission guidelines (EG) OOOOc.

Response I-11-4: The commenter's December 4, 2015, remarks regarding piston pumps included concerns that the EPA assumed an equal number of piston pumps and diaphragm pumps exist per site and that the control of piston pumps is not cost-effective. As discussed further in the final rule preamble section XI.E.1, the EPA found that for sites with access to electrical power and for sites without access to electrical power that have at least three natural gas-driven diaphragm pumps, it becomes cost-effective for certain zero-emissions compliance methods to be used for all pumps in the pumps affected source, including both piston pumps and diaphragm pumps. In addition, in a sensitivity analysis performed for the final rule, the EPA found that it is still cost-effective for piston pumps to be controlled when they outnumber diaphragm pumps 3 to 1 (i.e.,

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<sup>8</sup> Note that the "CAP3G" configuration is the variation of this technology capable of being powered by the grid.

<sup>9</sup> API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776).

<sup>10</sup> <https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-6884>.

10 piston pumps and 3 diaphragm pumps). As the EPA determined that zero-emissions compliance methods for pumps have been adequately demonstrated and at least some are cost-effective means of attaining zero-emissions, the BSER for pumps affected sources at sites with access to electrical power and for sites without access to electrical power that have at least three natural gas-driven diaphragm pumps is zero emissions.

Comment: Commenter (0844-EDF *et al.*) requests that if zero-emitting technology is not feasible for an operator, EPA should require that the operator reduce emissions by 95 percent and submit justification for an exemption in its annual report. Further the commenter states that if EPA includes a feasibility exemption, it should require standards for pumps that closely resemble our suggested standards for pneumatic controllers. That is, EPA should require that operators first attempt to reduce emissions by at least 95 percent, with a preference for routing emissions to a VRU rather than to a combustion device. If that level of control is not feasible, the commenter recommends that operators be required to reduce emissions to the greatest extent possible. In these instances, they suggest that operators be required to provide a functional need justification in their annual report, including documentation as to: (1) why power (either grid-based or solar) is unavailable; (2) if applicable and the operator isn't achieving 95 percent reductions, why reducing emissions by 95 percent is infeasible; and (3) how the operator plans to reduce emissions from their pneumatic pumps to the maximum extent possible.

Response I-11-5: As discussed further in the final rule preamble in section XI.E.1, the final rule requirements for pumps have been revised from the November 2021 Proposal and the December 2022 Supplemental Proposal. The EPA determined it was possible to specify the conditions under which the different pump requirements apply in the NSPS and EG that reflect the BSER and that eliminate the need for demonstrations of technical infeasibility. The analyses for BSER show there are technically feasible zero-emission options, which can be implemented at costs the EPA considers reasonable at sites with access to electricity and at sites without electricity that have three or more natural gas-driven diaphragm pumps. Routing emissions to a process is included as a zero-emissions option, as the EPA recognizes that with proper equipment operation, this option will result in zero emissions from pumps. Sites without electricity and with fewer than three natural gas-driven diaphragm pumps may use zero emissions options or may reduce emissions using existing control devices. At these sites, if a VRU is not onsite to route emissions through to a process, or if no emissions control device is onsite, pump emissions are not required to be reduced. These requirements reflect the BSER determinations regarding emissions reductions, costs, and other impacts.

Comment: Commenter (0789-Pennsylvania Department of Environmental Protection (PDEP)) states that Pennsylvania currently requires emission reductions of 95 percent or greater for all natural gas-driven pneumatic pumps at natural gas well sites, natural gas compressors, and natural gas processing and transmission plants when the methane emission rate is 200 tons per year (tpy) or greater, the volatile organic compound (VOC) emission rate is 2.7 tpy or greater, any specific hazardous air pollutant (HAP) has an emission rate of 0.5 tpy or greater, or when the total of all HAP emissions is 1.0 tpy or greater. Given this, the commenter recommends the EPA consider removing the exemption based on availability of existing controls or processes at the site and require 95 percent control of natural gas from all-natural gas-driven pneumatic pumps, regardless of location.

Response I-11-6: While the EPA agrees that the determination of when to require emissions controls could be made based on the potential or actual emissions from an emissions source, the EPA has not revised the regulatory text for pumps in the final rule to require emissions controls based on an explicit emissions threshold. The use of such a regulatory emissions threshold implies that emissions at that level are high enough to justify emissions control requirements based on the emissions reductions that could be realized and the associated costs and other impacts of the controls. To simplify the applicability determination process for the final rule, we determined the emissions levels that would be necessary to justify emissions control requirements and the conditions under which those emissions levels would occur. Thus, we determined in our BSER analysis the site conditions for which control of pumps is reasonable based on the emissions reductions that would be achieved and the costs and other impacts associated with emissions controls. This up-front determination simplifies the applicability process by not requiring owners or operators to determine potential or actual emissions and by not requiring an air quality agency to review that information.

## **11.5 BSER Analysis**

### ***11.5.1 Emissions/Emissions Factors***

Comment: Commenter (0782-Berkshire Hathaway Energy Company (BHE)) states that pneumatic pumps should not be added as a regulated source for the transmission and storage segment. The commenter reports that the prevalence and use of pneumatic pumps at transmission and storage facilities is very minimal, and thus emissions are very low. The commenter adds that this is supported by EPA's decision to not include this source for transmission and storage in EPA's annual greenhouse gas (GHG) inventory. In addition, the commenter notes that EPA excluded gas-driven piston pumps from the 2016 NSPS OOOOa regulations based on their inherently low emission rates.

Commenter (0782-BHE) states that in the November 2021 Proposal Technical Support Document (TSD), it appears that EPA relied on model assumptions for natural gas processing plants (*e.g.*, see November 2021 Proposal TSD Table 9-14 and related discussion). The commenter notes that the November 2021 Proposal TSD presentation estimates 4 to 100 pumps depending on the compressor size. The commenter notes that these numbers are unsupported for transmission and storage, significantly over-estimate transmission and storage pneumatic pump counts, and do not provide representative prevalence or ranges for cost control estimates. Further, the commenter adds that the EPA baseline emissions assumptions presume that natural gas bleeds from the pump 8,760 hours per year, which significantly overstates emissions from two of the more likely applications that may occur in transmission and storage – portable applications and chemical injection. When located at a transmission and storage facility, the commenter reports that these pumps are operated infrequently, and typically used for periodic liquid transfer service, methanol injection to prevent hydrate formation, or injection of corrosion inhibitors.

Commenter (0782-BHE) suggests that EPA not base its analysis for the transmission and storage segment on model plants and pump counts developed for gas processing plants. If EPA considers including requirements for transmission and storage pneumatic pumps, the commenter

recommends using data and analysis representative of transmission and storage facilities to support the inclusion of transmission and storage pneumatic pumps. The commenter supports earlier determinations by EPA (in NSPS OOOOa, in annual GHGI) to exclude pneumatic pumps for transmission and storage sources. The November 2021 Proposal TSD notes that the decision was due to the lack of available information:

However, EPA did not include pneumatic pumps in the transmission and storage segments in the final 2016 NSPS OOOOa because EPA did not have a reliable source of information indicating the prevalence of pneumatic pumps or their emission rates in the transmission and storage segments.

Similarly, the 2016 CTG [Control Technology Guideline] did not recommend controls for pumps in the transmission and storage sector due to a lack of information on the prevalence of pumps in that sector.

Commenter (0782-BHE) contends that the lack of data is due, in large part, to the limited number of pneumatic pumps and limited annual operating time when pumps are present at transmission and storage facilities. While data is unavailable, the commenter discourages EPA from conducting an analysis for transmission and storage based on model plants in gas processing due to the differences in the systems. The commenter recommends excluding this source for transmission and storage, or conducting an analysis based on transmission and storage data and cost estimates to support inclusion.

Response I-11-7: In the final NSPS and EG, the EPA is requiring that there be zero emissions from pumps located at sites meeting certain conditions, which are those that have access to electrical power and those that do not have access to electrical power that have three or more natural gas-driven diaphragm pumps. At these sites, all pumps in the pumps affected source are required to meet this standard, which includes pumps in the transmission and storage segment. See section XI.E.1 of the final rule preamble for more information on the EPA's BSER analysis and the final emissions standards for pumps.

See section VI.E.1.b.ii.C of the December 2022 Supplemental Proposal preamble (87 FR 74777) for discussion of the 90-day exemption for pumps used only temporarily. **11.5.2 Costs**

Comment: Commenter (0844-EDF *et al.*) states that routing to an existing combustion device or VRU are cost-effective solutions for operators who cannot install zero-emitting pumps. The commenter adds that EPA's costs for routing to a new combustion device and VRU are higher. However, they believe EPA's VRU calculations overestimate costs. As a result, the commenter suggests that EPA reconsider its VRU cost calculations for the final rule.

The commenter (0844-EDF *et al.*) continues that EPA's decision to base its cost analysis for VRUs in the November 2021 Proposal on 2016 estimates is inherently flawed and arbitrary for several reasons. First, those values are outdated, and it's unclear how representative they are. EPA did not explain how it vetted the asserted capital cost increases before accepting them and including them in their final rule. Second, the 2016 cost estimate assumed a \$7,000 (2012 U.S. Dollars) component to account for 200 feet of piping. This accounts for over 80 percent of the

included cost estimate. The commenter contends that this is problematic because few sites will need such a large length of piping. As a result, this heightened cost doesn't apply to a significant number of sites governed by the November 2021 Proposal. The commenter urges the EPA to reconsider its 2016 and 2021 calculations for VRU cost-effectiveness, especially for routing to a new VRU. The commenter recommends that EPA conduct a cost analysis based on more reliable inputs.

Response I-11-8: NSPS OOOOa at §60.5393a(b) requires that natural gas-driven diaphragm pumps at well sites must reduce natural gas emissions by 95% if a control device is onsite and must route those pump emissions to another control device if the only control device(s) at the site achieve less than 95% emissions reductions. If no control device is onsite, OOOOa does not require emissions reductions from pumps. For the December 2022 Supplemental Proposal, we re-evaluated pump options that would result in zero emissions of methane and VOC, and we also evaluated the use of new and existing control devices in our analysis. For the final rule, we have updated the analysis performed for the December 2022 Supplemental Proposal to include more recent cost information for pump zero-emissions options and we also updated our analysis for control of emissions by routing emissions to a process through a new or existing VRU and a new or existing combustion control device. For both the supplemental proposal and the final rule, our analyses showed that zero emissions represents the BSER at sites with certain characteristics, including having access to electricity at the site and having a certain number of diaphragm pumps at the site. The analysis conducted for the final rule using the updated information shows that costs to achieve zero emissions from pumps are reasonable when there is access to electricity and when there are three or more diaphragm pumps at a site without electricity. For sites with access to electricity and for sites without electricity that have three or more natural gas-driven diaphragm pumps, 95% control was not determined to be the BSER and was not used to develop the pump standards for the NSPS or the presumptive standards for the EG. Zero emissions from pumps was shown in our analyses to be technically achievable and cost-effective through several available options, including the use of electrical pumps powered by electricity from the grid or solar power systems, pumps powered by compressed air using electricity from the grid, and by routing emissions to a process. For sites without electricity and with fewer than three natural gas-driven diaphragm pumps, our analysis for the final rule shows that control of emissions through a control device otherwise onsite represents the BSER. At these sites, requiring zero emissions from pumps, requiring the use of a new control device, and requiring the routing of pump emissions to a process through a new vapor recovery unit (VRU) (which is usually required to attain the necessary pressure for the gas to enter a process onsite) does not represent the BSER due to the costs associated with the equipment needed for these options. The NSPS and the EG for these sites reflect the BSER determination by requiring that emissions be routed to a process through a VRU if a VRU is onsite; if a VRU is not onsite, pump emissions are required to be routed to a control device onsite that achieves 95% emissions reductions; if no control device that achieves 95% emissions reduction is onsite, another onsite control device may be used; and if no VRU or control device is onsite, pump emissions are not required to be controlled. For existing sites that have access to electrical power or that have three or more diaphragm pumps, owners/operators currently complying with OOOOa by routing emissions to a control device achieving 95% control will be required to switch to a zero-emissions option for pumps to comply with OOOOc. For existing sites that do not have access to electrical power or that have fewer than three natural gas-driven diaphragm pumps, owners/operators currently

complying with OOOOa by routing emissions to a control device achieving 95% control will be required to switch to routing emissions to a process if a VRU is onsite, otherwise, they may continue to route emissions to a control device achieving 95% control for compliance with OOOOc. See section XI.E.1 of the final rule preamble for more information regarding the BSER analysis.

## 11.6 Other

### 11.6.1 Supply Chain Issues

Comment: Commenters (0739-Citation Oil & Gas Corp. (Citation), 0808-API) indicate that the November 2021 Proposal would exacerbate demand, increase costs, and increase pressure on the supply chain for zero-emissions systems. Commenter (0739-Citation) states that reliability and availability of alternate zero-emission options (*i.e.*, solar-powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations. Another commenter (0808-API) indicates that one of their members contacted a vendor within the last six months to find out how much deployment there has been of solar systems and electric controllers. The commenter reports that the vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs, and the vendor estimates that it can only service approximately 200 installs per year. The commenter adds that operators are already experiencing 6 to 12-month lead times for delivery of solar packages.

Commenter (0739-Citation) states that inclusion of previously exempt piston pumps for new and existing sources will result in a significant increased demand for zero emission pumps. Reliability and availability of alternate zero emission options (*i.e.*, solar powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations. If the November 2021 Proposal is finalized, the commenter requests that the EPA provide supporting data demonstrating this technology is widely available and reliable. The commenter is concerned that a hasty conversion to untested technologies could create upset conditions due to failures and result in increases in emissions after significant capital expenditures.

Response I-11-9: See section IV.E.1.b.ii of the December 2022 Supplemental Proposal for discussion of the demonstration of the use of zero-emitting technologies for pumps.

To address potential delays in the available of equipment necessary to meet the zero-emissions standards, the EPA is extending the zero-emissions requirements compliance date for the NSPS by one year. Until that date, sites that would otherwise be required to meet the zero-emissions standard must comply with the standards for sites that do not have access to electricity and have fewer than three natural gas-driven diaphragm pumps. See section XI.E.2 of the final rule preamble for further discussion of this issue and the extended compliance date.

For existing sources, each state must submit a plan to the EPA that establishes standards of performance for each designated facility. For purposes of EG OOOOc, the EPA is finalizing a requirement that each state adopt and submit their state plans incorporating the process controller requirements within 24 months after publication of the final EG OOOOc. The EPA is also

finalizing a timeline for compliance with the requirements included in the state plans of 36 months from the deadline for state plan submittals. The combined time allotted for compliance then is 60 months, or 5 years from the publication date of EG OOOOc. This period of time should provide all operators with ample opportunity to determine a compliance strategy and procure and install the necessary equipment.

#### ***11.6.2 Requirement for Professional Engineer (PE) to Certify Technical Infeasibility***

Comment: Commenters (0923/1376-Lambda Energy Resources LLC (Lambda), 0787/1289-Atmos Energy Corporation (Atmos)) support EPA's November 2021 Proposal to allow in-house engineers to certify facility design and determine situations of technical feasibility. Commenter (0923/1376-Lambda) states that this would align with the 2020 Technical Rule, thereby promoting regulatory consistency, and that an in-house engineer has direct experience with the operating equipment and the relevant site. The commenter states that they are likely to have more knowledge about the site and can therefore apply a higher level of scrutiny to such determinations. Commenter (0755-Texas Pipeline Association (TPA)) supports the November 2021 Proposal to allow in-house engineers to make such certifications. However, the commenter also believes that EPA should expand the universe of persons who could make required certifications and determinations to include non-PE outside personnel such as company-hired contractors or consultants if they have appropriate expertise, *e.g.*, if they have designed the system in question. The commenter contends that this would provide additional flexibility without sacrificing any environmental protections because such third parties would have to have appropriate expertise on design and operation of the system in order to complete a certification or to make a required technical determination.

Response I-11-10: The final rule requirements for pumps have been revised from the November 2021 Proposal and the December 2022 Supplemental Proposal. The EPA determined it was possible to specify the conditions under which the different pump requirements apply in the NSPS and EG that reflect the BSER and that eliminate the need for certified demonstrations of technical infeasibility. The analyses for BSER show there are technically feasible zero-emission options, which can be implemented at costs the EPA considers reasonable at sites with access to electricity and at sites without electricity that have three or more natural gas-driven diaphragm pumps. Routing emissions to a process is included as a zero-emissions option, as the EPA recognizes that with proper equipment operation, this option will result in zero emissions from pumps. Sites without electricity and with fewer than three natural gas-driven diaphragm pumps may use zero emissions options or may reduce emissions using existing control devices. At these sites, if a VRU is not onsite to route emissions through to a process, or if no emissions control device is onsite, pump emissions are not required to be reduced. These requirements reflect the BSER determinations regarding emissions reductions, costs, and other impacts. See also the final rule preamble section XI.E.1 for more discussion of the final BSER analysis.



## Chapter 12. Well Liquids Unloading Operations

### 12.1 Applicability

#### 12.1.1 Modification

##### 12.1.1.1 Support/Opposition to Each Liquids Unloading Event Constituting a Modification

Comment: Commenters (0539-Alaska Oil and Gas Conservation Commission (AOGCC), 0781-National Tribal Air Association (NTAA), 0391-Keweenaw Bay Indian Community (KBIC), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 0605-Muscogee (Creek) Nation) agree, in general, with EPA's November 2021 Proposal that each liquid unloading event represents a modification and therefore, would be subject to the requirements of New Source Performance Standard (NSPS) OOOOb.

Conversely, commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) expresses concern that a well that undergoes liquids unloading for the first time would be subject to NSPS OOOOb without any transition period for a source to come into compliance. The commenter notes that, because sources may need to install control equipment, route emissions to control equipment, install zero emissions controllers, *etc.*, they would need time to design and install this equipment prior to operation. The commenter also suggests that defining well liquids unloading events as a modification would create implementation and compliance confusion (for the state and for the facilities it regulates), assuming only the well is subject to the NSPS, instead of the whole well site, as indicated by EPA. The commenter continues to state that from a state permitting and enforcement perspective, this is problematic and would be very difficult to implement.

The commenter (0424-WVDEP) adds that they believe the November 2021 Proposal would create unproductive work for the states to continually recategorize wells for emissions inventory purposes from designated facilities subject to the Emission Guidelines (EGs) to affected facilities subject to the NSPS in the State Plan development and the state annual reports required by the EGs without additional environmental benefit. Further, the commenter states that it would complicate the permitting process because the source would be required to submit a modification application and obtain a revised permit prior to each unloading event. At a minimum, the commenter requests that vertical wells that use a pump jack to transfer the liquids to storage tank as part of their normal operation not be defined as a modification. The commenter urges the EPA to include the best system of emissions reduction (BSER) for liquid unloading events in the EGs and not define these events as modifications. The commenter suggests that it would be more efficient and less confusing from a practical perspective to include the liquids unloading controls within the EGs rather than have the well subject to the NSPS with the remainder of the facility subject to the EGs.

Commenters (0424-WVDEP, 0577-Kansas Independent Oil & Gas Association (KIOGA), 0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ)) urge EPA to reconsider its determination that each liquids

unloading event represents a modification, making the well subject to new source standards for purposes of liquids unloading standards.

A couple of the commenters (0424-WVDEP, 0577-KIOGA) state that oil and natural gas wells produce the largest volume at the time they are initially drilled; followed by a declining curve over time. The commenters note that, depending on when the liquid unloading event occurs, the production would only return to where it should have been on the declining production curve assuming the liquid unloading event was successful. The commenters stress that the production never increases to the volume the wells observe early in the production curve for a new well, and further state that liquid unloading events are considered normal operation for well operators.

Commenter (0727-OSEE/ODEQ) notes that liquids unloading would be a relatively small event to constitute a modification under Title I of the Clean Air Act (CAA) and thus, it could potentially create unexpected regulatory complexities. The commenter recommends that EPA reconsider its definition of modification to achieve the goals intended without entangling other requirements. Further, the commenter adds that they are concerned that EPA's definition of a modification could set an unwelcome precedent and a significant departure from standard practice under 40 C.F.R. Part 60.

Response I-12-1: Based on comments received on the November 2021 Proposal, the December 2022 Supplemental Proposal for NSPS OOOOb specified that a modification to an existing well occurs when the definition of modification in 40 Code of Federal Regulations (CFR) 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing. The final rule maintains what was proposed in the December 2022 Supplemental Proposal. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and EPA's request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>1</sup> See section 6.4.1 (Applicability) of Volume II of this Response to Comment document (RTC) for comments and responses on the December 2022 Supplemental Proposal on the definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and what constitutes a modification for existing wells for liquids unloading operations.

Comment: Commenters (0599-Marcellus Shale Coalition (MSC), 0793-Permian Basin Petroleum Association (PBPA), 0831-American Exploration and Production Council (AXPC)) argue that liquids unloading activities should not be considered modifications; stating that unloading is not necessarily a physical or operational change – but instead a routine part of initiating flow in the well production process, nor does it result in the potential for increased emissions when wells do not vent. According to the commenters, almost all wells experience liquid unloading during the natural production of the well, many without any equipment modification and as a stage of “primary” production.

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<sup>1</sup> 87 FR 74781-74782, December 6, 2022.

Commenter (0599-MS) adds that even gas wells that do not contain any movable liquids in the formation will generate liquids due to condensation of the liquid vapor in the gas as the gas cools during production from the downhole formation to the surface wellhead. According to the commenter, with time this liquid can accumulate in the wellbore and can temporarily load the well until the well pressure increases naturally under this fluid column until there is sufficient pressure/energy to unload the liquid column.

Moreover, commenter (0793-PBPA) mentions that EPA has historically concluded that both routine maintenance and an increase in production rate of an existing facility (assuming no capital expenditure) are not modifications. The commenter writes, that's presumably why EPA limited wellsite modifications under NSPS OOOOa (for fugitive emissions purposes) to when a new well is drilled at an existing well site and to when a well at an existing well site is hydraulically fractured or refractured. The commenter underscores the point that these are fundamentally different than liquids unloading, which does not involve any change and instead is a routine part of initiating flow in the well production process, but rather akin to the removal of a clog.

According to the commenter (0831-AXPC), there are a number of methods an operator may use based on the engineering needs of the well, and an operator may even need to adjust the method being used over the course of the same day. Nevertheless, the commenter reiterates the point that not all methods for liquids unloading involve the venting of emissions or cause the affected facility to increase its potential to emit.

Commenter (0935-Colorado Oil and Gas Association (COGA)) asserts that EPA's reasoning to treat each unloading event as a modification that makes a well an affected facility subject to the NSPS, on the grounds that each unloading event should be seen as an operational change, is incorrect, because it conflates intermittent activities with operational changes. The commenter explains that oil and gas operations (like other industries) involve numerous intermittent activities – bypassing production to an atmospheric tank is analogous to opening a separator dump valve, starting or stopping an engine, resuming operations after a temporary shut in for maintenance, or any number of intermittent activities. The commenter contends that these activities do not constitute a modification of the facility, and neither does an unloading event.

Commenters (0564-Arkansas Independent Producers and Royalty Owners (AIPRO), 0808-American Petroleum Institute (API)) question what constitutes a “facility modification” and what is triggered by a modification; arguing that the three proposed modifications – *i.e.*, centralized production facilities (CPFs), tanks/tank batteries, and liquids unloading, in the rule do not meet the definition of a modification to a location, because they are activities at a location and not physical changes to the facilities.

Commenter (0564-AIPRO) writes that the action of liquids unloading at a facility is part of the normal operations of the facility and does not constitute a physical change to the method of operations.

Response I-12-2: Based on comments received on the November 2021 Proposal, the December 2022 Supplemental Proposal for NSPS OOOOb specifies that a modification to an existing well

occurs when the definition of modification in 40 CFR 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing. The final rule maintains what was proposed in the December 2022 Supplemental Proposal. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA's request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>2</sup> See Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

Comment: Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) suggests that adding well liquid unloading as a new affected facility creates a situation where companies may need to register and certify operations to demonstrate compliance at sites that were not previously subject to TCEQ registration requirements. According to the commenter, establishing the activity as a trigger for affected facility status creates a scenario where many existing sites that are not subject to NSPS OOOOa or new NSPS OOOOb requirements will become applicable to the NSPS. The commenter adds that the November 2021 Proposal also defines every well unloading operation as a "modification;" however, this does not seem to line up with the legally defined definition of a "modification" under NSPS as a "change in operation." This will create unintended consequences where modification can trigger review under the prevention of significant deterioration (PSD) program.

Response I-12-3: Based on comments received on the November 2021 Proposal, the December 2022 Supplemental Proposal for NSPS OOOOb specifies that a modification to an existing well occurs when the definition of modification in 40 CFR 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA's request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>3</sup> Please also see Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

#### 12.1.1.2 Legal Considerations

Comment: Commenter (0831-AXPC) expresses concern that adopting the approach in the November 2021 Proposal—that a liquids unloading event per se represents a modification of the

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<sup>2</sup> 87 FR 74781-74782.

<sup>3</sup> 87 FR 74781-74782.

affected facility—is not in keeping with the statute. The commenter asserts that the CAA provides that a source undergoes “modification” when it is subject to “any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.” [CAA section 111(a)(4), 42 U.S.C. § 7411(a)(4)] While the commenter supports the use of best management practices (BMPs) as a work practice standard to minimize the methane emissions associated with vented liquids unloading events with some clarifications, an approach under which each unloading event constitutes a modification is in conflict with the statute because liquids unloading is not, per se, either a physical change to the source or a change in its method of operation, nor does it necessarily increase the source’s emissions.

Similarly, commenter (0808-API) contends that the November 2021 proposed definition for liquids unloading poses a legal issue, because liquids unloading is necessary at many wells to achieve the production potential of the given resource. As such, the commenter contends that liquids unloading is part of normal operations for the well and therefore, does not constitute a physical or operational change to that well. Additionally, the commenter argues that because the regulatory definition of “modification” measures an emission increase in terms of the short-term potential to emit of the affected facility, it cannot be said that liquids unloading results in an emissions increase.

Commenter (0808-API) acknowledges that the D.C. Circuit has held that the definition of “modification” should be construed expansively. [*New York v. EPA*, 443 F. 3d 880, 886-7 (D.C. Cir. 2006)]. However, the commenter asserts that the court recognized that even though the term “modification” is broad, it “cannot bring an activity that is never considered a ‘physical change’ in the ordinary usage within the ambit of new source review (NSR),” which the commenter maintains is the case here, with liquids unloading.

Response I-12-4: Based on comments received on the November 2021 Proposal, the December 2022 Supplemental Proposal for NSPS OOOOb proposed that a modification to an existing well occurs when the definition of modification in 40 CFR 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA’s request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>4</sup> Please also see Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

#### 12.1.1.3 Other

Comment: Commenter (0749-Petroleum Association of Wyoming (PAW)) underscores that EPA has not proposed a time component. The commenter asks, “[w]hat if a blowdown event only

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<sup>4</sup> 87 FR 74781-74782.

lasts for 2 minutes, or 60 seconds? Would the same requirements apply as an event that lasts for a longer duration?”

Response I-12-5: The November 2021 Proposal and December 2022 Supplemental Proposal purposefully did not propose a time component for what constitutes a gas well liquids unloading event. The final rule requires owners or operators to minimize or eliminate emissions from liquids unloading operations. Where any venting to the atmosphere occurs as a result of liquids unloading activities, an owner or operator of a well affected/designated facility must employ BMPs to minimize emissions to the maximum extent possible.

### ***12.1.2 Affected Facility Definition***

Comment: Several commenters (0599-MSA, 0727-OSEE/ODEQ, 0743-Western Energy Alliance (WEA), 0763-TCEQ/RRC, 0777-Ascent Resources, LLC (Ascent), 0808-API, 0935-COGA) support the adoption of the November 2021 proposed affected facility Option 2 definition.

Commenter (0831-AXPC) requests that EPA clarify in Option 2 that its liquids unloading requirements would apply specifically to gas wells utilizing venting liquids unloading techniques.

Commenter (0777-Ascent) states that EPA should pursue only Option 2, which would limit the affected facility to those well liquids unloading operations that have associated venting, and thus have emissions to control – a more-appropriate way to define the affected facility for purposes of the proposed rule, according to the commenter. The commenter writes, [if] the purpose of the November 2021 Proposal is to control the emissions associated with well liquids unloading operations, then under Option 2, liquids unloading with no associated emissions would not be impacted by the rule, and thus should not be included in the scope of “affected facility.”

Commenter (0763-TCEQ/RRC) writes, if well liquid unloading is included, they recommend that only those facilities not designed to eliminate venting be considered affected facilities [Option 2], as facilities that have eliminated venting to the atmosphere are not significant sources of methane emissions.

Commenters (0743-WEA, 0808-API) state that, contingent on clarification that liquids unloading requirements are specific to liquids unloading of gas wells that vent emissions to atmosphere, the commenters support EPA’s proposed Option 2. The commenters specifically request (along with commenter 0911-North Dakota Petroleum Council (NDPC)) that EPA clarify within its proposed rule that liquids unloading requirements are *only* applicable to gas wells that vent emissions to atmosphere –consistent with the Technical Support Document (TSD) for liquids unloading. Commenter (0808-API) adds that it was EPA's intent to limit the affected facility for liquids unloading to gas wells only, because EPA's process description in the TSD for liquids unloading mentions only gas wells.

In a similar comment, commenter (0911-NDPC) requests clarification as to if well liquids unloading operations only apply to gas wells as described in 40 CFR 98. Furthermore, the

commenter believes that the EPA should only focus regulations on the liquids unloading operations that result in the venting of natural gas.

Commenter (0935-COGA) states that limiting the rule's applicability to well liquids unloading events with emissions to atmosphere [Option 2] is consistent with the EPA's November 2021 Proposal to limit the applicability of its pneumatic controller standards to each continuous bleed natural gas driven pneumatic controller "that vents to the atmosphere" and to each intermittent bleed controller that "is designed to only release natural gas to the atmosphere as part of the actuation cycle." [86 FR 63202]

Commenter (0599-MSD) supports Option 2 solely for gas wells that vent. According to the commenter, reporting for wells that do not vent is burdensome, with no emission benefit, and too broad in scope. The commenter recommends that [under Option 2], an affected facility be defined as every well that undergoes liquids unloading using a method that vents; adding that wells that utilize non-venting methods would not be affected facilities that are subject to the NSPS OOOOb.

Similarly, several commenters (0599-MSD, 0743-WEA, 0749-PAW, 0935-COGA) specifically oppose the adoption of the November 2021 proposed affected facility Option 1 definition.

Commenter (0749-PAW) writes that non-venting liquids unloading wells should not be affected facilities.

Commenter (0743-WEA) contends that liquids unloading activities and techniques do not contribute in any significant way to methane emissions, and therefore, there is no justification for them to be subject to recordkeeping and reporting requirements as affected facilities. Consistent with this reasoning, the commenter asserts that Option 1 is not technically feasible. According to the commenter, this approach should limit the required recordkeeping and reporting requirements, such as to not duplicate the reporting made by operators under EPA's Greenhouse Gas Reporting Program (GHGRP) Rule, Subpart W.

Commenter (0599-MSD) believes that Option 1 should be eliminated from the proposed rule; arguing nearly all wells experience liquid unloading. The commenter worries that the application of the proposed Option 1 definition would therefore apply to almost all wells, even wells that are still producing naturally without any added artificial lift technology. The commenter contends that this would be an unreasonable recordkeeping request.

Commenter (0935-COGA) argues that the definition of an affected facility for well liquid should not include wells that unload liquids using only non-emitting techniques, as contemplated in EPA's Option 1. [86 FR, 63179 and 63210]. The commenter contends that this definition would unnecessarily regulate facilities with activities that do not emit and implementing this definition would be difficult for routine activities such as plunger lift actuations and the use of soaps, surfactants, velocity strings, or other methods that allow liquids to flow from the well without emissions. The commenter suggests that EPA only regulate activities that cause emissions to atmosphere [Option 2]. As support, the commenter briefly discusses the state of Colorado and their choice, when adopting regulations in response to local conditions, not to regulate non-

emitting events. Moreover, the commenter adds that EPA's Option 1 would require recordkeeping and reporting for no purpose.

Response I-12-6: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and (3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS OOOOb. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA's request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>5</sup> See also Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the proposed definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

In response to the commenter that requested that the EPA clarify in the rule that its liquids unloading requirements apply specifically to "gas wells" utilizing venting liquids unloading techniques. The EPA agrees and confirms that the final rule requirements apply to "gas wells" that unload liquids.

With regards to the commenter that requests that EPA limit recordkeeping and reporting to only liquids unloading activities and techniques that vent emissions and to not duplicate the reporting made by operators under EPA's Greenhouse Gas Reporting Program (GHGRP) Rule, Subpart W, see responses to comments provided in section 12.5 of this Chapter, and section X.F.1 and 3 of the preamble to the final rule which details EPA's final liquids unloading operation standards and associated recordkeeping and reporting requirements.

Comment: Commenters (0391-KBIC, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-Ute EPD, 0844-Environmental Defense Fund (EDF) *et al.*) support minimizing emissions from liquids unloading and the adoption of the Option 1 affected facility definition that defines every well that undergoes liquids unloading as an affected facility.

Commenter (0775/0776-Air Pollution Control Division, Colorado Department of Public Health and Environment (CDPHE)) supports EPA's November 2021 proposed Option 1 affected facility definition as preferable from an administrative tracking perspective and an emissions perspective. The commenter states that unloading activities that use technology designed to eliminate venting, such as plunger lift, sometimes do vent to the atmosphere. Furthermore, the commenter maintains that, under the November 2021 proposed Option 2 definition, a well that uses a plunger lift (that sometimes limits venting but not always) would potentially not be an

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<sup>5</sup> 87 FR 74781-74782.



“affected facility” and, according to the commenter, the times that it does vent would go unrecorded.

Commenter (0844-EDF *et al.*) supports Option 1 of EPA’s November 2021 Proposal, because it is essential that records be kept of liquids unloading events so that the Agency, the public, and operators understand when and why liquids unloading could not be conducted with zero emissions. The commenter briefly defines Option 1 – specifically, how the Agency proposes to define the affected facility as every well that undergoes liquids unloading, meaning that wells utilizing a non-emitting method for liquids unloading would be affected facilities and subject to certain reporting and recordkeeping requirements. The commenter contends that this is a critical requirement to ensure that operators do not claim to conduct liquids unloading events with zero emission techniques, when in reality venting is occurring. The commenter points out that as EPA has recognized, “under some circumstances venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.*, a technology malfunction or operator error).”<sup>6</sup> The commenter continues to write that in some cases, the malfunction or error could be so great that it results in venting 100 percent of the gas intended to be captured. Because of this, the commenter insists that EPA require recordkeeping so it is aware of these events and overall emissions, and to build an understanding of what causes these errors and how they can be prevented. The commenter believes that the EPA should therefore finalize Option 1 and require operators to maintain records of the number of unloading events that occur, the method used, and any venting that occurred.

Response I-12-7: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and (3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS OOOOb. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA’s request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>7</sup> See Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the proposed definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

Comment: Commenters (0599-MSA, 0814-Independent Petroleum Association of America (IPAA) *et al.*, 0831-AXPC) request that EPA focus requirements on liquid unloading events resulting in venting and not the “design” of the liquid unloading method. The “design” of the methods, venting or non-venting, according to the commenter (0599-MSA), is not relevant. The commenter writes that the current GHGRP Rule (*i.e.*, 40 CFR 98 Subpart W) reporting

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<sup>6</sup> 86 FR 63179, November 15, 2021.

<sup>7</sup> 87 FR 74781-74782.

elements, (*i.e.*, gas wells that vent) should be maintained as the basis for a liquid unloading affected facility.

The commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) go on to explain that the design of a well's liquids unloading strategy often can give rise to multiple possible outcomes depending on various factors that can change daily, *e.g.*, operating temperatures and pressures, reservoir behavior, gathering and compression systems, offset well effects. Any attempt to define affected facilities based on whether a well is "designed" to vent during unloading or not, according to the commenters, is problematic because both design possibilities may and often do exist concurrently at a given well. The commenters state that all wells will eventually require liquids unloading at multiple points over the course of their operations, although one cannot necessarily predict when or how many times over the life of the well, nor will it be the same for every well. Similarly, the commenters note that the methods used to unload liquids throughout the life of the well will change depending on the conditions of the well. A method that was, at one point, according to the commenters, successful in routing the well stream to a separator with no venting may eventually cease to successfully unload liquids due to changes in well conditions. The commenters add that the ostensible "design" method is therefore not an accurate predictor of whether unloading activities at a given well will or will not result in unloading during a given point in the well's life. The commenters conclude that framing the rule in terms of a well's "design" in this regard is not relevant and will only lead to confusion, and they recommend that EPA only require reporting of the events that result in venting from a given well, without labeling a well as "designed" to unload without venting.

Commenter (0831-AXPC) maintains that any extension of this requirement to existing sources would be inappropriate based on the clear focus of CAA 111(d)'s text, structure, and purpose on allowing states to consider the particular characteristics of a source over the course of its operations or remaining life. The commenter notes, however, that even solely in terms of the Administrator's new-source authority, a standard would not be "adequately demonstrated" and/or "achievable" if it did not account for the manner in which sources actually operate in the course of production.

Additionally, the commenter (0831-AXPC) claims that the use of wells' designed unloading methods and whether the methods are designed to vent or not, as the basis for determining an affected facility would create significant ambiguity, and recommends, overall, that the EPA should propose (in the supplemental proposal) a standard that requires reporting of unloading events that actually result in venting—not one, as in the November 2021 Proposal, that bases applicability around a source's and/or its unloading events' "design." The commenter recalls, under the Option 2, an affected facility would be defined as every well that undergoes liquids unloading using a method that is not designed to eliminate venting (*i.e.*, that results in emissions to the atmosphere).

Response I-12-8: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and (3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS OOOOb. See discussion in

sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, as well as EPA's request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations.<sup>8,9</sup> See Section 6.4.1 (Applicability) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the proposed definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and what constitutes a modification for liquids unloading operations.

In response to the commenter that maintains that any extension of this requirement to existing sources would be inappropriate based on the clear focus of CAA 111(d)'s text, structure, and purpose on allowing states to consider the particular characteristics of a source over the course of its operations or remaining life. BMPs to minimize or eliminate methane emissions are both "adequately demonstrated" and "achievable". See section XIII.C.3 of the final rule preamble for a discussion on state plans submitted in accordance with emission guidelines that include provisions for remaining useful life and other factors (RULOF). State plans submitted in accordance with these EG that include provisions for RULOF must comply with the subpart Ba general RULOF provisions in 40 CFR 60.24a. For informational purposes, the EPA has summarized the RULOF provisions that have been finalized in the subpart Ba rulemaking, which is separate and distinct from this action in section XIII.C.3 of the final rule preamble.

## **12.2 Proposed BSER**

### ***12.2.1 Proposed Well Liquids Unloading Requirements***

Comment: Commenter (0444-Damascus Citizens for Sustainability (DCS)) supports EPA's November 2021 Proposal to limit emissions by reducing emissions from maintenance activities, like liquids unloading. Similarly, commenter (0789-Pennsylvania Department of Environmental Protection (PDEP)) asks that EPA consider regulating natural gas emissions from well liquids unloading operations.

Response I-12-9: Commenters are supportive of requirements to limit/regulate emissions from well liquids unloading operations. Please see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements.

Comment: Commenter (1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*) asserts that it is unreasonable for EPA to regulate well liquids unloading operations as a modification under NSPS OOOOb. The commenter states that it is unaware of any existing technology that would enable them to control emissions associated with the different methods of liquids unloading, all of which, the commenter reports only occur intermittently for short periods of time. The commenter asserts that the proposed requirements incorrectly assume that technology

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<sup>8</sup> 87 FR 74781-74782.

<sup>9</sup> 87 FR 74781-74782.

exists that would allow for any emissions generated during such events to be controlled. According to the commenter, section 111 of the CAA prohibits the Agency from imposing new emission control requirements when there is no control technology available.

Commenter (1341-PGCC *et al.*) notes that although EPA's November 2021 Proposal suggests that "well liquids unloading" events in which emissions are "eliminated" may not be covered under proposed NSPS OOOOb, this potential exemption is of little value to the commenter's members (*i.e.*, conventional producers). The commenter writes that their members use tube swabbing, rabbits (plunger lifts), casing swabbing, and other methods as part of routine maintenance, including liquids unloading, on their wells, and contends that these events are very different from the "intermittent, high-emitting" events that EPA wants to regulate.

Response I-12-10: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to EPA's proposed standard of performance: perform well liquids unloading with zero methane or VOC emissions. The BSER proposed was to employ techniques or technologies that eliminate methane and VOC emissions. Where it was technically infeasible or not safe to meet the zero emissions standard, the proposal required that owners and operators employ BMPs to minimize methane and VOC emissions during well liquids unloading operations to the maximum extent possible.<sup>10</sup> See section 6.4.2 (Proposed BSER) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the proposed zero emission standard for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities.

With regards to the commenter that notes that they are unaware of any existing technology that would allow them to control emissions associated with the different methods of liquids unloading, the EPA assumes that the commenter is referring to add-on control technologies. While there are some owners and operators that report that they route emissions from liquids unloading events that vent emissions to an enclosed combustor or flare, the EPA recognizes that this is not a common practice. However, there are some gas well liquids unloading techniques that are currently employed that vent minimally or eliminate venting to the atmosphere.<sup>11</sup>

In response to commenter that indicated that their members use liquids unloading techniques as part of routine maintenance that are very different from the "intermittent, high-emitting" events that EPA wants to regulate, the final rule requires that owners or operators minimize or eliminate emissions of methane and VOC emissions to the atmosphere from all liquids unloading events. If liquids unloading technologies/techniques, where employed, vent emissions to the atmosphere, the EPA wants to ensure that BMPs are followed to minimize or eliminate emissions to the maximum extent possible.

Comment: Commenter (1341-PGCC *et al.*) expresses frustration that EPA ignored or failed to address several key recommendations offered by small entity representatives, including the recommendation to *not* propose liquids unloading requirements. The commenter maintains that a best management practice written into a regulation, particularly one that is very "site-specific,"

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<sup>10</sup> 87 FR 74781-74782.

<sup>11</sup> See discussion in section XII.D.e of November 2021 Proposal preamble. 86 FR 63211.

will not provide small entities clear instructions and [will] lead to confusion and significant risk of unwarranted enforcement actions. The commenter references the “Panel Report”.<sup>12</sup>

Response I-12-11: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>13</sup> The BSER proposed was to employ techniques or technologies that eliminate methane and VOC emissions. Where it was technically infeasible or not safe to meet the zero emissions standard, the proposal required that owners and operators employ BMPs to minimize methane and VOC emissions during well liquids unloading operations to the maximum extent possible.<sup>14</sup>

Based on the December 2022 Supplemental Proposal, BMP plans, meeting minimum criteria, were required to be developed by owners and operators. For unloading operations that use technologies or techniques that are not zero-emitting, an owner or operator was p develop, maintain, and follow a BMP plan to minimize venting of methane and VOC emissions to the maximum extent possible from each gas well liquids unloading operation. This BMP must meet the following minimum criteria:

(1) Include steps that create a differential pressure to minimize the need to vent a well to unload liquids,

(2) Include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,

(3) Unload liquids through the separator where feasible, and

(4) Close all wellhead vents to the atmosphere and return the well to production as soon as practicable.

While the December 2022 supplemental proposal included BMP minimum criteria, the proposed standards and presumptive standards did not specify rigid requirements for an owner or operator to follow and small entities would have flexibility on the specific elements and steps included in their BMPs based on their operations and technologies and techniques employed. The BMP plan minimum criteria proposed in the December 2022 Supplemental Proposal have been maintained in the final rule.

See section 6.4.2 (Proposed BSER) of Volume II of this RTC for comments and responses on the December 2022 Supplemental Proposal on the proposed zero emission standard for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which

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<sup>12</sup> Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector, Document ID No. EPA-HQ-OAR-2021- 0317-0074 (Sept. 2021) (Panel Report).

<sup>13</sup> 87 FR 74781-74782.

<sup>14</sup> 87 FR 74781-74782.

details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements.

Comment: Commenter (1341-PGCC *et al.*) maintains that the November 2021 proposed requirements to regulate liquids unloading operations are, at large, unnecessary due to infrequency and low-emitting nature of these events of well liquids unloading events, particularly at the wells of the commenter's members and would cause more environmental harm than benefit. According to the commenter, any requirement to control emissions during these infrequent events would be cost-prohibitive. The commenter underscores the point that recovery units would require electricity, which, the commenter writes, is unavailable at tens of thousands of conventional well sites in Pennsylvania and New York. The commenter continues to note that the cost of delivering electricity to these remote conventional well sites would be exorbitant and excessive. Consequently, vapor recovery using a generator for power would likely result in a net increase in emissions at the well sites of the Conventional Groups' commenter's members.

In a similar remark, commenter (1341-PGCC *et al.*) urges EPA to withdraw all aspects of the November 2021 Proposal purporting to regulate "well liquids unloading" at conventional oil and gas well sites in Pennsylvania and New York; arguing that the commenter's members should be allowed to continue to perform necessary maintenance and use stimulation techniques without the prospect of installing currently unavailable emissions controls. The commenter contends that forcing their members to pay for customized control systems and operate such systems during routine maintenance and stimulation on a well would be economically devastating and likely would lead to premature well shut ins.

Response I-12-12: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>15</sup>

For commenters that state that liquids unloading should not be regulated due to the cost of delivering electricity or the use of a generator and that the application of the proposed standards would result in premature shut-ins for conventional groups, the EPA has not finalized its December 2022 Supplemental Proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard.

See Chapter 6, section 6.4.2 (Proposed BSER) of Volume II of this RTC (RTC) Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) acknowledge that the routing of emissions back to a sales line is possible but not always practical and creates secondary emissions. The commenters note that one operator uses mobile gas lift compressors

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<sup>15</sup> 87 FR 74781-74782.

(MGLC) to unload wells to minimize venting emissions. According to the commenters, the estimated cost for routing unloading emissions to the sales line using mobile gas lift wellsite compressors for one operator is \$280K/year. The commenters note that the equipment size, layout, spacing requirements (Fire Class/Divisions), and cost would make it difficult to justify for use on marginal or remote wells; adding that the secondary emissions from the model 3406 gas powered compressor are approximately 4 tons/event carbon dioxide equivalent (CO<sub>2</sub>e).

Response I-12-13: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>16</sup> The EPA has not finalized its December 2022 Supplemental Proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) believe that venting should be permitted and that BMPs should be followed to minimize any associated emissions. The commenters note that nearly all non-venting liquids unloading events are done against a surface back pressure that is greater than atmospheric pressure. The commenters add that even small amounts of back pressure, such as unit increases in psi, could dispositively determine whether an unloading attempt is successful or not. The commenters explain that many wells will not unload against surface back pressure and therefore require venting to the atmosphere. The commenters caution that due to the variable nature of liquids unloading operations, attempts to contain the surging fluids and gases becomes a very difficult design problem. Specifically, the commenters note that engineering equations are not available to accurately estimate the pressure affects as the fluid stream reaches the surface equipment, and therefore, having a totally closed system without the ability to vent to the atmosphere, in many cases creates a safety concern – *i.e.*, potential bursting of tanks. To prevent this or similar events, the commenters maintain that surface equipment would need to be designed with safety factors that would result in significantly overrated and oversized equipment with the associated excessive cost – a solution which the commenters deem impractical, particularly for low producing wells.

The commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) add that much of the surface equipment needed for the separation of gas from liquids requires a threshold operating pressure and a flow regime that is not significantly sporadic. To be able to measure and control unloading emissions, the commenters contend that this separation – which is often not practical unless tanks that can vent to accumulate the sporadic flow stream are used which allow for liquid/gas gravity separation over time – would need to be completed. According to the commenters, the use of compressed nitrogen to unload wells is common practice, especially when a well does not have the ability to use produced gas – *e.g.*, a single well on a location, an exploration type well

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<sup>16</sup> 87 FR 74781-74782.

without any gathering infrastructure. The commenter explains that since the unloading gas stream will be a mixture of the injected nitrogen and formation gas the gas will have too high a nitrogen content to put in a sales line or to burn efficiently via a flare. Until the mixture can go to beneficial use, the commenters note that some venting may be necessary. The commenters emphasize that these operations make all attempts to minimize this venting, typically with a recirculation system.

Moreover, the commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) note that in certain basins/formations, a temporary shut-in to build pressure does not build enough delta between bottomhole pressure and surface pressure to overcome the production impediment caused by liquid holdup; therefore, unloading to a low-pressure system is required.

According to the commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC), even in circumstances where a non-venting solution may be possible, the amount of equipment, additional artificial lift engines, and associated secondary emissions, often makes it an obviously poor choice. The commenters also note that location size can also prevent the installation of any such equipment, particularly when there is not adequate and prudent spacing between wellheads and other potential ignition sources and fired equipment such as compressor exhaust and flares. The commenters agree that production engineers are professional problem solvers, and they should be empowered to come up with the best solutions, as discussed in the preceding comments.

Furthermore, the commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) recommend that production engineers attempt to capture methane emissions and put them into the sales line when practical. The commenters state that during plunger lift, gas lift assist, soap assist, venturi system lift, swabbing, and many other forms of liquids unloading, gas is often captured and routed to sales or to a control device (*e.g.*, flare, compression input, heaters, generators). The commenters maintain that this is in line with EPA's observation that "[s]electing a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production." [86 FR 63,211] While the commenters recognize that in many cases there are ways to achieve this with going to sales or a control device, they also acknowledge that when an operator can no longer do so, they still need to be able to vent. The commenters write, there are many Gas STAR partner reported opportunities (PROs) that address the cost side of these solutions that are highly variable.

Response I-12-14: The EPA appreciates the feedback and information provided by commenters. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>17</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the

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<sup>17</sup> 87 FR 74781-74782.



final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (0808-API) argues that non-emitting control measures under the November 2021 Proposal are work practices and EPA should correct its terminology in the Final Rule. The commenter writes that as a practical matter, the term “zero-emissions” is apt because the object of proposed standards, including liquid unloading standards that require owners or operators to perform liquids unloading with zero methane or volatile organic compound (VOC) emissions, is to eliminate methane and VOC emissions from the affected facility. But as a legal matter, the commenter claims that the term “zero-emissions” is imprecise and in error because proposed standards (for liquid unloading and pneumatic controllers) impose equipment or work practice obligations and do not impose a numeric emissions limitation of zero.

According to the commenter, the legal distinction is important because a fully compliant pneumatic controller or liquids unloading event may still have incidental VOC and methane emissions. The commenter acknowledges that no piece of equipment or work practice is perfect – even if implemented according to best practices. With that understanding, the commenter writes, the term “zero-emissions” expresses an idealized outcome that is belied by reality. The commenter continues, a zero-emissions numeric standard would unreasonably cause incidental emissions to be a violation of the standard. EPA should correct its terminology in the Final Rule by stating that non-emitting control measures under this rule are work practices.

Response I-12-15: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>18</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for EPA’s responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA’s final standards and presumptive standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

### ***12.2.2 Liquids Unloading BSER Analysis***

Comment: Commenter (1341-PGCC *et al.*) claims that EPA’s assumed emissions from “well liquids unloading” events does not include the relatively unique operations at the wells operated by the commenter’s conventional members – the study that is the sole basis for EPA’s estimates evaluated 107 wells, with 11 wells in the Appalachian region, none of which are configured like the wells owned and operated by the commenter’s members – and therefore, the commenter states that the EPA cannot regulate well liquids unloading events at the wells of the commenter’s members.

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<sup>18</sup> 87 FR 74781-74782.

Response I-12-16: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>19</sup> While the December 2022 supplemental proposal included BMP minimum criteria, the proposed standards and presumptive standards did not specify rigid requirements for an owner or operator to follow and small entities would have flexibility on the specific elements and steps included in their BMPs based on their operations and technologies and techniques employed. The BMP plan minimum criteria proposed in the December 2022 Supplemental Proposal have been maintained in the final rule.

Implementing the BMPs proposed in the December 2022 Supplemental Proposal and maintained in the final rule to minimize or eliminate VOC and methane emissions from gas well liquids unloading events constitutes requirements that every well affected/designated facility can implement.

Comment: Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) contend that the BSER analysis for velocity strings was incomplete and generally not applicable to a wide variety of unloading challenges – *e.g.*, fields where the potential for frac hits exists during normal prudent field development. In these cases, the commenters note that a significant amount of water will result in legacy offset wells and velocity strings will make the recovery and de-liquification of these wells extremely difficult or impossible as the tubing conduit, with reduced diameter, would create significant friction and back pressure. The commenters add that velocity strings also are very difficult to unload and swabbing, and plunger options are either reduced or eliminated due to the small diameter. Furthermore, the commenters note that velocity string sizing requirements change with time requiring replacement and they are therefore not considered permanent solutions for liquid unloading. The commenters state that the increased emissions and costs were not considered in the BSER analysis.

Response I-12-17: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>20</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for comments and EPA’s responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA’s final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Zero-emitting technologies and techniques are encouraged but are not required under the final rule. Nonetheless, the EPA acknowledges the commenter’s position regarding the analysis provided for velocity strings in the November 2021 proposal did not BSER analysis and that

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<sup>19</sup> 87 FR 74781-74782.

<sup>20</sup> 87 FR 74781-74782.

velocity strings generally not applicable to a wide variety of unloading challenges. Nonetheless, the EPA acknowledged in the November 2021 proposal BSER analysis that there are several techniques owners and operators can choose from to unload liquids, including manual unloading, velocity tubing or velocity strings, beam or rod pumps, electric submergence pumps, intermittent unloading, gas lift (e.g., use of a plunger lift), foam agents, wellhead compression, and routing the gas to a sales line or back to a process.

Comment: Commenters (0599-MSD, 0814-IPAA *et al.*, 0831-AXPC) question the methodology that was employed by EPA to establish cost reasonableness. Specifically, the commenters note that EPA's analysis, when establishing \$/tons of emission reduction in establishing reasonableness, does not include data on emission reductions. The Agency acknowledged that establishing an emission reduction that would be achievable by event is difficult as baseline level of management practices and emissions varies significantly. The commenters state that the \$/ton reduction is then calculated from the baseline level based on hypothetical emission reduction values of 10 percent, 25 percent, and 50 percent. The commenters emphasize that these are hypothetical values and therefore, questionable as representing reduction per event. Additionally, the commenters note that baseline emissions are a crucial factor in calculating the tonnage of reduction; yet EPA lacks transparency in providing justification for the baseline emissions applied in the calculation of cost effectiveness. As such, the commenters question EPA's cost-effectiveness of the "Non-Emitting Evaluation" option. To establish the cost-effectiveness for existing sources (*i.e.*, wells already equipped with "non-venting" technology such as plunger lift), the commenters note that EPA's BSER analysis is based on 2015 -2019 liquid unloading data from Subpart W, and the data shows 98 percent of "with plunger" wells are those equipped with automated plunger, for which, EPA cannot establish an emission reduction baseline; hence, the analysis is based on the remaining 2 percent of the well population representing manual liquid unloading operations. The commenters question the representation of this analysis since 98 percent of actual wells are equipped with automated plunger system from which EPA cannot establish actual reduction.

Response I-12-18: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>21</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

In response to commenters that express that the BMP analyses based on hypothetical emission reduction per event values of 10 percent, 25 percent, and 50 percent is questionable. As the commenter noted, the Agency acknowledged that establishing an emission reduction that would be achievable by event is difficult as baseline level of management practices and emissions varies significantly. No one, however, disputes that BMPs, when implemented, during gas well

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<sup>21</sup> 87 FR 74781-74782.

liquids unloading events that vent, would reduce vented emissions as a result of an owner or operator being required to follow a BMP plan to minimize or eliminate emissions to the maximum extent possible.

Comment: Commenter (0808-API) is concerned that EPA has not asserted an adequate legal basis for the November 2021 proposed emissions standards that allow for “technical feasibility” exceptions. The commenter proclaims that the fact that EPA needed to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under section 111 of the CAA. According to the commenter, a “standard of performance” must reflect the degree of emissions limitation “achievable” through application of the best system of emissions reduction that EPA finds to be “adequately demonstrated.” CAA section 111(a)(1). The November 2021 proposed non-emitting standards do not meet this requirement for two reasons: First, EPA has not demonstrated that techniques that eliminate emissions from liquids unloading events are “demonstrated in practice” for purposes of designating such techniques as BSER, and second, the proposed non-emitting standards of performance are legally questionable because they are not “achievable,” as demonstrated by the need to establish exceptions to make the standard sufficiently practicable. Foremost, the commenter acknowledges that that non-emitting liquids unloading techniques can be used in some circumstances and that associated gas can be routed to a sales line in some situations, but the need to create exceptions under both standards shows that non-emitting techniques are not demonstrated in practice for the full range of regulated activities and circumstances. The commenter argues that EPA needs to seek to avoid the obligation to show that non-emitting techniques are demonstrated in practice by creating exceptions for situations where non-emitting techniques are not demonstrated in practice. According to the commenter, this incorrectly relieves EPA of the burden of promulgating achievable standards in the first instance and improperly defers infeasibility determinations to the time when the rule is implemented and enforced rather than when the rule is promulgated – *i.e.*, puts the burden on affected facilities to prove to EPA that they qualify for the exceptions. An approach ultimately not supported by the commenter. The commenter provides that the court (*i.e.*, *Essex Chemical Corp. v. Ruckelshaus*) confirmed that, given adequate justification, EPA may set technology-forcing standards of performance under CAA section 111. However, the commenter stresses that this does not support EPA’s November 2021 Proposal to determine that non-emitting techniques are “adequately demonstrated” as it is clear that there are a significant number of potentially affected facilities will not be able to meet the non-emitting standards. The commenter urges EPA in the upcoming supplemental proposal to provide a better explanation of how setting presumptively applicable non-emitting standards with a case-by-case “off ramp” satisfies these statutory requirements – BSER to be “adequately demonstrated” and standards of performance to be “achievable.”

Response I-12-19: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>22</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See also

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<sup>22</sup> 87 FR 74781-74782.

sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (0831-AXPC, 0599-MSC, 0814-IPAA *et al.*) believe that enclosed combustion devices and thermal oxidizers should be considered as control options.

Commenters (0599-MSC, 0831-AXPC, 0814-IPAA *et al.*) claim that EPA reports and peer reviews on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events, indicate that a flare cannot be used in all situations. As an example, the commenters reference a peer review<sup>23</sup> which states, "[t]he flowing characteristics during venting operations inhibit the design of flare equipment." During the unloading operation, initial gas flow rate and pressure are high and decline rapidly over a short period of time. Flare design (tip diameter) is based on flow rate and design criteria can be found in Radian Corporation/EPA 1995 Report – Chapter 7 on Flares<sup>24</sup>. In addition, the commenters note that the sporadic nature of liquid unloading venting operations would require either a continuous pilot or electronic igniter, and the design cost associated with the requirements needed for this type of flow would be cost prohibitive. Additional information for flare applicability in this context is available in EPA Gas Star PRO Fact Sheets No. 904 "Install Flares" and No. 903 "Install Electronic Flare Ignition Devices".

While the commenters (0599-MSC, 0831-AXPC, 0814-IPAA *et al.*) recognize that EPA's decision to not to consider a flare as a control option for unloading events could be justified with respect to some operational scenarios, the commenters maintain that there are opportunities to use flares in many cases, and these cases are likely the ones that offer the biggest opportunity for methane emission reductions. To illustrate, the commenters write, consider the methods of liquids unloading that use an artificial lift engine, *e.g.*, gas lifting the fluids with compressed gas. In this example, the commenters note that the well still may require a very low surface pressure to effectively remove the liquids and the quantity of produced gas could be significant before it can be directed to sales or recirculated into a gas compressor intake; concluding that a flare as a control device in this situation would be technically feasible and likely result in a safer operation. The commenters suggest that flares should be considered as a control option in this rulemaking, and an unloading event controlled with a flare should be considered as non-venting liquids unloading.

Response I-12-20: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>25</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions,

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<sup>23</sup> Jim Bolander, P.E., Senior Vice President, Southwestern Energy (SWN). Review Submitted: April 2014. Pg. 8

<sup>24</sup> Chapter 7 FLARES: Diana K. Stone, Susan K. Lynch, Richard F. Pandullo, Radian Corporation Research Triangle Park, NC 27709, Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, December 1995.

<sup>25</sup> 87 FR 74781-74782.

unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments. Under the final rule/presumptive standards, owners or operators are also allowed the option to comply with the GHG and VOC standards by reducing methane and VOC emissions from each gas well liquids unloading event by 95 percent by routing emissions to a control device via a closed vent system (CVS). The emissions reduction that would be achieved by this option could be greater than or equal to what could be achieved through the implementation of BMPs.

Comment: Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) offer several examples that would not allow liquids unloading to be performed without venting. Foremost the commenters write that production engineers should be empowered to make the best production decision, and when they decide venting is required, it should be considered technically necessary. According to the commenters, many wells need to unload to an atmospheric tank for unloading to be successful; sporadic unloading is difficult to model and the selection of surface equipment that does not vent creates safety concerns; separation equipment requires threshold operating pressures and perform poorly under sporadic flow; the use of compressed nitrogen to unload wells often requires some venting; high surface producing pressures can result from gathering and compressor system maintenance or unplanned upsets. The commenters explain that wells often cannot unload against these higher surface pressures; and locations are often too small to accommodate the significant amount of equipment which would be necessary for non-venting liquids unloading.

Response I-12-21: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>26</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

### ***12.2.3 Zero Emissions Standard***

Comment: Commenter (0777-Ascent) argues that EPA should replace the infeasible "zero emissions" standard with a requirement that affected well liquids unloading operations minimize emissions through BMPs. The commenter states that they have significant experience using a

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<sup>26</sup> 87 FR 74781-74782.

variety of practices to safely and effectively minimize the emissions associated with gas well liquids unloading but worry that those practices would not satisfy EPA's contemplated "zero emissions" requirement. According to the commenter, there are many reasons why liquids may accumulate in a wellbore and require liquid unloading, some of which are due to external factors not in the control of the well operator. The commenter states that the November 2021 proposed standard would necessitate a detailed review and discussion of infeasibility for each event with no benefit to emissions.

The commenter (0777-Ascent) recommends that, rather than establish a "zero emissions" standard with an exception for unloading with minimized emissions when zero-emissions unloading is technically infeasible, EPA propose the use of BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible as the standard itself. The commenter warns that the program contemplated by EPA sets an impossible compliance bar, and further reiterates that a proposed standard to develop and use BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible will achieve the same emissions reductions while eliminating the unnecessary burdens associated with demonstrating that zero-emissions unloading is infeasible.

Moreover, the commenter (0777-Ascent) suggests that EPA use the API Environmental Partnership Program materials<sup>27</sup> to help define a program for what qualifies as BMPs for minimizing the VOC and methane emissions associated with well liquids unloading.

Response I-12-22: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>28</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (0808-API) suggests that the November 2021 proposed BSER may not consider/include exceptions that are deemed or determined to be technically infeasible, because BSER must be technically feasible for the source category. The commenter provides a brief overview of the proposed standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions." [86 Fed. Reg. at 63179] The commenter mentions that the proposed standard is based on a determination that non-emitting techniques constitute BSER for these sources. At the same time, the commenter points out that

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<sup>27</sup> <https://apitep02.wpengine.com/what-were-doing/manual-liquids-removal/>.

<sup>28</sup> 87 FR 74781-74782.

EPA acknowledges that non-emitting techniques are not always feasible or safe and provide alternative standards to cover those situations.

In general, the commenter (0808-API) supports this approach as a practical matter and agrees that non-emitting measures and methods should be used where they are technically feasible and cost effective. The commenter highlights that the EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. With that in mind, the commenter believes that the proposed alternative measures are a common-sense solution.

Response I-12-23: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>29</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (0844-EDF *et al.*) supports EPA finalizing a standard of zero emissions for liquids unloading events and should consider affected facilities any site that undergoes liquids unloading. The commenter suggests EPA require rigorous documentation of all liquids unloading events and clear best practices that must be followed in limited situations in which liquids unloading cannot be conducted with zero emissions.

Specifically, the commenter (0844-EDF *et al.*) writes that EPA should limit permissible circumstances when liquids unloading can be conducted without zero emissions and require rigorous documentation of why venting had to occur. The commenter notes that EPA has proposed to allow venting if "it is technically infeasible or not safe to perform liquids unloading with zero emissions," in which case EPA proposes "to require that an owner or operator establish and follow [BMPs] to minimize methane and VOC emissions during liquids unloading events to the extent possible."<sup>30</sup> According to the commenter, EPA does not intend to "dictate all of the specific practices that must be included," but rather "would specify minimum acceptance criteria required for the types and nature of the practices."<sup>31</sup> The commenter maintains that this is too nebulous and is likely to result in regular venting, followed by operators checking off a handful of best practices. The commenter recommends that EPA clearly define best practices, list them in

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<sup>29</sup> 87 FR 74781-74782.

<sup>30</sup> 86 FR 63,179.

<sup>31</sup> *Id.*



hierarchical order, and require operators to follow the practices or otherwise provide rigorous documentation as to why they could not do so.

Response I-12-24: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.

<sup>32</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for comments and EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

See section XI.F.3.b of the final rule preamble discusses the final rule recordkeeping and reporting requirements that apply to gas well liquids unloading events that vent to the atmosphere.

#### ***12.2.4 Best Management Practices***

Comment: Commenter (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) states that there are a variety of liquids unloading processes (*e.g.*, blowing a gas well down to a tank, swabbing a cased hole, and artificial lift), which are often tailored to the best production methods for the well. The commenter contends that EPA should not dictate production methods to producers. The commenter adds that many of their members participate in The Environmental Partnership whereby participants commit to monitor the manual unloading process onsite or in close proximity and close all wellhead vents to the atmosphere as soon as practicable. Overall, the commenter supports and encourages EPA to allow the use of these best management practices for this operation.

Commenters (0599-MS, 0831-AXPC) agree with EPA's observation, at 86 Fed. Reg. 63,180, "that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible for such cases."

Similarly, commenter (0599-MS) supports the use of BMPs when venting is required for liquid unloading activities – as proposed for unloading technologies or techniques that result in venting to the atmosphere – *i.e.*, implement BMPs to ensure that venting is minimized and maintain BMPs as records, and record instances when they were not followed. Additionally, the commenter supports liquid unloading BMPs that empower production engineers to direct

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<sup>32</sup> 87 FR 74781-74782.

unloading activities without technical justification and that are aimed at daily operational venting minimization.

Commenter (0831-AXPC) believes that it is crucial to allow flexibility for liquids unloading operations and appreciates that EPA acknowledges this.

Commenter (0743-WEA) is supportive, in general, of developing BMPs to be applied to liquids unloading; however, the commenter stresses doing so in such a way that avoids duplication of reporting efforts and unnecessary requirements.

Commenter (0808-API) generally supports a work practice standard built around the BMP approach described by EPA in the November 2021 Proposal. More specifically, the commenter supports EPA in allowing flexibility for operators to manage and operate their wells based on the engineering needs of the well. As a point of clarification, the commenter notes that the November 2021 Proposal characterizes several techniques as non-venting techniques. According to the commenter, some of the solutions discussed may minimize emissions from unloading, but not fully eliminate them.

Response I-12-25: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii, and IV.F.3.b of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>33</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (0599-MS, 0831-AXPC, 0814-IPAA *et al.*) emphasize that automation reduces the safety risk of exposing personnel to hazardous atmospheres. The commenters agree with EPA's observation, at 86 Fed. Reg. 63,213, that "there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids." In addition, the commenters also agree that "it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions."

Specifically, commenters (0599-MS, 0814-IPAA *et al.*) object to BMPs that include a requirement for the direct measurement of vented emissions and/or an operator to be in close proximity to the unloading activities when the use of automation equipment, remote sensors, and other surveillance technologies are used, as they would be a safety concern. The commenters state that an emission quantification hierarchy of direct measurement, engineering equations,

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<sup>33</sup> 87 FR 74781-74782.

and emission factors will for almost all sources result in the most accurate emission values; however, engineering challenges, economic criteria, and safety considerations will result in the optimal selection on a case-by-case basis. The commenters underscore the point that there are safety concerns regarding direct measurement of venting emissions; adding that National Institute for Occupational Safety and Health- Occupational Safety and Health Administration (NIOSH-OSHA) have issued a Hazard Alert<sup>34</sup> – a supplement to the OSHA Alliance Tank Hazard Alert released in 2015 [National Service, Transmission, Exploration & Production Safety (STEPS) Network 2015], which describes the safety and health hazards when workers manually gauge or sample fluids from production, flowback, or other tanks. The commenters add that this alert also describes ways to protect workers by eliminating or reducing exposures to hazardous atmospheres, and actions employers should take to ensure that workers are properly aware of the hazards and protected from exposure to hydrocarbon gases and vapors. According to the commenters, although there are many cases of direct measurement being performed on methane emissions many of them are done in a controlled experimental environment. The commenters note that, in reality, workers need to use extreme caution whenever working around hydrocarbon emissions and many of the direct measurement techniques used and suggested (see 3CCAC Appendix A: Conducting Emission Surveys, Including Emission Detection, and quantification equipment, which include turbine meters, vane anemometers, hotwire anemometers) actually expose workers to these emissions and therefore should be avoided.

Response I-12-26: The final rule does not require direct measurement of vented emissions from liquids unloading events, however, implementing BMPs to minimize or eliminate emissions does require owners or operators ensure that steps outlined in their BMP are properly implemented to minimize venting to the maximum extent possible, which can be by automated or manual means.

See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, IV.F.3.a.iii, and IV.F.3.b of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.

<sup>35</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for EPA’s responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA’s final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (0777-Ascent) argues that EPA should not use NSPS OOOOb and EG OOOOc to establish a prescribed set of practices or steps that limit an owner or operator’s flexibility in designing and implementing BMPs to minimize emissions from well liquids unloading. The commenter insists that operators should have flexibility to design their BMPs in a

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<sup>34</sup> Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. <https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf>.

<sup>35</sup> 87 FR 74781-74782.

way that best fits their operations while maintaining the goal of minimizing emissions during the unloading event.

Commenters (0743-WEA, 0808-API) affirm EPA's decision to allow flexibility for liquids unloading operations – a complex topic that has historically been difficult to address from a regulatory perspective (as noted by commenter 0808-API) and support EPA in providing criteria for consideration for inclusion in an operator's BMP. According to the commenters, techniques used for liquids unloading are certainly not a one-size-fits-all application. The commenters add that techniques used for liquids unloading are certainly not a one-size-fits-all application. According to the commenter, while certain technique(s) may reduce emissions from one well source, those same techniques, if used on a well with differing characteristics, may result in an increase in emissions. Consequently, the commenter (0743-WEA) asks that EPA work with industry to select already developed BMPs to apply to liquids unloading operations.

Commenters (0599-MSD, 0814-IPAA *et al.*, 0831-AXPC) agree with EPA's observation that "[s]electing a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production" [86 FR 217, 63211]. The commenters maintain that describing clearly where a well stream is directed via a process flow diagram and explanation is not in most cases a trivial explanation. According to the commenters, many well sites, especially sites with multiple wells, have a complex surface piping system for equipping the site with the various liquid unloading activities that could result, (e.g., gas injection, recirculation of produced gas in wellsite compression, vapor recovery unit (VRU) control options, combustors, oxidizers, multiple use of separators and tanks often manifolded together, soap and chemical delivery systems).

The commenters (0599-MSD, 0814-IPAA *et al.*) note that many member companies employ the Best Practice Implementation Principle, as defined in the API's *The Environmental Partnership Program for Manual Liquids Unloading: Operators*. The commenters add that although companies are committed to monitoring the manual unloading process and close all wellhead vents to atmosphere, it is important to point out that the definition of Manual Liquids Unloading is "an operation undertaken by an operator to temporarily divert the flow from the well to an atmospheric vent without assistance of automated equipment", and the definition of Monitored: "operator on-site or in close proximity and able to close atmospheric vent as soon as practicable to minimize the gas vented to atmosphere." The commenters state that the use of automation is a very important point in this BMP formulation, and the use of remote sensors, mechanically activated devices, positive closure and seal indicators, camera technology, and associated surveillance and alarming can greatly enhance the effectiveness of optimal liquid unloading and in many cases is more effective than relying on personnel to be on site. Therefore, the commenters contend that BMPs should not require having a person onsite during the liquids unloading event to expeditiously end the venting when the liquids have been removed (as suggested), but rather BMPs should encourage the continued use and expansion of use of automation technologies that are scalable and economic.

Commenter (0831-AXPC) acknowledges that the process footprint during a liquids unloading event can change throughout the life of the well depending on well conditions. According to the commenter, describing clearly where a well stream is directed via a process flow diagram and

explanation is often a complex and burdensome task that would ultimately not yield value in this context. Moreover, the commenter reports that the direct measurement of vented emissions is not always possible and runs a serious risk of exposing personnel to hazardous atmospheres. The commenter reminds EPA that NIOSH-OSHA have issued a Hazard Alert associated with working around open top tanks,<sup>36</sup> and generally recommend protecting workers by eliminating or reducing exposures to hazardous atmospheres.

Commenter (0924-U.S. Small Business Administration (SBA)) suggests that when EPA drafts implementing rule text, that EPA include deference to the BMP developed for that operation reflecting production engineering decisions. The commenter further suggests that EPA provide enforcement assurance that following a written BMP is sufficient to comply with the NSPS, and that methane emissions from liquids unloading operations cannot be used in of itself to show a violation of the NSPS.

Commenters (0599-MS, 0814-IPAA *et al.*) object to BMPs with any prescriptive requirement for using any specific unloading technology – like the requirement to try a plunger lift, or attempt the use of an artificial lift engine, both of which, the commenters write, can be found in the New Mexico draft language, as they would be too prescriptive in nature and would potentially impact the production engineer’s best design decisions.

Commenters (0599-MS, 0831-AXPC, 0814-IPAA *et al.*) recommend that EPA consider common elements (found within New Mexico [NM], Pennsylvania [PA], and Colorado [CO] state approved BMPs), which are non-prescriptive and allow for operators to employ their expertise in the selection of appropriate liquids unloading practices, in determining the minimum BMP element requirements. According to the commenters the commonality or consistencies of these elements reflects recognized and common practices that are proven. One such common practice, identified by the commenters, is to require monitoring during a liquid unloading event via the presence of an operator on-site or in close proximity. According to the commenters the application of remote monitoring via sensor technology may also be employed as feasible.

Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) support BMPs that:

- Require an operator at the wellsite or in close proximity unless the use of automation equipment, remote sensors, and other surveillance technologies are used.
- Require the operator to report when the BMPs have not been followed.
- Allow for the use of flaring as a control option.
- Allow for routing emissions to a sales line or back to a process.

Commenters (0743-WEA, 0808-API) supports the language that EPA includes in the November 2021 proposal preamble:

...following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to

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<sup>36</sup> Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. <https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf>.

opening to atmosphere via storage tank, unloading through the separator where feasible, and requiring an operator to remain on-site throughout the unloading, and/or closure of all well head vents to the atmosphere and return of the well to production as soon as practicable.

Commenter (0743-WEA) maintains that this language, if applied as criteria for an operator's BMPs, would provide for emissions minimization across all types of liquids unloading events without prescribing certain technologies.

Response I-12-27: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, IV.F.3.a.iii, and IV.F.3.b<sup>37</sup> of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>38</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

With regards to comments that BMPs should not include a requirement for direct measurement of vented emissions, the final rule does not require direct measurement of vented emissions from liquids unloading events. See Response I-12-26 of this Chapter.

With regards to the commenter that requests that EPA allow the use of flaring as an emissions control option. Under the final standards under NSPS OOOOb and presumptive standards under EG OOOOc, based on these and other comments, owners or operators are allowed the option to comply with the GHG and VOC standards by reducing methane and VOC emissions from each gas well liquids unloading event by 95 percent by routing emissions to a control device via a CVS, which can include a flare.

Comment: Commenter (0756-Baker Hughes) believes that BMPs should include technologies that reduce the frequency of events as a means of reducing overall emissions; noting (along with commenter (0729-Energy Workforce & Technology Council (EWTC))) that there are significant opportunities to reduce emissions associated with liquids unloading despite the diversity of circumstances and technologies involved. According to the commenters, one means of facilitating reductions in methane emissions generated by liquids unloading is to deploy advanced methods that reduce the frequency of unloading events. To illustrate, the commenters mention technologies offered to improve production efficiency.

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<sup>37</sup> 87 FR 74781-74782.

<sup>38</sup> 87 FR 74781-74782.

Additionally, commenter (0729-EWTC) writes there are artificial lift solutions that use advanced analytics and “smart” edge technology to boost production and reduce associated methane emissions from oil and gas wells.

According to commenter (0756-Baker Hughes), Vine Energy recently signed a contract to deploy its artificial lift solution, Productionlink™ Edge, across 100 natural gas wells in Louisiana's Haynesville Shale.

Both commenters (0729-EWTC, 0756-Baker Hughes) acknowledge, this follows a three-month joint pilot project in Haynesville Shale using the artificial lift solution across 10 wells, during which Vine Energy's gas production increased by 5 percent and well unloading events decreased by 94 percent.<sup>39</sup>

Response I-12-28: The EPA appreciates the commenters' information on artificial lift/technology solutions to reduce venting of methane and VOC emissions from gas well liquids unloading events. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, IV.F.3.a.iii, and IV.F.3.b<sup>40</sup> of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>41</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (0599-MSA, 0814-IPAA *et al.*, 0831-AXPC, 0924-SBA) recommend that, for states where a BMP governing liquid unloading event is required under the states' regulations (*e.g.*, permit requirements), BMPs be deemed sufficient and satisfy the requirements of NSPS. Commenter (0831-AXPC) writes, that Congress designed NSR to be at least as stringent as the NSPS program, see CAA section 169(3) (defining Best Available Control Technology, the standard applicable under NSR, as an emissions limit that “[i]n no event” shall result in more emissions than those allowed under any applicable standard under 111). Therefore, the commenter recommends that a source's NSR-derived requirements for an activity be deemed to satisfy the requirements of the NSPS. According to the commenter, doing otherwise would contradict the statute and impose unnecessary duplicative regulations for no additional emissions benefit, and would be doubly inappropriate under the state-planning process under CAA 111(d), given the strong and explicit textual commitment to federalism and state flexibility in that subsection's text and structure. The commenter suggests that EPA allow states

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<sup>39</sup> <https://www.bakerhughes.com/company/news/vine-energy-deploys-baker-hughess-advanced-analytics-enhance-gas-production-and>

<sup>40</sup> 87 FR 74781-74782.

<sup>41</sup> 87 FR 74781-74782.

to incorporate into their state plans under new EG OOOOc their NSR provisions for sources' liquids unloading events. The commenter contends that, to do otherwise would violate the cooperative federalist design of not one but two portions of the statute: CAA 111(d) and the states' NSR programs as incorporated in their State Implementation Plans under CAA 110.

Response I-12-29: See section XIII.C.3 of the final rule preamble for a discussion on state plans submitted in accordance with EGs that include provisions for remaining useful life and other factors (RULOF). State plans submitted in accordance with these EG that include provisions for RULOF must comply with the subpart Ba general RULOF provisions in 40 CFR 60.24a. For informational purposes, the EPA has summarized the RULOF provisions that have been finalized in the subpart Ba rulemaking, which is separate and distinct from this action in section XIII.C.3 of the final rule preamble.

### ***12.2.5 Other Requirements – Legacy Wells***

Comment: Commenter (0585-KOGA) recommends that a threshold of four (4) liquid unloading events per year be permitted before a singular well becomes an affected facility. According to the commenter, the additional compliance requirements could be the difference in eliminating or maintaining a large group of existing gas wells; or reducing the remaining life of many wells. The commenter expresses concern that wells that would have otherwise been considered exempt because they vent only a small amount of methane during a “liquid unloading” event that may only occur once a year or once every five years would become affected facilities and have to comply with NSPS OOOOb requirements of fugitive emission surveys and records submission for EPA.

The commenter (0585-KOGA) reports that there are a large number of “legacy” gas wells in the Appalachian Basin, comprised of just a wellhead that EPA rightly is proposing to exempt from EG OOOOc requirements. The commenter states that, as EPA notes, a significant number of these legacy wells with low pressure and low flow develop fluid buildup issues. In order to keep producing gas the fluid needs to be removed from the wellbore. The commenter explains that the fluid removal typically needs to be completed as frequently as once or twice per year and as infrequently as once every few years. The commenter adds that during these “unloading” operations a portion of the volume of gas in the wellbore is vented along with any additional production. The commenter states that the volume of this vented gas from the shallow wells operating at pressures well under 100 psi is less than 25,000 Standard Cubic Feet. Therefore, the commenter contends that even if liquid unloading events occurred 4 times a year, the total volume vented would be well under the 3 tons per year threshold proposed by EPA for exemption, and the 4 tons per year threshold recommended by the commenter.

The commenter (0585-KOGA) provides the following example: A typical Kentucky gas well is 1,500 feet deep and constructed with 6.25-inch internal diameter casing. The well has a volume of 320 cubic feet (6.25-inch diameter = 0.26 feet radius, volume =  $\text{Pi} \times r^2 \times h$ , volume =  $\text{Pi} \times (0.26 \text{ ft})^2 \times 1,500 \text{ ft} = 320 \text{ ft}^3$ ). At 50 psi that gas volume is 1,134 cubic feet (at standard conditions). Assuming the composition is 80 percent methane, the commenter writes, the methane emissions from the well casing is 31.8 pounds per event. According to the commenter,



if the well has an open flow of 40,000 cubic feet per day, the production is 10,000 ft<sup>3</sup>/day during the 6 hours required to remove the accumulated liquids. Approximately 11,000 ft<sup>3</sup> of gas is vented (10,000 ft<sup>3</sup> + 1,134 ft<sup>3</sup>), of which, the commenter notes, 80 percent is methane or 8,900 cubic feet of methane. The density of methane is 0.035 pounds/ft<sup>3</sup>. 8,900 ft<sup>3</sup> x 0.035 pounds/ft<sup>3</sup> = 311 pounds of methane vented per unloading event. The commenter concludes that the proposed well could complete 19 unloading events during a year before exceeding EPA's 3 tons per year threshold – the emissions rate is primarily driven by the production rate of the well, not the physical size of the wellbore.

Response I-12-30: See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, IV.F.3.a.iii, and IV.F.3.b<sup>42</sup> of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>43</sup> The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See Chapter 6, section 6.4.2 (Proposed BSER, subsection 6.4.2.2 Zero Emission Standard and subsection 6.4.2.4 Best Management Practices (BMPs)) of Volume II of this RTC Document for EPA's responses to comments on the December 2022 Supplemental Proposal. See also sections X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and sections XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

## 12.3 Liquids Unloading Definition

Comment: Commenter (0808-API) recommends that EPA clearly define liquids unloading within NSPS OOOOb. The commenter explains that other well maintenance and workover activities may occur on a well, and these activities are distinctly different, require different equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. To address this clarification, the commenter offers the following definition for "Liquids Unloading":

*Liquids Unloading* means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production from natural gas wells. Routine well maintenance activities, including workovers, swabbing, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.

Response I-12-31: The EPA received a similar comment on the December 2022 Supplemental Proposal from this commenter. EPA's response to this commenter's proposed changes to the December 2022 Supplemental Proposal liquids unloading definition is provided at Volume II of this RTC, see section 6.4.3 of Chapter 6 (Response II-6-102). See final definition of "liquids unloading" at 40 CFR 60.5430b.

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<sup>42</sup> 87 FR 74781-74782.

<sup>43</sup> 87 FR 74781-74782.

## 12.4 Direct Measurements of Gas Volume

Comment: Commenter (0776-CDPHE) contends that EPA's estimation method in the Greenhouse Gas Reporting Program, Subpart W, 40 CFR Part 98 (GHGRP), does not reliably calculate the volume of gas emitted during a well liquids unloading or maintenance activity. Accordingly, the commenter reports that they would require operators to use more direct measurements of this volume in their calculations.

Response I-12-32: The final rule requirements do not require that owners or operators measure/calculate or report liquid unloading vented emissions as required under GHGRP 40 CFR Part 98 Subpart W (subpart W) using Equations W-7, W-8, or W-9 of 40 CFR 98.233(f). The EPA streamlined recordkeeping and reporting requirements in the final rule to include the minimum required records and reports to ensure compliance with the final standards/presumptive standards. These streamlined requirements exclude requiring owners and operators having to measure/calculate or report liquid unloading vented emissions which are being reported under subpart W. See sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements.

## 12.5 Recordkeeping and Reporting Requirements

Comment: Commenter (0599-MSD) requests that EPA not consider record keeping and reporting requirements for non-venting liquid unloading events, but instead, consider existing data as reported under Subpart W to account for liquid unloading events resulting in vented emissions. The commenter maintains that it is not warranted to maintain records for non-venting events, and the lack of a framework for what constitutes a non-venting event renders it impractical or not possible to qualify or quantify a non-venting event. To illustrate, the commenter provides that the period of time when a well equipped with a plunger system sends the well stream directly to a separator with no vented emissions would qualify as a non-venting period. The commenter states that it is unclear how liquid unloading events during this period would be quantified (*e.g.*, a count of plunger cycles that successfully lift liquids and unload).

Commenter (0749-PAW) notes that non-vented liquids unloading reporting requirements are not feasible due to the nature of those events and administratively burdensome with no net gain in emission reductions. The commenter adds that liquids unloading will inevitably happen to every well at some point in its lifetime. By considering a liquid unloading event a modification, the commenter maintains that all well site facilities would become affected, and this would lead to an administrative burden with reporting and leak detection and repair (LDAR) monitoring while not reducing emissions.

Response I-12-33: The EPA streamlined recordkeeping and reporting requirements in the December 2022 Supplemental Proposal and final rule to include the minimum required records and reports to ensure compliance with the proposed and final standards/presumptive standards.

See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected

facility/designated facility, and proposed liquids unloading operation requirements.<sup>44</sup> Please also see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements, including the final recordkeeping and reporting requirements.

Comment: Commenters (0599-MS, 0749-PAW, 0814-IPAA *et al.*, 0831-AXPC) note that, for reporting of liquid unloading events that result in vented emissions, EPA currently requires reporting of liquid unloading vented emissions under GHGRP 40 CFR Part 98 Subpart W (subpart W) using Equations W-7, W-8, or W-9 of §98.233(f). The commenters suggest that the current reporting methodology options are adequate and urge EPA to consider existing data reported under this Subpart W and not impart additional unnecessary reporting requirements. Commenter (0749-PAW) stresses that any additional reporting requirements would be duplicative and burdensome with no resulting emission reductions.

Commenter (0808-API) contends that the November 2021 Proposal Option 1, as written, would generate a significant amount of administrative burden by requiring operators to track all unloading events, including unloading events that are automated (on artificial lift or pump jacks), as well as those that do not vent any emissions to the atmosphere. The commenter notes that operators already report the number of liquids unloading events to EPA under the GHGRP. According to the commenter, several of the proposed reporting requirements/information – *e.g.*, the number of liquids unloading events in an annual report, are duplicative of other EPA reporting requirements.

Commenter (0831-AXPC) contends that the November 2021 Proposal Option 2 approach (which would apply to gas wells venting to the atmosphere) is consistent with EPA emission reporting requirements under the Greenhouse Gas Reporting Program at 40 CFR Part 98, where Calculation Methodology 1 states “. . . where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing . . .” The commenter recommends that EPA utilize the existing required reporting for liquids unloading under Subpart W, and that EPA not impose additional reporting requirements.<sup>45,46</sup> The commenter recommends protecting workers by eliminating or reducing exposures to hazardous atmospheres and believes that EPA's GHGRP is adequate for liquids unloading reporting and quantification.

Response I-12-34: The EPA streamlined recordkeeping and reporting requirements in the December 2022 Supplemental Proposal and final rule to include the minimum required records and reports to ensure compliance with the proposed and final standards/presumptive standards. The final rule recordkeeping and reporting requirements do not require that owners or operators measure/calculate or report liquid unloading vented emissions as required under GHGRP 40 CFR Part 98 Subpart W (subpart W) using Equations W-7, W-8, or W-9 of 40 CFR 98.233(f).

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<sup>44</sup> 87 FR 74781-74782.

<sup>45</sup> For reporting of liquids unloading events that result in vented emissions, the EPA currently requires reporting of liquids unloading vented emissions under GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f).

<sup>46</sup> Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. <https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf>.

See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>47</sup> Please also see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements, including the final recordkeeping and reporting requirements.

Comment: Commenters (0599-MS, 0814-IPAA *et al.*, 0831-AXPC) object to BMPs with any of the following requirements as they would be a record keeping and reporting burden with no direct emission reduction benefit:

- Technical justification for the unloading methodologies employed.
- Process flow explanation and or diagrams of unloading activities.
- Historical account of all activities associated with attempts to unload wells. (0599-MS, 0814-IPAA *et al.*)
- Direct measurement of vented emissions. (0831-AXPC)

Response I-12-35: While the final rules (*i.e.*, NSPS OOOOb and EG OOOOc) require that BMPs be implemented to minimize or eliminate methane and/or VOC for well affected/designated facilities that vent to the atmosphere, none of the requirements that commenters objected to were included in the final monitoring, recordkeeping and reporting requirements. The EPA streamlined recordkeeping and reporting requirements in the final rule to include the minimum required records and reports to ensure compliance with the final standards/presumptive standards.

See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>48</sup> Please also see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements, including the final recordkeeping and reporting requirements.

## 12.6 Other Comments

### 12.6.1 Maintenance Activities – Recordkeeping and Reporting Requirements

Comment: Commenter (0727-OSEE/ODEQ) expresses concern about maintenance activities that require a well be opened for servicing. 86 Fed. Reg. 63119. Specifically, the commenter asks, “[i]f a well is opened for servicing, would those interventions be subject to reporting and/or recordkeeping? If so, what requirements would be applicable?”

Response I-12-36: The commenter did not provide sufficient context regarding “servicing” for the EPA to respond to. However, the EPA acknowledges that there may be a need for

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<sup>47</sup> 87 FR 74781-74782.

<sup>48</sup> 87 FR 74781-74782.

applicability rule clarity and considered these and other comments requesting clarifications when developing the December 2022 Supplemental Proposal regulatory text. If servicing the well is because an owner or operator is unloading liquid and the well is a well affected facility/designated facility, that activity would be subject to requirements under NSPS OOOOb and EG OOOOc. Minimal recordkeeping and reporting requirements apply when liquids unloading technologies and techniques employed do not result in venting to the atmosphere. For events that vent to the atmosphere, BMPs to minimize or eliminate emissions are required to be followed in addition to meeting the associated records and reports.

See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>49</sup> Please also see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements.

### ***12.6.2 Existing State Requirements***

Comment: Commenter (0776-CDPHE) provides a brief history of the state of Colorado's adopted and later expanded requirements that operators use BMPs to reduce emissions from well liquids unloading and other downhole well maintenance activities, and asks that EPA consider these regulations, particularly standards deemed more stringent – *i.e.*, Colorado's standards on plunger lifts and capture or control of emissions from well liquids unloading and well swabbing activities, once an applicability threshold is met or exceeded. The commenter recognizes that not all methods of liquids unloading lead to emissions to the atmosphere and stresses the fact that Colorado's regulations focus on those liquids unloading activities that do result in the emissions of natural gas. When plunger lifts are used, the commenter notes that under Colorado regulations, smart automation is used to monitor wellhead parameters – tubing and casing pressure, flow rate, and plunger travel time to “optimize plunger operations,” further reducing emissions.

To combat environmental injustice, the commenter (0776-CDPHE) states that Colorado's regulations require/apply a more stringent threshold to well unloading activities occurring in those areas. The commenter writes, the applicability thresholds are based on how frequently wells associated with a well production facility are unloaded or swabbed with emissions to the atmosphere. The commenter adds that they agree with EPA's determination that it may not be feasible in all circumstances to capture or control emissions. The commenter notes that Colorado's regulations do provide an exemption from control where an operator demonstrates to the commenter that control is not technically feasible.

Response I-12-37: The EPA, in the development of the proposed and final requirements for liquids unloading operations, reviewed existing state (including Colorado) and federal regulations and industry voluntary programs that govern liquids unloading activities, in addition to comments received on the proposals. The final standards/presumptive standards reflect many of the elements of regulations and voluntary programs reviewed. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal

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<sup>49</sup> 87 FR 74781-74782.

preamble related to what EPA proposed as constituting a well affected facility/designated facility, and proposed liquids unloading operation requirements.<sup>50</sup> Please also see sections X.F.1 and 3 of the preamble to the final rule which details EPA's final standards related to well affected facilities/designated facilities and liquids unloading requirements.

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<sup>50</sup> 87 FR 74781-74782.

## Chapter 13. Centrifugal Compressors

### 13.1 General Support/Opposition for Proposed Centrifugal Compressor Requirements

Comment: Several commenters (0605-Muscogee (Creek) Nation, 0781-National Tribal Air Association (NTAA), 0391-Keweenaw Bay Indian Community (KBIC)) support the November 2021 proposed requirement to reduce emissions from wet seal degassing systems by 95 percent for existing sources, consistent with the proposed New Source Performance Standards (NSPS).

Conversely, commenter (1375-Kinder Morgan) states that if EPA maintains the November 2021 Proposal to control emissions from existing (as of 2021) wet seals by 95 percent, operators would more than likely be forced to replace wet seals with dry seals due to retrofit technical feasibility issues and costs that would be incurred. The commenter contends that this could have the unintended consequence of increasing emissions, because of the potential for dry seals to emit more pollutants than certain wet seals systems and the embodied energy needed to produce new equipment to replace well-functioning existing equipment. The commenter contends that EPA acknowledges that replacing wet seals with dry seals is an unreasonable outcome.

Response I-13-1: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for this particular (wet seal centrifugal compressor) affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1.b and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>1</sup> Please also see section X.G.1 and X.G.2 of the preamble to the final rule which details EPA's final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards.

Comment: Commenter (0785-John Crane Inc.) supports conversion of oil seals and support systems for selected installations to a dry gas seal. The commenter states that the oil seals would be replaced by dry gas seals utilizing narrow section design (Aura narrow section), which minimizes compressor cavity modification requirements. The commenter notes that gas panel support systems would also be designed for the installations. In general, the commenter states that leaks are reduced typically by 90 percent.

Response I-13-2: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1.b and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>2</sup> Please also see section X.G.1 and X.G.2 of the preamble to the final rule which details EPA's final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards. If an owner or operator of a centrifugal compressor equipped with a wet seal converts their oil seal to a dry gas seal, they would be required to meet the final NSPS OOOOb standards and EG OOOOc

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<sup>1</sup> 87 FR 74791-92, December 6, 2022.

<sup>2</sup> 87 FR 74791-92.

presumptive standards for centrifugal compressors equipped with dry seals, however, the conversion from a wet seal to a dry seal would be allowed under the final rule.

## 13.2 Applicability/Exemptions

Comment: Commenter (0808-American Petroleum Institute (API)) recommends that EPA include special consideration for compressors on the Alaskan North Slope (ANS). Specific issues noted by the commenter include:

- On the ANS there is not a market for natural gas sales.
- Most of the gas that is produced with the oil is separated and then compressed (using large wet seal compressors) to be reinjected back down hole for conservation and enhanced oil recovery.
- The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.
- Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare.

The commenter (0808-API) explains that the ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum/tank, where any remaining entrained gas breaks out and is vented to atmosphere. The commenter's comment letter includes a figure that depicts this process.

In 2010, the commenter (0808-API) provides that EPA's Natural Gas Star program<sup>3,4</sup>, in conjunction with British Petroleum (BP), conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis, according to the commenter, concluded that the sour seal oil degassing design employed on the ANS has greater than 99 percent emission control. The commenter states that this level of emission control is equivalent to a dry gas seal system.

Commenter (0808-API) suggests that, since dry gas seal systems are not subject to the November 2021 Proposal (due to their low leak rate), and the ANS wet seal degassing system design has demonstrated equivalence to dry gas seal systems, wet seal degassing designs employing sour seal oil traps should also not be subject to the rule. The commenter asserts that the two systems are equivalent from a venting perspective and should receive similar treatment under the regulations.

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<sup>3</sup> <https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf>.

<sup>4</sup> <https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoiddegassing.pdf>.



Response I-13-3: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for particular centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1.b and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>5</sup>

The EPA received a similar comment on the December 2022 Supplemental Proposal regarding the ANS wet seal degassing systems being unable, based on technical and cost feasibility issues, to meet the proposed BSER for existing and modified sources. They also provided information supporting their position that the ANS wet seal degassing systems used are inherently low-emitting. EPA's response to this comment is provided at X.G.2.f (Wet Seal Compressors Equipped with a Seal Oil Gas Separation System Utilized on the Alaska North Slope (ANS)) of the final rule preamble.

Comment: Commenters (0465-Jordan Development Company, LLC (JDC), 0946-Michigan Oil and Gas Association (MOGA)) request that EPA listen to the small business industry segment before creating a technically and financially infeasible "one-size-fits-all" approach to regulations based on generalized production modeling and special interest groups. The commenters recommend that EPA continue the exemption of both centrifugal and reciprocal compressors "located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility" as provided in both NSPS OOOO and OOOOa. According to the commenters, well operators visit and service these wells and associated compressors daily to inspect for proper operation, leaks and to conduct maintenance and repairs activities. Any necessary repairs are implemented as soon as possible to avoid product loss and to maximize profit returns. If EPA wishes to propose monitoring for well site compressors, the commenters recommend EPA allow the more feasible and cost-effective monthly auditory, visual, and olfactory (AVO) inspection and documentation, similar to the requirements allowed under 40 CFR 60.5416a.

Response I-13-4: With regards to comments requesting that EPA listen to the small business industry segment before creating a technically and financially infeasible "one-size-fits-all" approach to regulations based on generalized production modeling and special interest groups, see comment response to similar comments in Volume I, Chapter 23, section 23.17 (One-Size Fits All Approach), Response I-23-70.

In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor (and reciprocating compressor) affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>6</sup> The applicability of compressor standards to centralized production facilities does not extend to single well sites. See section XI.G.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

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<sup>5</sup> 87 FR 74791-74792.

<sup>6</sup> 87 FR 74783-92.

Comment: Commenter (1375-Kinder Morgan) believes that compressors in the transmission segment should be treated similar to the compressors located at well sites. The commenter notes that the wet seal proposal applies the existing BSER currently applicable to wet seals under NSPS OOOO and OOOOa to additional affected facilities. The commenter states that this is because EPA relies exclusively on the BSER analysis it undertook for wet seal compressors in the 2015/2016 NSPS OOOOa rulemaking to propose the same controls for the proposed NSPS OOOOb and EG OOOOc. The commenter further notes that EPA excluded centrifugal compressor wet seals located at well sites from the prior rules because there are a small number of wet seals at well sites, and the cost of controlling emissions would not be cost-effective, and EPA carried this conclusion forward in the proposed NSPS OOOOb. According to the commenter the type of controls that would be used on a well site would be the same or similar to those used at a transmission compressor station and that based on the low leak rates and minimal emissions documented (through measurement) from its wet seal centrifugal compressor systems, wet seals in the transmission segment are more similarly situated to those at well sites.

Response I-13-5: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>7</sup> For comments and responses to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

Comment: Commenter (0808-API) requests that EPA clarify the applicability of compressor standards to well sites. The commenter states that the definition proposed for central production facility may extend applicability to compressors located at well sites, which have historically been exempt from the compressor standards. As EPA states they have not updated their cost analyses with new information with respect to well sites, the commenters believe that extending applicability to well sites was not EPA's intent.

Commenter (0923-Lambda Energy Resources LLC (Lambda)) urges EPA to keep the current compressor exemptions shown in both subparts NSPS OOOO and OOOOa stating compressors "located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility."

Response I-13-6: The applicability of compressor standards to centralized production facilities does not extend to single well sites. See section XI.G.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

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<sup>7</sup> 87 FR 74783-92.

## 13.3 BSER Analysis

### *13.3.1 Proposed Wet Seal Centrifugal Compressor Standards*

Comment: Commenters (1375-Kinder Morgan, 0415/1391-Interstate Natural Gas Association of America (INGAA)) state that the November 2021 proposed 95 percent reduction standard is unclear insofar as there is no indication of what value or baseline to which the reduction is to be measured against. The commenter note that the baseline was not identified in development of NSPS OOOO and NSPS OOOOa or in the proposed NSPS OOOOb and the issue was not materially raised by commenters in prior NSPS rulemakings either because the BSER for wet seals did not apply to the transmission segment (NSPS OOOO) or the BSER only theoretically applied to the transmission segment (NSPS OOOOa) because no new wet seals were installed after 2015. A requirement to reduce emissions with an unknown baseline by 95 percent is a wholly different requirement, and the commenters respectfully submits that such proposal is arbitrary and ripe for compliance concerns. The commenters request additional clarity and technical analysis to understand whether and to what extent a 95 percent emissions reduction requirement can and will be achieved, either through control or routing to process.

Response I-13-7: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>8</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

Comment: Commenter (1375-Kinder Morgan) notes that EPA is proposing to require "emissions" be reduced by 95 percent without considering that air, not containing either volatile organic compounds (VOCs) or methane, inherently constitutes part of the emissions stream from wet seals. The commenter states that EPA has conducted no analysis to determine the amount of air contained in potential emissions from wet seals. While the commenter does not have precise data on the amount of air contained in emissions from wet seals, they note that they continue to evaluate this issue. One vendor to the commenter, Solar Turbines, Inc. ("Solar"), has concluded that the emissions from its units are "mostly engine air." According to the Solar analyses, "it is likely that the[ ] flow data represent mostly engine air and that the actual methane emissions are much lower." The commenter contends that, so long as EPA fails to account for the levels of air contained in emissions from wet seals, the 95 percent reduction standard will not only be inaccurate, but it will remain unclear because, as currently written, the standard requires that operators reduce emissions that contain "mostly engine air." Without defining the way in which baseline emissions should be measured or prescribing a method for determining the amount of pollutants contained within overall emissions from wet seals, the commenter asserts that EPA's requirement is impossible to meet.

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<sup>8</sup> 87 FR 74783-74792.

Response I-13-8: The demonstration of 95 percent control is based on a mass emission rate reduction. To demonstrate 95 percent control, the owner or operator must demonstrate that the inlet mass emissions of VOC and methane have been reduced by at least 95 percent at the outlet. Because the calculation is mass-based and not volume-based, the addition of air does not matter in the calculation of percent control efficiency.

Comment: Commenters (1375-Kinder Morgan, 0415/1391-INGAA) state that EPA's estimate of technical feasibility and control costs for existing wet seal centrifugal compressors has not been applied or demonstrated in any real-world application of such controls. Further, the commenters contend that the impact of EPA retroactively applying the wet seal proposal to wet seals existing as of 2021 is significant. Commenter (1375-Kinder Morgan) notes that in total, they operate 197 wet gas seals, 98 of which are manufactured by Solar.<sup>9</sup> They add that all these units were installed prior to 1999, and most of them were installed in the 1980s. The commenter's remaining 99 wet seal centrifugal compressor units consist of 30 different models manufactured by 8 different manufacturers: Clark, Cooper Bessemer, DeLaval, Dresser Rand, Ingersoll-Rand, General Electric, Worthington, and Norwalk. The commenter reports that all these units were installed prior to 2000. They add that all their wet seal compressors were in operation prior to 2015 and after review of the commenter's records, they have confirmed that none of the wet seal centrifugal compressor affected facilities have been modified since 2015 to require control to 95 percent or to be replaced by dry seals. The commenter states that, when installing new units, since 2015, it is their practice to install dry seal centrifugal compressor systems, therefore, the 95 percent reduction standard has not been meaningfully applied by the commenter.

Commenter (1375-Kinder Morgan) states that, because BSER for wet seals may have been required by EPA in certain circumstances since the inception of NSPS OOOO, the same commenter conducted independent due diligence to understand how operators are effectively applying the existing 95 percent reduction requirements under NSPS OOOOa. The commenter engaged with multiple trade associations and other midstream operators, including operators of gathering and boosting compressor stations as well as natural gas processing plants. The commenter found that no midstream operator was able to share experience in effectively controlling or capturing a wet seal system by 95 percent.

Commenter (1375-Kinder Morgan) further states that EPA has not published any data or technical analysis describing the extent to which the current BSER for wet seals is implemented and cost-effective. Given the lack of application of what EPA suggests is BSER, the commenter states that it is apparent that EPA has not comprehensively evaluated the existing standard to determine whether it is an effective, reasonable, and cost-effective measure, and whether it should remain BSER for existing sources. The existing requirement in NSPS OOOOa appears to be largely theoretical because virtually all seals installed in the midstream and transmission segments since 2015 have been dry seals. This foundational issue of clarifying a 95 percent reduction requirement is a crucial one if EPA is to adopt a workable standard.

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<sup>9</sup> Solar models operated by Kinder Morgan (the commenter) include: the Saturn, Centaur 40, Centaur 50, and Taurus 60.

Response I-13-9: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>10</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

Comment: Commenter (0415/1391-INGAA) states that to provide transparency for EPA's evaluation, EPA should include in the record of the supplemental notice a new Technical Support Document (TSD) (or technical memorandum) that presents EPA's analysis within one document rather than citing two previous TSDs, and that clearly and transparently states all assumptions associated with the calculations.

Response I-13-10: See EPA-HQ-OAR-2021-0317-1578 "2022 Supplemental Proposal Oil and Natural Gas Sector NSPS and EG Technical Support Document and Supporting Spreadsheets."

Comment: Commenter (0415/1391-INGAA) states EPA needs to reevaluate its BSER evaluation, for existing wet seal centrifugal compressors (the only kind that exists, actually, since no one is constructing new wet seal compressors). EPA should not rely on calculations that are not transparently provided in the record for the rulemaking, and EPA should not rely on current cost estimates for NSPS OOOOa proposed controls at existing wet seal compressors.

Response I-13-11: In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>11</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

### ***13.3.2 Emissions***

Comment: Commenters (0415/1391-INGAA, 1375-Kinder Morgan) assert that actual wet seal centrifugal compressor baseline emissions are significantly lower than the emissions estimates that EPA used in the November 2021 Proposal's BSER analysis, and they recommend that EPA use updated emissions information reported under GHGRP subpart W. According to one commenter (0415/1391-INGAA), the emission factor for wet seal compressors for previous NSPS OOOO and NSPS OOOOa analyses is more than five times higher than the updated compressor emission factor, which EPA itself recognized and adopted in 2016.

The commenters (0415/1391-INGAA 1375-Kinder Morgan) note that a recent paper published by Pipeline Research Council International, Inc. (PRCI) provides a current best-estimate of

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<sup>10</sup> 87 FR 74783-74792.

<sup>11</sup> 87 FR 74783-74792.

transmission and storage compressors emissions, to update emission estimates in the EPA Annual GHGRP inventory report, and to provide EPA with an analysis of measured compressor emissions for Subpart W.<sup>12</sup> The commenters provide that the paper compiled hundreds of measurements for wet seal compressor methane emissions between 2011 and 2016. The analysis found emissions from centrifugal units with wet seal systems were approximately 7,730 standard cubic feet (scf) of natural gas per day—vastly lower than historical estimates. The detailed results presented in the PRCI report show a composite wet seal compressor emission factor 85 percent lower than the inflated, circa 2010-2015 emission factor used by EPA in the TSD, with the emissions specific to the regulated source (degassing vent) over 90 percent lower.

Commenter (1375-Kinder Morgan) provides information on wet seal centrifugal compressor emissions for their equipment in the transmission segment and requests EPA to consider using it in any new BSER analysis. The commenter states that they conducted extensive analysis of its existing data to evaluate potential emissions from its wet seals and dry seals.<sup>13</sup> The commenter reviewed actual measurement data—leak rate, in standard cubic feet per minute (scfm)—from all of its wet and dry seal units, the data covering the period of 2017 through 2021. The data set is comprised of over 520 measured data points. According to the commenter, of its 197 wet seal units, the commenter has 223 measured data points for leak rate across 112 units. Where measured data for a particular unit was not available, the commenter calculated an average leak rate based on all documented measurements sourced from that particular model. If the commenter did not have measured data for a specific model, they conservatively applied the average of all measured data as the leak rate. For the latter, the commenter reports that this generic average was only applied to 10 wet seal units. A few critical summary points include the following:

- The average leak rate for all wet seal units was 0.46 scfm.
- The maximum measured leak rate was scfm, and the minimum leak rate was 0 scfm.
- Further parsing this data, 46 of the 112 wet seal units that were tested had a 5-year average of 0 scfm.
- Only 7 of the 112 wet seal units with measured data had one or more data points over 3 scfm over the last 5 years.
- Conservatively applying the maximum leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation,<sup>14</sup> the total cubic feet of gas leaked for all 197 units is approximately 80,558 smcf for a single year, and the average is 409 smcf per unit.

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<sup>12</sup> See T. McGrath et al., PRCI White Paper: Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data, at 47, Tbl. 4-1, Catalogue No. PR-312-18209-E01 (Oct. 17, 2019), available for purchase at <https://www.prci.org/Research/CompressorPumpStation/CPSPProjects/CPS-17-01A/142206/171289.aspx>.

<sup>13</sup> We refer the reader to Section VI of the comment letter for a summary of Kinder Morgan's measured data related to dry seals.

<sup>14</sup> Assuming 8,760 hours of operation is conservatively high. These wet seals will only have a leak rate when in operation, and they do not operate 8760 hours.

The commenter (1375-Kinder Morgan) states that they then applied the same methodology EPA applied in the November 2021 Proposal to determine the estimated tons-per-year (tpy) of VOC and methane, per unit:<sup>15</sup>

- Conservatively applying the max leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation, for all 197 units the total methane emissions are estimated at 1,677 tpy, and 8.5 tpy methane per unit.<sup>16</sup>
- Conservatively applying the max leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation, for all 197 units the total VOC emissions are estimated at 46 tpy, and 0.23 tpy VOC per unit.

Commenter (1375-Kinder Morgan) notes that EPA estimates indicate that the baseline uncontrolled emissions for each individual centrifugal wet seal compressor at transmission compressor stations to be 157 tpy methane and 4.3 tpy VOC. The commenter estimates that the baseline uncontrolled emissions for each of their companies' individual centrifugal wet seal compressors are 8.5 tpy methane and 0.41 tpy VOC, with an average leak rate of 0.46 scfm. Notably, the commenter states that most of the measured flow rates for wet seal compressors are lower than EPA's estimated flow rate for dry seal compressors of 6 scfm. In fact, of the commenter's 233 measured data points taken on wet seals across 112 units, only 2 units and a total of 4 data points were above 6 scfm. According to the commenter, these low emissions can be attributed to the companies' practice of maintaining its wet seals to the point that their emissions are comparable to or less than dry seals.

According to the commenter (1375-Kinder Morgan), the key points to takeaway are that: the commenters wet seals are a minimal source of methane emissions (based on conservative estimates<sup>17</sup>), and an insignificant source of VOC emissions, based on conservative estimates; reducing those values even further, let alone by 95 percent, would be cost prohibitive and potentially technically infeasible, particularly considering that much of the leak rate may be comprised of air, and not regulated pollutants; and finally, a well-maintained wet seal functions just as well if not better than a dry seal.

Response I-13-12: In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER using GHGRP subpart W emissions information and

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<sup>15</sup> 86 Fed. Reg. at 63,221 ("The wet-seal centrifugal compressor methane uncontrolled emission factors are based on the volumetric emission factors used for the GHGI, which were converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. The VOC emissions were calculated using the ratio of . . . 0.0277 pounds VOC per pound of methane for the transmission and storage segment.").

<sup>16</sup> These tpy calculations assume that the entire stream is emissions. However, as noted above, some significant percent of this stream could be merely *air* and not pollutants.

<sup>17</sup> The commenter (Kinder Morgan) recognizes that EPA also has public data submitted by the commenter and other operators regarding wet seals as a part of the GHGRP. The commenter submits that the data analysis that they summarize above is a better source of data (as compared to the Subpart W data points) for this particular analysis for the following reasons: The analysis above is more (1) comprehensive than the commenter's Subpart W data, as Subpart W includes reporting thresholds, which does not capture all of the commenter's wet seals; (2) accurate, because the commenter used measured data rather than application of an average factor; and (3) conservative, because the commenter applied a worst case scenario, assuming the highest measured leak rate at 8,760 hours of operation.

proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>18</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

### ***13.3.3 Cost and Cost Effectiveness***

Comment: Commenter (1375-Kinder Morgan) states that the BSER for wet seal centrifugal compressors in the transmission segment is a proposed regulatory approach for reduction of methane, with potentially only limited VOC co-benefits. The commenter indicates that they evaluated gas composition at five transmission compressor stations in support of this point. The data was gathered over a period of a year (July 2020 to July 2021) from gas chromatographs (GCs). The GCs continuously monitor the commenter's natural gas at all receipt points, some delivery points, and other key junctures along the transmission system. The GCs take approximately three samples every hour, which are then averaged to get one numerical block-hour average. The average VOC content evaluated was less than 1 percent and can be as low as 0.0206 percent.

Response I-13-13: In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>19</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

Comment: Commenters (1375-Kinder Morgan, 0415/1391-INGAA) state that the costs used by EPA in the November 2021 Proposal's BSER analyses were not representative of actual costs, and that EPA had significantly underestimated the costs for the control options evaluated. The commenters note that in essence, EPA used figures it developed from previous, and historic rulemakings and updated those figures to account for inflation. However, according to the commenters the earlier figures are unreliable, not vetted by EPA, and clearly underestimate the costs associated with wet seal emissions control or capture.

The commenters (1375-Kinder Morgan, 0415/1391-INGAA) add that in developing NSPS OOOO, EPA found that the costs for the centrifugal compressor wet seal capture system and determined a system of this type, in which the seal oil degassing vents are routed to fuel gas, compressor suction or an existing flare would cost \$22,000. The commenters report that the estimated cost includes an intermediate pressure degassing drum, new piping, gas demister/filter and a pressure regulator for the fuel line. In 2016, EPA updated these costs. Where a facility already has a flare installed, EPA estimated capital costs to be \$23,252 for routing a wet seal

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<sup>18</sup> 87 FR 74783-74792.

<sup>19</sup> 87 FR 74783-74792.



fluid degassing system to a process. To install a new control device, EPA estimated capital costs of \$71,783.

Commenters (1375-Kinder Morgan, 0415/1391-INGAA) state that in evaluating costs associated with the November 2021 Proposal for wet seals, EPA did not undertake new cost analysis necessary to confirm whether cost-estimates were accurate based on actual data; the agency simply adjusted values for inflation. The commenters found this approach highly problematic insofar that EPA's 2015 estimates are largely theoretical because BSER has not been applied under NSPS OOOOa for existing wet seal centrifugal compressors in the transmission segment. Further the commenters were concerned that EPA based its cost-benefit analysis on the 2010/2011 NSPS OOOO and 2016 NSPS OOOOa is not accurate since those analyses did not use the updated emissions factor for wet seal compressors, which is applied in the GHGRP. Commenter (0415/1391-INGAA) adds that, it appears that there are errors in the analysis, or EPA has included assumptions or calculation corrections that are not apparent or stated.

The commenters (1375-Kinder Morgan, 0415/1391-INGAA) contend that using inflated emissions factors overestimates the emissions as compared to the costs. One of the commenters (1375-Kinder Morgan) provided detailed cost information that they stated was more representative of actual costs for three combustion scenarios, the option to route to a process for control, and retrofit costs. [See sections 13.3.2.1 and 13.3.2.2 below]

Response I-13-14: In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>20</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

#### 13.3.2.1 Routing to a control device

Comment: Commenter (1375-Kinder Morgan) provides detailed cost information that they state was more representative of actual costs for three combustion scenarios. Based on vendor quotes the commenter estimates the cost of installing a flare, as well as both a "low end" and a "high end" for the cost of routing emissions from the wet seal compressor to an enclosed combustion device. According to the commenter, the cost of the flare would consist of the equipment (\$120,000), piping (\$5,000), and contractor labor, installation, and civil/structural engineering consultation (\$60,000). However, the commenter does not believe that the flare is likely to be an effective control technology in this context. The costs for the enclosed combustion device would consist principally of the cost of a combustor, panel, and knockout vessel (\$40,000 - \$79,000); piping to assist gas as well as waste gas header pipe (\$5,000); and contractor labor, installation, and civil/structural engineering consultation (\$60,000). In Table 1 of their comment letter, included as Table 13-1 below, and using EPA cost calculation methodologies, the commenter

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<sup>20</sup> 87 FR 74783-74792.

summarizes its estimated costs-per-ton to apply the wet seal centrifugal compressor proposal by controlling methane emissions by 95 percent.

Table 13-1. Kinder Morgan Cost-Effectiveness Analysis for Control of Wet Seals by 95% in the Transmission Segment

| Control Equipment         | Pollutant | Capital Cost | Total Annual Cost* | Emission Reduction | Cost Effectiveness |
|---------------------------|-----------|--------------|--------------------|--------------------|--------------------|
|                           |           | (\$)         | (\$)               | (TPY)              | (\$/ton reduced)   |
| <b>Combustor low-end</b>  | Methane   | \$105,000    | \$136,310          | 8.08               | \$16,880           |
| <b>Combustor high-end</b> | Methane   | \$144,000    | \$143,422          | 8.08               | \$17,761           |
| <b>Flare</b>              | Methane   | \$185,000    | \$150,900          | 8.08               | \$18,687           |

According to the commenter (1375-Kinder Morgan), whether they were to pursue control, neither proposed regulatory approach is cost-effective, by EPA's own measure. Further, EPA's cost-effectiveness conclusions are mistaken or outdated; first because very few if any transmission operators have been required to apply the 2016 NSPS OOOOa BSER to wet seals and second, because the actual data evaluated demonstrates that EPA underestimated costs and overestimated emissions. The commenter notes that the result is that the cost-per-ton of methane reduced is well above \$2,185/ton, let alone the previous estimate of \$1,093/ton. In conclusion, the commenter's analysis indicates that it is categorically cost prohibitive to implement EPA's proposed BSER to capture or control wet seal centrifugal compressors by 95 percent in the transmission segment.

Response I-13-15: In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal with consideration of the costs provided by the commenter. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>21</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

#### 13.3.2.2 Routing to a process

Comment: Commenter (1375-Kinder Morgan) states that EPA misstates the complexity of the re-routing process in general and significantly underestimates the costs of routing to process. The

<sup>21</sup> 87 FR 74783-74792.

commenter reports on research they conducted to determine what technologies might exist for the proposed capture and has identified one (and only one) potential capture technology; however, this technology remains untested for wet seals. Based on information from the third-party vendor, the commenter reports that the costs to route to capture include the cost of equipment (\$400,000) and contractor labor, installation, and civil/structural engineering consultation (\$300,000). According to the commenter, these costs are conservatively low because they do not include the cost of re-routing electrical infrastructure that could be required to power the new equipment, or in the alternative, the cost of installing a new engine, as applicable. In Table 13-3, below, and using the EPA methodologies, the commenter summarizes its estimated costs-per-ton to apply the wet seal centrifugal compressor proposal by capturing methane emissions by 95 percent and routing to process.

Table 13-3. Kinder Morgan Cost-Effectiveness Analysis for Capture of Wet Seals by 95% in the Transmission Segment

| Control Equipment | Pollutant | Capital Cost | Total Annual Cost* | Emission Reduction | Cost Effectiveness |
|-------------------|-----------|--------------|--------------------|--------------------|--------------------|
|                   |           | (\$)         | (\$)               | (TPY)              | (\$/ton reduced)   |
| Recapture system  | Methane   | \$700,000    | \$244,824          | 8.50               | \$28,803           |

According to the commenter (1375-Kinder Morgan), whether they were to pursue control, neither proposed regulatory approach is cost-effective, by EPA's own measure. Further, EPA's cost-effectiveness conclusions are mistaken or outdated; first because very few if any transmission operators have been required to apply the 2016 NSPS OOOOa BSER to wet seals and second, because the actual data evaluated demonstrates that EPA underestimated costs and overestimated emissions. In conclusion, the commenter's analysis indicates that it is categorically cost prohibitive to implement EPA's November 2021 proposed BSER to capture or control wet seal centrifugal compressors by 95 percent in the transmission segment.

**Response I-13-16:** In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal with consideration of the costs provided by the commenter. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>22</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

<sup>22</sup> 87 FR 74783-74792.

#### 13.3.2.3 Converting Wet Seals to Dry Seals

Comment: Commenter (1375-Kinder Morgan) states that they evaluated the cost to convert wet seals to dry seals. According to the commenter, the conversion would require upgrading the compressor, upgrading control systems, making skid modifications, procuring the necessary interconnect hardware, and installing and commissioning labor. The commenter reports that the conversion would total approximately \$1,400,000 per Solar unit, and \$1,250,000 per non-Solar unit, making the overall cost approximately \$260,950,000 for the wet seal units the commenter operates. The commenter asserts that, on a cost-per-ton basis, the result would not be reasonable. This is because, as described in the commenter's data analyses regarding wet seals and dry seals, the leak rates and potential emissions from its dry seals are comparable to the commenter's well-maintained wet seals.

The commenter (1375-Kinder Morgan) notes that there are also technical concerns associated with converting wet seals to dry seals, which could generate additional costs. For instance, the commenter states that one of the benefits of a wet seal system is that it maintains built-in damping for the compressor seals to limit or eliminate vibrations. When the unit is converted to a dry seal, this damping benefit is lost. As a result, the commenter would need to evaluate the converted system and potentially make other modifications to the compressor to avoid unsafe vibration issues and EPA would need to take these costs into account in its analysis. Consistent with its own analysis, the commenter requests that EPA modify the wet seal centrifugal compressor November 2021 Proposal as described herein to avoid an inappropriate standard outcome (*i.e.*, changing of wet seals to dry seals).

Response I-13-17: The EPA appreciates the cost and technical information provided by the commenter. The EPA has not proposed or included requirements in the final NSPS OOOOb standards and EG OOOOc presumptive standards to convert wet seals to dry seals.

#### 13.3.2.4 Maintenance and Repair Activities to Meet Numerical Emission Limit

Comment: Commenters (1375-Kinder Morgan, 0415/1391-INGAA) state that low emissions from centrifugal compressors equipped with wet seals are largely a function of proper maintenance and that requiring a 95 percent reduction standard or routing to a process creates an unintended result—the more careful an operator is with maintaining its wet seals, the more difficult and costly (on a cost-per-ton basis) controlling emissions in compliance with these requirements becomes.

Commenter (1375-Kinder Morgan) notes that their company institutes an annual monitoring plan and indicate that actions needed to reduce emissions or maintain a compressor such that it is low-emitting can range from correcting an identified issue immediately with minor maintenance, replacing O-rings on the filtration system, or having to rebuild the entire oil system. The commenter indicates that the implementation of such a program has resulted in average measured emissions of less than 0.5 scfm for compressors with wet seals.

Commenter (0415/1391-INGAA) recommends that the rule for existing compressors provide a procedure that would allow owners or operators to demonstrate that a particular wet seal configuration results in no or very small degassing emissions (for example, less than 3 scfm) per wet seal,<sup>23</sup> which is half the average emission rate for dry seal compressors (6 scfm), which EPA found too small to regulate previously) and thus be excluded from the control requirements for high-emitting wet seals under NSPS OOOOb and EG OOOOc. Another commenter (1375-Kinder Morgan) suggests that EPA consider an approach similar to that advocated by California Air Resource Board (CARB) in the California Greenhouse Gas Emissions Regulation. Pursuant to that regulation, “[a] compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired within 30 calendar days of the initial flow rate measurement.” Whereas EPA mandates control of all wet seals, the commenter states that CARB’s rule focuses only on wet seals with emissions greater than 3 scfm. The commenter suggests that EPA could similarly adopt a scfm limit at above which a wet seal would need to be captured/controlled. Alternatively, they suggest that EPA could establish of an emissions applicability threshold where a wet seal compressor that has a measured flow rate less than a specified threshold would be exempt from regulatory requirements.

However, the commenter (1375-Kinder Morgan) cautions that further evaluation is required to understand the impacts and cost-effectiveness of the CARB proposal as applied to existing wet seal centrifugal compressors in the transmission segment. Specifically, the commenter states that EPA must continue to evaluate the various types of repairs that may be required, and the associated cost of repair, including the cost-per-ton of methane reduced and EPA must understand the timelines required for the necessary repairs or replacements.

The commenters (1375-Kinder Morgan, 0415/1391-INGAA) suggest that a threshold monitoring option is a more practical option for low-emitting centrifugal compressors with wet seals (as compared to the proposed requirement to route to a control device or to a process).

Response I-13-18: In response to comments received on the November 2021 Proposal, EPA re-evaluated the November 2021 BSER for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal with consideration of the commenters’ recommendations. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal preamble.<sup>24</sup> For EPA’s response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) of this Response to Comment Document (hereinafter referred to as the RTC) and section XI.G of the final rule preamble. The EPA determined that implementing a volumetric flow rate standard for existing wet seal centrifugal compressors that would be subject

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<sup>23</sup> The commenter notes that CARB recently issued a regulation that set forth a 3 scfm threshold for emissions from each wet seal at a centrifugal compressor as an alternative to controls similar to what is required in the Proposed Rule (*i.e.*, vapor collection and flaring or routing to a process). See CAL. CODE REGS. tit. 17, § 95668(d)(6) (requiring wet seal compressors *either* to install controls similar to OOOOa—*i.e.*, vapor recovery with degassing emissions routed to a flare or a process—or annual monitoring and repair where the leak rate is more than 3 scfm per wet seal).

<sup>24</sup> 87 FR 74783-74792.

to the EG OOOOc presumptive standards is BSER for the control of methane for the gathering and boosting, processing, and transmission and storage segments.

### ***13.3.4 Low emitting wet seal compressor designs***

Comment: Several commenters (0415/1391-INGAA, 0599-Marcellus Shale Coalition (MSC), 0782-Berkshire Hathaway Energy Company (BHE), 1375-Kinder Morgan) report that the process for wet seal degassing varies throughout the industry, and some manufacturers have a configuration that is essentially a closed process that ports the degassing emissions into the natural gas line at the compressor suction. According to the commenters, this type of wet seal centrifugal compressor configuration typically includes a primary chamber where initial degassing occurs (and is recovered), and chamber(s) with air sparging to release and recover residual gas volumes entrained in the oil. Rather than venting all the de-gassing volumes, the commenters note that the emissions are routed back to suction directly from the degassing/sparging chambers; the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. The commenters state that field evaluation is not always feasible for this closed system configuration but reports that testing and modeling demonstrates that the residual natural gas volume vented is very small (much less than 1 percent of the total degassed natural gas volume). The commenters also note that for seals that emit *de minimis* levels of VOC or methane, it would be impracticable to further reduce such emissions and that assuming emissions can be calculated, the proposed BSER of routing emissions to a control device or to a process would be cost prohibitive.

Commenter (0782-BHE) states that the issues related to these low-emitting or self-contained wet seal compressors have not been resolved in NSPS OOOOa rulemakings because there were no or very few affected facilities and thus the issue was a low priority. However, the commenter states that the EG OOOOc requirements would affect hundreds of existing centrifugal compressors with wet seals in the transmission and storage (T&S) segment. The commenter states that most of centrifugal compressors with wet seals (e.g., manufactured by Solar) employ the low emitting technology.

Commenter (0415/1391-INGAA) suggests that EPA make clear that these types of compressors already incorporate one of the control options required under the November 2021 Proposal, namely collection and routing to a process and inclusion of appropriate language in the rule to address emissions that are predominantly recirculated.

Commenters (1375-Kinder Morgan, 0782-BHE) request that EPA clarify that certain existing closed-loop wet seal systems be exempt from any regulatory proposal, or at a minimum, that such systems should be considered in compliance with the BSER currently applicable to wet seals.

Response I-13-19: See section IV.G.b.ii (Lower-Emitting/Self-Contained Wet Seal Compressor Designs) of the December 2022 Supplemental Proposal preamble<sup>25</sup> for EPA's response to these

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<sup>25</sup> 87 FR 74787-74788.

comments. See also section XI.G of the final rule preamble for a summary of the final centrifugal compressor requirements.

### ***13.3.5 Mechanical Seal Compressors***

Comment: Commenter (0415/1391-INGAA) states that another type of low-emissions wet seal utilized in compressors in the transmission and storage sector is a mechanical seal, in which metal (tungsten carbide) is seated against carbide, with oil pressing against the outside of the actual seal. One such mechanical wet seal is manufactured by Kaydon and utilized on DeLaval compressors. (Information for the Kaydon mechanical wet seal is provided in Attachment 7 of the comment letter.) Because the oil is not in contact with the natural gas, the commenter explains that these wet seals have generally zero degassing emissions. According to the commenter, it makes no sense to subject such a zero-emissions wet seal to control requirements. Accordingly, EPA should exclude compressors utilizing mechanical wet seals from the requirements otherwise applicable to wet seal compressors.

Response I-13-20: The EPA stated in the December 2022 Supplemental Proposal that the EPA is continuing to evaluate mechanical wet seal designs and the comments it has already received on the issue and solicited additional information on these and other wet seal compressor designs (with supporting emissions information) that are inherently low-emitting under operating conditions. See discussion in section IV.G.1.b.ii. of the December 2022 Supplemental Proposal preamble.<sup>26</sup> The commenter provided additional information on mechanical seals for EPA's consideration in their comments on the December 2022 Supplemental Proposal. See EPA's response based on additional information provided by the commenter in Volume II, Chapter 10, section 10.2.1, Response II-10-14 of this RTC, and section XI.G.4 (Other inherently low-emitting compressor with wet seal configurations) of the final rule preamble.

See also section XI.G of the final rule preamble for a summary of the final centrifugal compressor requirements.

### ***13.3.6 Low-Utilization Wet Seal Compressors***

Comment: Commenters (1375-Kinder Morgan, 0415/1391-INGAA, 0599-MSD) suggest that EPA consider a *de minimis* exemption, such as an exemption for limited use wet seal centrifugal compressors (*i.e.*, peak flow that operate infrequently). Commenter (0415/1391-INGAA) notes that 60 percent of its wet seal fleet fits this category. The 3-year average (covering years 2019-2021) of operating time for these wet seal compressors is 31 operating hours per year per compressor (utilization of 0.36 percent). By their nature, these limited-use compressors result in minimal actual emissions of methane and VOC; therefore, imposing control requirements for these units has an astronomical \$/ton value that is far beyond what would be considered reasonable. The commenter proposes a cutoff for such a *de minimis* exemption at 500 hours of operation per year, based on a 3-year average of actual operation. Another commenter (1375-Kinder Morgan) states they would support an exemption for wet seal centrifugal compressors

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<sup>26</sup> See 87 FR 74788.

that operate for less than 500 hours per year, with a requirement to come into compliance within 180 days of exceeding 500 hours.

Response I-13-21: The EPA has not included a *de minimis* exemption in the December 2022 Supplemental Proposal or final rule requirements for wet seal centrifugal compressors in the NSPS OOOOb and EG OOOOc. While the EPA has not included a *de minimis* exemption for limited use wet seal centrifugal compressors, the final centrifugal compressor requirements in both the NSPS OOOOb and EG OOOOc provide alternative standard options for lower-emitting/self-contained wet seal compressor designs in addition to other compliance alternatives (e.g., routing to a process or control device).

Additionally, in response to these and other comments received on the numerical emission limit standard and limited-use centrifugal compressors, EPA proposed in the December 2022 Supplemental Proposal to allow owners and operators to conduct periodic reciprocating compressor flow rate monitoring based on the hours of operation (*i.e.*, 8,760 hours) in lieu of requiring monitoring based on a calendar year. For details, please see discussion in sections IV.G.1.b.i and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>27</sup> Please also see sections X.G.1 and X.G.2 of the preamble to the final rule which details EPA's final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards.

### ***13.3.7 Retrofit of Existing Wet Seal Centrifugal Compressors for 95% Reduction***

Comment: Commenters (0415/1391-INGAA, 1375-Kinder Morgan) express concern about having to retrofit existing wet seal centrifugal compressors to accommodate the November 2021 Proposal requiring owners and operators to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater. The commenters note that EPA over-simplifies what would be required to install combustion control or route to process, therefore, underestimates the associated technical feasibility and costs.

Commenter (1375-Kinder Morgan) states that the November 2021 Proposal for wet seal centrifugal compressors would require installation of an enclosed combustion device or a process flare in nearly every case as there are presently no flares or combustors located at their sites. The commenter notes that control is rarely needed at transmission sites and where control is required, the commenter would apply selective catalytic reduction as the relevant control technology instead of combustion. The commenter notes that, while theoretically an enclosed combustion device could be installed to control the minimal emissions on an individual wet seal compressor, a combustion device cannot be located just anywhere, especially not in close proximity to a transmission compressor station. The commenter further notes that a combustion device must be strategically located away from combustible materials, which typically requires a significant footprint, aboveground piping (above roadways), and in an elevated location. In addition, the commenter reports that, in order to install such a device, they would likely have to apply for and receive state and local permit modifications, which are not certain to be approved in each case.

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<sup>27</sup> 87 FR 74783-74788, 87 FR 74791-74792.



The commenter (1375-Kinder Morgan) also states that routing to a control device could present safety concerns. For example, they note that attempts to capture a low-pressure natural gas vent stream, such as that of the wet seal, could result in inducing air into the gas stream, potentially creating a combustible mixture. The commenter reports that one manufacturer has previously “caution[ed] the use of flaring with gas seal vented emissions due to risk of the potential explosive hazard and back-flashing and serious risk of explosion.” At least one manufacturer (Solar) discourages flaring for this reason although some customers have successfully implemented it.

With respect to the routing to process option, the same commenter (1375-Kinder Morgan) notes that, while theoretically feasible, it would require a substantial revision to the existing process, and likely significant reconfiguration of the site. The commenter notes that the limited emissions, on average, approximately 0.46 scfm, are at a significantly lower pressure than the wet gas line. As a result of this significant disparity, to route emissions from a wet seal back to a process, the commenter reports that it would be required to (1) develop a process to ensure as much air as possible is removed from the gas stream; and (2) recompress that gas stream from a very low pressure (nearly atmospheric) to a much higher pressure, roughly 1,000 psi. To recompress the emissions stream to then re-introduce it back to process, the commenter states that they would be required to install an entirely new piece of equipment, which could require either a natural gas fired engine or a motor. The potentially available technologies for application to wet seals are untested by the commenter, and largely untested across the industry. They state that, a low flow gas stream cannot be safely or technically re-introduced back into their processes without significant, and resource-intensive attention to that minor emissions stream. According to the commenter, the unintended result would be that the additional equipment that would need to be installed to accomplish this routing back to process would not only be costly but could also result in additional emissions from other sources.

Commenters (0415/1391-INGAA, 1375-Kinder Morgan) state that EPA has not evaluated actual retrofits of a wet seal centrifugal compressor to understand the demonstrated and practical consequences of its proposal. Further, the commenters state that the costs of retrofitting transmission stations with combustion devices is significant and cannot be readily dismissed.

Response I-13-22: In response to comments received on the November 2021 Proposal, EPA proposed a different BSER for existing wet seal compressors in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.G.1.b and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>28</sup> Please also see section X.G.1 and X.G.2 of the preamble to the final rule which details EPA’s final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards. Based on the updated analysis presented in the December 2022 Supplemental Proposal, the EPA is finalizing that the presumptive standard of performance for existing sources is a volumetric flow rate of 3 scfm per seal; and BSER is for an owner or operator to conduct preventative maintenance and repair of their centrifugal compressors that use wet seals, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a wet seal at or below 3 scfm per seal.

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<sup>28</sup> 87 FR 74783-74788, 87 FR 74791-74792.

### ***13.3.8 Dry Seal Compressor Emissions and Standards***

Comment: Commenter (1375-Kinder Morgan) states that based on their data and experience, in many cases, a wet seal and a dry seal may have the same or similar emissions impact. The commenter estimates that the baseline uncontrolled emissions for each of its individual centrifugal wet seal compressors are 8.5 tpy methane and 0.41 tpy VOC, with an average leak rate of 0.46 scfm. Similar to the analysis conducted by commenter regarding wet seals, the commenter undertook extensive analysis of its existing measured data points for its dry seals. In particular, the commenter reviewed actual measurement data (leak rate, in scfm) from all of its dry seal units, the data covering the period of 2017 through 2021. The commenter reports that they have 290 measured data points across 147 (of a total 233) dry seal units. Where measured data for a particular unit was not available, the commenter calculated an average leak rate based on all documented measurements sourced from that particular model. If the commenter did not have measured data for a specific model, the commenter conservatively applied the average of all measured data as the leak rate. For the latter, the commenter notes that this generic average was only applied to 17 dry seal units. A few critical summary points provided by the commenter include the following:

- The average leak rate for all dry seal units was 0.76 scfm.
- The maximum measured leak rate was 8.74 scfm, and the minimum leak rate was 0 scfm.
- Further parsing this data, 93 of the 147 dry seal units that were tested had a 5-year average of 0 scfm. 223 of the 290 data points measured were 0 scfm.
- A total of 18 of the 147 dry seal units with measured data had at least one data point over 3 scfm over the last 5 years.
- Conservatively applying the maximum leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation, [Assuming 8,760 hours of operation is conservatively high. These dry seals will only have a leak rate when in operation, and they do not operate 8,760 hours.] the total cubic feet of gas leaked for all 223 units is approximately 122,070 smcf for a single year, and the average is 557 smcf per unit.

The commenter (1375-Kinder Morgan) states that they then applied the same methodology EPA applied in the November 2021 Proposal to determine the estimated TPY of VOC and methane, per unit.

- Conservatively applying the max leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation, for all 223 units the total methane emissions are estimated at 2890 tpy, and 11.6 tpy per unit.
- Conservatively applying the max leak rate for each unit over the past 5 years, and assuming 8,760 hours of operation, for all 223 units the total VOC emissions are estimated at 70 tpy, and 0.32 tpy per unit.

The commenter (1375-Kinder Morgan) notes that it is critical to develop a defensible and reasonable methodology for emissions calculations, recognizing that in most cases, the flow data likely represent mostly engine air. While the commenter is willing to engage with EPA on this

issue, the commenter provides that adopting the existing BSER for dry seals is not a feasible or desirable outcome.

Commenter (0844/0845-Environmental Defense Fund (EDF) *et al.*) suggests that EPA consider standards to reduce emissions from dry seal centrifugal compressors.

Response I-13-23: In response to comments received on the November 2021 Proposal, EPA proposed a 3 scfm per seal numerical standard for dry seal compressors for both new and existing dry seal compressors in the December 2022 Supplemental Proposal. Please see discussion in sections IV.G.1.b.iii and IV.G.2.b of the December 2022 Supplemental Proposal preamble.<sup>29</sup> The EPA received a lot of comments on the December 2022 Supplemental Proposal and BSER analyses proposed for dry seal compressors. In response to comments received on the December 2022 Supplemental Proposal, the EPA revised the proposed 3 scfm per seal numerical standard for dry seal compressors for both new and existing dry seal compressors in the final rule. Please see discussion in sections XI.G.1 of the preamble to the final rule. Please also see sections X.G.1 and X.G.2 of the preamble to the final rule which details EPA's final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards.

### **13.4 Other-Compressor Exhaust**

Comment: Commenter (0844/0845-EDF *et al.*) suggests that EPA develop standards to reduce emissions from compressor exhaust. The commenter estimates 393,355 tons of methane emissions resulting from gathering and boosting compressor exhaust in 2019. The commenter notes that as they have recommended to EPA in the past, EPA should consider requiring that compressors be driven by turbines or electric motors, since according to emissions factors in the GHGI, turbines produce less methane per horsepower-hour than reciprocal internal combustion engines (RICE) by about a factor of 25.<sup>30</sup>

Response I-13-24: Emissions from the engines used to power the compressors are not within the scope of this regulation.

### **13.5 Other Emission Reduction Systems**

Comment: Commenter (0785-John Crane Inc.) provides information regarding emission reduction systems developed by the commenter. Using products such as the commenter's AuraTM family of seals, the commenter can convert wet seals to dry gas seals to stop methane leakage. The Aura Zero-Emissions seal eliminates nearly all emissions from seals. The commenter states they have an expertise in overhauling complex pump and compressor systems to reduce emissions, while increasing efficiency and usage of products for producers. Various scenarios in oil and gas production often require varying solutions. The commenter recommends allowing for all solutions below in order to best account for particular compressor stations:

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<sup>29</sup> 87 FR 74788-74789, 87 FR 74792.

<sup>30</sup> Sierra Club *et al.*, Comments on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO, 48 (Nov. 30, 2011).

- When compressor can't be stopped and seals be retrofitted, the commenter proposes recovering methane emissions from dry gas seals. Leakage recovery system will allow to incorporate expected leakage during seal operation into compressor inlet. Emissions from primary vent will be processed and pressurized to be returned to compressor inlet.
- When applicable, the commenter proposes conversion of standard dry gas seals into the commenter's patented zero emission dry gas seal. This revolutionary new design incorporates upstream pumping technology to pressurize an inert gas to a pressure level sufficient to direct the inert gas into the compressor discharge. This approach prevents process gas (*i.e.*, methane) from leaking through the seal and into the primary vent. The gas panel support system is significantly simplified by eliminating the need to clean the process gas. With this, during normal operations, leaks are non-existent.

The commenter (0785-John Crane Inc.) recommends that the November 2021 proposed standard be updated to include wet seal systems with these emission mitigation systems installed, as it is not practical to reduce these emissions by an additional 95 percent.

The commenter (0785-John Crane Inc.) provides that the gas seal technology initially invented by the commenter is constantly being improved to solve challenging sealing applications. Seal designs are now available that are more compact allowing the retrofit of oil sealed compressors where the transitional gas seal designs would not fit. This effectively expands the number of oil sealed compressors that are candidates for gas seal retrofits to reduce potential emissions.

Response I-23-25: The EPA appreciates the information provided by the commenter on their gas seal technology/emission mitigation system. In response to comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for centrifugal compressor affected/designated facilities in the December 2022 Supplemental Proposal, including adding requirements for dry seal compressors. For details, please see discussion in sections IV.G.1 (for NSPS OOOOb) and IV.G.2 (for EG OOOOc) of the December 2022 Supplemental Proposal.<sup>31</sup> For EPA's response to comments on the December 2022 Supplemental Proposal, see Volume II, Chapter 10 (Centrifugal Compressors) and section XI.G of the final rule preamble.

Please see section X.G.1 and X.G.2 of the preamble to the final rule which details EPA's final centrifugal compressor NSPS OOOOb and EG OOOOc standards/presumptive standards. An owner or operator would be able to employ the commenter's technology as long as the centrifugal compressor equipped with dry seals meets the requirements of the final rule.

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<sup>31</sup> 87 FR 74783-74792.

## **Chapter 14. Reciprocating Compressors**

### **14.1 General Support/Opposition for Proposed Reciprocating Compressor Requirements**

Comment: Commenters (0787/1289-Atmos Energy Corporation (Atmos), 0844-Environmental Defense Fund (EDF) *et al.*, 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD), 0605-Muscogee (Creek) Nation, 0781-National Tribal Air Association (NTAA), 0391-Keweenaw Bay Indian Community (KBIC)) support the November 2021 proposed requirement to strengthen the standards for methane emissions for new reciprocating compressors and including those requirements as the presumptive standards for existing sources.

Commenters (0787/1289-Atmos) generally support using operating hour or methane emissions rate thresholds for triggering compressor rod packing maintenance.

Response I-14-1: Comments are supportive comments on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

### **14.2 Applicability/Exemptions**

#### ***14.2.1 Applicability of Compressor Standards to Well Sites/Centralized Production Facilities***

Comment: Commenter (0808-American Petroleum Institute (API)) requests that EPA clarify the applicability of compressor standards to well sites. The commenter states that the definition proposed for central production facility may extend applicability to compressors located at well sites, which have historically been exempt from the compressor standards. As EPA states they have not updated their cost analyses with new information with respect to well sites, the commenters believe that extending applicability to well sites was not EPA's intent.

Commenter (0923-Lambda Energy Resources LLC (Lambda)) urges EPA to keep the current compressor exemptions shown in both subparts NSPS OOOO and OOOOa stating compressors "located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility."

Commenter (0564-Arkansas Independent Producers and Royalty Owners (AIPRO)) suggests maintaining the existing definition of "compressor station" listed in NSPS OOOOa (compressors located at a well site are exempt from reciprocating compressor requirements).

Response I-14-2: The applicability of compressor standards to centralized production facilities does not extend to single well sites. See section XI.G.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

Comment: Commenters (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK), 0814-Independent Petroleum Association of America (IPAA) *et al.*) note that EPA states it will apply the November 2021 proposed monitoring requirement to reciprocating compressors

located at “centralized production facilities.” The commenters state that this may be beneficial in certain operations and where larger oil and gas operators may have the resources and equipment to monitor those emissions; however, they suggest that it should be an option/alternative, and not a mandatory requirement as it may unnecessarily create additional burdens and costs for smaller operators that send production from several marginal/low production wells to a “centralized production facility.” For marginal/low production well operators, centralized production facilities may be more cost efficient than having equipment at each well site and this practice reduces the overall the environmental footprint of the operation. The commenters suggest that it would be an unnecessary additional cost on small businesses and disincentivizes the use of centralized production facilities in this scenario. The commenters request the EPA remove this requirement for marginal/low production wells that send production to centralized production facilities.

Another commenter (0844-EDF *et al.*) supports the EPA’s November 2021 proposed definition of a centralized production facility and supports the extension of compressor standards to these sites. While the Greenhouse Gas Inventory (GHGI) does not contain data on the number of compressors in the production segment, the commenter reports that they analyzed data submitted in response to the EPA’s 2016 Information Collection Request (ICR) to assess the number of compressors across different facility types in the production segment. While the ICR data is not a full inventory, the commenter contends that it illustrates that there are a significant number of compressors utilized in the production segment, with most reciprocating compressors located at centralized production facilities. [Comment letter includes a Figure (Figure 25: ICR Compressor Counts at Wellsites and Centralized Production Facilities) presenting the discussed ICR compressor counts.]

Response I-14-3: See section XI.I.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

Comment: Commenters (0465-Jordan Development Company, LLC (JDC), 0946-Michigan Oil and Gas Association (MOGA)) request that EPA listen to the small business industry segment before creating a technically and financially infeasible “one-size-fits-all” approach to regulations based on generalized production modeling and special interest groups. The commenters recommend that EPA continue the exemption of both centrifugal and reciprocating compressors “located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility” as provided in both 40 CFR part 60, subpart OOOO and 40 CFR part 60, subpart OOOOa. The commenters explain that well operators visit and service these wells and associated compressors daily to inspect for proper operation, leaks and to conduct maintenance and repairs activities. Any necessary repairs are implemented as soon as possible to avoid product loss and to maximize profit returns. If EPA wishes to propose monitoring for well site compressors, the commenters recommend EPA allow the more feasible and cost-effective monthly auditory, visual, and olfactory (AVO) inspection and documentation, similar to the requirements allowed under 40 CFR 60.5416a.

Response I-14-4: The applicability of compressor standards to centralized production facilities does not extend to single well sites. See discussion in section IV.I.1.b.iii and I.2.b of the

December 2022 Supplemental Proposal preamble regarding EPA's proposed reciprocating compressor affected facility and designated facility under NSPS OOOOb and EG OOOOc.<sup>1</sup>

With regards to comments requesting that EPA listen to the small business industry segment before creating a technically and financially infeasible "one-size-fits-all" approach to regulations based on generalized production modeling and special interest groups, see comment response to similar comments in Chapter 23, section 23.17 (One-Size Fits All Approach) of this Response to Comment Document (hereinafter referred to as the RTC), Response I-23-70.

#### ***14.2.2 Limited-Use Reciprocating Compressors***

Comment: Commenter (0808-API) requests that EPA provide clarification that temporary compressors (*i.e.*, those onsite for less than 12 months) are not subject to these provisions.

Response I-14-5: See discussion in section IV.I.1.b.i of the December 2022 Supplemental Proposal on proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year, in part, to address limited-use reciprocating compressors.

Comment: Commenter (0814-IPAA *et al.*) suggests that well pads be exempt from rod packing replacements for those compressors not used 8,760 hours per year. The commenter notes that the amount of money spent may not be cost effective in reducing emissions from these compressors.

Response I-14-6: In response to the comment that suggests that well pads be exempt from rod packing replacements for those compressors not used 8,760 hours per year, the applicability of compressor standards to centralized production facilities does not extend to single well sites. See section XI.I.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

See also the discussion in section IV.I.1.b.i of the December 2022 Supplemental Proposal on proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year, in part, to address limited-use reciprocating compressors.

Comment: Commenter (0817-GPA Midstream Association (GPA)) urges EPA to consider an appropriate exemption for reciprocating compressors with low run times. The commenter explains that, due to the nature of gathering and boosting operations, natural gas throughput is directly related to upstream producer drilling operations and a field's production volumes. Both are variable depending upon market conditions. Declines in drilling operations, and thus gas throughput, can be either permanent or cyclical in nature. This means that reciprocating compressors may not be required for extended periods of time, even for over a year. The commenter suggests that the EPA only require annual measurements for reciprocating compressors with an annual runtime above a certain threshold, such as 2190 hours over a 12-month rolling basis, or on an annual basis. The commenter notes that EPA has long recognized the role of runtime in the useful life of rod packing, as well as for other equipment. See, *e.g.*, 40 CFR part 60, subpart ZZZZ, Table 2d (requiring various maintenance activities for reciprocating internal combustion engines at 500 hours, 1,000 hours, 1,440 hours, and 2,160 hours); see also

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<sup>1</sup> 87 FR 74799-74800, December 6, 2022.

86 Fed. Reg. at 63,216 (recognizing that emission increases result from deterioration of parts with run time). According to the commenter, allowing a runtime threshold would avoid investing limited time and resources in monitoring a reciprocating compressor that has not operated, or barely operated, since the prior monitoring event, and ensure available resources are directed to the equipment that requires attention. The commenter provides that this is especially important given that upstream producers, not midstream operators, dictate how frequently reciprocating compressors run.

Response I-14-7: See discussion in section IV.I.1.b.i of the December 2022 Supplemental Proposal on proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year, in part, to address compressors with low run times.

### ***14.2.3 Applicability Thresholds Based on Reciprocating Compressor Type/Size/Stage/Gas Throughput***

Comment: Commenter (0808-API) recommends that EPA consider whether it is appropriate to establish applicability thresholds based on compressor size, stages, or gas throughput or exclude compressors used in specific applications (e.g., casing, injection, gas lift compressors).

Response I-14-8: There is insufficient information at this time to support the establishment of a standard based on compressor size, stages, or gas throughput. In situations where a reciprocating compressor is screened to have no leaks or the performance-based volumetric flow rate is maintained at or below 2 scfm, an owner or operator is only subject to minimal recordkeeping and reporting requirements.

The final requirements for reciprocating compressors under NSPS OOOOb and EG OOOOc also include several alternative compliance options to the performance-based volumetric flow rate standard that an owner or operator can comply with to meet the standards. See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenter (0831-American Exploration and Production Council (AXPC)) states that there should be an exemption for small reciprocating compressors less than 100 horsepower (i.e., vapor recovery units) that experience has shown do not exhibit rod packing leaks even without replacement. The commenter contends that there are no benefits that come from requiring replacement for these smaller units while the cost would be significant.

Response I-14-9: The EPA has not included the requested small reciprocating compressor exemption in the final rule. While the EPA is not including an exemption for small compressors that the commenter claims do not exhibit leaks even without rod packing replacement, the EPA proposed in the December 2022 Supplemental Proposal (and is maintaining in the final rule) that an owner or operator does not have to conduct volumetric flow rate monitoring if screening for emissions or leaks from the reciprocating compressor rod packing using optical gas imaging (OGI) or Method 21 does not indicate a leak. See final test methods and procedures for reciprocating compressors at 40 CFR 60.5385b and 40 CFR 60.5405c.



Comment: Commenter (0814-IPAA *et al.*) expresses that EPA fails to appreciate the variety of reciprocating compressors utilized by different segments and plays across the country. The commenter notes that most of the low volume and low-pressure wells in the Appalachian Basin are connected to a compressor to get their produced gas to a market. The commenter adds that most of these wells consist of just a wellhead which EPA rightly has proposed to exempt from NSPS OOOOb or EG OOOOc regulation. According to the commenter, the compressors used by the small companies are most commonly of two types, booster compressors, and field compressors. The booster compressors are typically small single stage units with low horsepower drivers connected to a well or groups of low-pressure wells that would not be able to deliver gas into a gathering system without help. A typical situation gathers small volumes of gas at very low pressures from groups of legacy oil wells found in many areas of the Appalachian Basin. These wellhead compressors, which were exempt under the 2016 NSPS OOOOa regulations, typically move around 10 million cubic feet per day (Mcf/d) with a suction pressure as low as 0 psi and discharge pressures of between 8 and 20 psi. The commenter recommends that, because of the pressures at which these compressors operate, they have a very small potential for fugitive emissions and should continue to be exempt from NSPS OOOOb regulation.

Response I-14-10: The applicability of compressor standards does not extend to single well sites (which are exempt from reciprocating compressor requirements under NSPS OOOOb and EG OOOOc). See discussion in section IV.I.1.b.iii and I.2.b of the December 2022 Supplemental Proposal preamble regarding EPA’s proposed reciprocating compressor affected facility/designated facility.<sup>2</sup>

See also section XI.I.5 of the final rule preamble regarding the applicability of requirements to compressors located at centralized production facilities.

### **14.3 Definitions/Clarifications**

Comment: Commenter (0817-GPA) requests that EPA define “pressurized mode.” The commenter notes that the November 2021 Proposal states that rod packing replacement would be required “[w]hen the measured leak rate exceeds two standard cubic feet per minute (scfm) (in pressurized mode)...” 86 Fed. Reg. at 63,220. The commenter states that the term “pressurized mode” is not defined. The commenter interprets “pressurized mode” to mean that the compressor contains natural gas at pressure above atmospheric pressure.

Response I-14-11: The EPA has added a definition to the final NSPS OOOOb and EG OOOOc regulatory text to clarify that “pressurized mode” is when the compressor contains natural gas that is maintained at a pressure higher than the atmospheric pressure.

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<sup>2</sup> 87 FR 74799-74800.

## 14.4 Best System of Emission Reduction (BSER) Analysis

### 14.4.1 Annual Flow Rate Measurement/Rod Packing Replacement Threshold

Comment: Commenter (0844-EDF *et al.*) suggests that EPA reduce the rod packing replacement threshold for reciprocating compressors based on annual monitoring from 2 standard cubic feet per minute (scfm) to 0.5 scfm. The commenter states that EPA has proposed requiring replacement when emissions exceed 2 scfm, which the agency estimates will achieve a 92 percent reduction in emissions for reciprocating compressors in all segments.<sup>3</sup> However, the commenter notes that, as explained in the Clean Air Task Force (CATF)'s Reciprocating Compressor Cost Memo and Spreadsheet (Attachments U and V to the commenter's letter), EPA likely overestimates the emissions reductions associated with replacement at the 2 scfm threshold, because only compressors with emissions that exceed that threshold will replace rod packing and thus reduce emissions. The commenter notes that, for compressors with emissions below that threshold, there will be no reduction in emissions. The commenter states that the 0.5 scfm threshold will reduce approximately 80 percent of compressor station emissions while remaining highly cost-effective. While EPA did not estimate the cost-effectiveness of replacement at lower thresholds, the commenter notes that the CATF estimates that imposing a 0.5 scfm threshold for rod packing replacement would entail a cost of \$270/ton of methane, not accounting for gas savings, and \$89/ton of methane after accounting for gas savings at gathering and boosting compressors, which is the highest cost segment. Figure 26 of the commenter's letter shows the cost summary for all oil and natural gas industry segments. The commenter states that these abatement costs are similar to costs for new sources as shown in EPA's November 2021 Technical Support Document (TSD) Tables 7-9 and 7-10. A detailed description of cost calculation methodology is in an attachment to their comment letter (*i.e.*, Reciprocating Compressor Cost Memo and Spreadsheet (Attachments U and V to the comment letter)). The commenter adds that a lower threshold is also in line with standards adopted in Canadian jurisdictions, which, as EPA notes, require rod packing replacement at vent volume thresholds ranging from 0.49 to 0.81 scfm/cylinder.<sup>4</sup>

Response I-14-12: The EPA received a similar comment from the commenter regarding their request for a lower performance-based volumetric flow rate standard per cylinder for reciprocating compressors on the December 2022 Supplemental Proposal. The EPA's response to this comment is provided at Volume II, Chapter 11, section 11.2.3, Response II-10-18.

See also section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenter (0817-GPA) suggests that the November 2021 proposed EG and NSPS fails to adequately consider the costs and technical challenges associated with retrofitting each cylinder for monitoring ports. The commenter notes that each throw does not have its own vent and alterations would need to be made to the piping to allow for monitoring to be conducted on a per-throw basis. The commenter states that the costs required to add new piping, so each throw

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<sup>3</sup> EPA 2021 November TSD, Spreadsheet, Chapter 7 - 2021 Compressors Costs and Emissions.

<sup>4</sup> 86 Fed. Reg. at 63,218 (citing Canadian Federal standards: <http://gazette.gc.ca/rp-pr/p2/2018/2018-04-26-x1/pdf/g2-152x1.pdf>).

has its own vent and install monitoring ports have not been considered. The commenter recommends that if EPA chooses to move forward with the November 2021 Proposal, EPA issue guidelines allowing a phased approach to adequately account for port installation.

Response I-14-13: The final rule does not require that each cylinder be equipped with a monitoring port. Individual cylinders can be manifolded to a single open-ended vent line/vent, where the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. Further, EPA proposed in the December 2022 Supplemental Proposal (and is maintaining in the final rule) that an owner or operator does not have to conduct volumetric flow rate monitoring if screening for emissions or leaks from the reciprocating compressor rod packing using OGI or Method 21 does not indicate a leak. See final standards/presumptive standards at 40 CFR 60.5386b(a) and 40 CFR 60.5405c(a) test methods and procedures for reciprocating compressors.

Comment: Commenter (0564-AIPRO) states that the November 2021 Proposal is overly burdensome and not cost effective and proposes the following alternatives to the proposed annual survey and rod packing replacement when emissions exceed 2 scfm:

- 1) Operators should be allowed to utilize optical gas imaging (OGI) leak detection and repair (LDAR) inspections on the rod packings (conducted during required or voluntary surveys) to determine if leaks are present. If a leak is identified on the rod packings – then the proposed rod packing survey would be required. If the leak rate exceeds 2 scfm – then the rod packing would need to be replaced.
- 2) Propose that the annual leak survey is required every 3 years or 26,000 hours rather than annually.

The commenter believes that either of these alternatives provide EPA with sufficient methane reductions.

Commenter (0808-API) suggests that another potential option to streamline the monitoring burden is to allow operators to screen for leaks during annual OGI assessments and only perform measurement of the rod packing if it is identified as leaking during the OGI screening. The commenter states that this option has been approved under the Greenhouse Gas reporting Program (GHGRP) for gas processing and transmission facilities under 40 CFR part 98, subpart W.

Response I-14-14: Under the December 2022 Supplemental Proposal NSPS OOOOb and EG OOOOc proposed regulatory text (and final regulatory text), an owner or operator does not have to conduct volumetric flow rate monitoring if screening for emissions or leaks from the reciprocating compressor rod packing using optical gas imaging (OGI) or Method 21 does not indicate a leak. See final standards/presumptive standards at 40 CFR 60.5386b(a) and 40 CFR 60.5405c(a) test methods and procedures for reciprocating compressors.

The EPA disagrees with the commenter that volumetric flow rate monitoring should be reduced to every 3 years or 26,000 hours of operation rather than annually or every 8,760 hours of operation. As discussed in the December 2022 Supplemental, the BSER analysis is unchanged

from what was presented in the November 2021 proposal (see 86 FR 63214–63220, section XII.E. Reciprocating Compressors). The BSER for NSPS OOOOb and EG OOOOc for reducing GHGs and VOC from reciprocating compressors is the repair or replacement of the rod packing based on annual monitoring to maintain the volumetric flow rate per cylinder below 2 scfm. As an alternative to conducting required volumetric flow rate measurements, the final rule allows an owner or operator the option to comply by replacing the rod packing on or before 8,760 hours of operation after the effective date of the final rule for NSPS OOOOb (and 8,760 hours of operation after the effective date of an approved state or tribal plan for the EG OOOOc), or on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever is later.

See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenter (0808-API) recommends that EPA re-evaluate the designated leak threshold of 2 scfm per cylinder, as it may not be appropriate for all applications. The commenter asserts that appropriate leak thresholds vary based upon the individual compressor type, size, and operating conditions. The commenter notes that their preliminary review indicates the 2 scfm/cylinder threshold proposed by EPA is an extension of regulations finalized in California.<sup>5</sup> In review of supporting documentation provided by the California Air Resources Board, the commenter notes that it seems that this threshold for rod packing replacement is based on data from a single vendor's alarm set point.<sup>6</sup> The commenter reports that publicly available data from another compressor manufacturer<sup>7,8</sup> indicates “expected packing leakage for typical alarm points is between 1.7 and 3.4 scfm,” and experience from some of the commenter's members indicates some maintenance may be conducted up to a 4 scfm threshold per manufacturer recommendations. Therefore, the commenter suggests that a more comprehensive review of compressor manufacturer information is required for determining an appropriate threshold for rod packing replacement under NSPS OOOOb and EG OOOOc.

Response I-14-15: First, the 2 scfm per cylinder performance-based volumetric flow rate standard in the final rule is not an emission limitation, but rather a performance standard associated with a work practice. Therefore, if the owner or operator obtains a measurement greater than 2 scfm, it is not a deviation of an emission limit. Rather, measures need to be taken to reduce the flow rate to 2 scfm per cylinder or less. It is not based on continuous monitoring of rod packing vents, but rather on periodic monitoring based on hours of operation. Finally, the EPA notes that the 2 scfm per cylinder performance-based volumetric flow rate standard falls within the commenter's reported “alarm point” range of 1.7 and 3.4 scfm.

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<sup>5</sup> <https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation>.

<sup>6</sup> See pages 109 -110 of the Initial Restatement of Reasoning, May 31, 2016.

<https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf>.

<sup>7</sup> <https://www.arielcorp.com/company/newsroom/compressor-emissions-reduction-technology.html>.

<sup>8</sup> [https://www.arielcorp.com/application\\_manual/Arieldb.htm#Packing\\_Leakage.htm?Highlight=packing%20leakage](https://www.arielcorp.com/application_manual/Arieldb.htm#Packing_Leakage.htm?Highlight=packing%20leakage)

The final rule also provides alternative options to meeting the final standards and presumptive standards. See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenter (0756-Baker Hughes) agrees with the November 2021 proposed method of emissions reductions however, they recommend raising the proposed leak rate of 2 scfm because frequent replacement of rod packing could lead to unnecessary blow downs. The commenter recommends tuning the leakage threshold based on the operating parameters of the compressor, mainly flow and pressures. According to the commenter, the operator should be allowed to adjust compressor performance in order to bring the leak rate down below the actionable level. The commenter also states that the detected leak rate should not require action if the packing leakage is being captured and routed for re-use or sales. The commenter suggests that continuous monitoring of compressor parameters can lead to earlier detection of unacceptable seal leakage.

Commenter (0756-Baker Hughes) also states that there are continuous monitoring methods, considering performance parameters, that can be used to predict the need for seal replacement in a timelier manner than annual seal leak monitoring and should be considered the BSER for minimizing compressor seal leakage. The commenter suggests that smart compression technology which monitors performance and other analytics of the compressor to ascertain if maintenance is required be considered where and operator can adjust performance of the compressor to optimize performance when degradation has been sensed.

Commenter (0756-Baker Hughes) adds that packing seals always leak some amount of the compressed media, even when newly installed. For larger applications, such as transmission compressors, historical data shows that newly installed packing leaks at a rate of approximately 1 scfm. The commenter states that the proposed actionable leak rate of 2 scfm will lead to a significant increase in packing replacement for large, transmission sector compressors. They explain that this in turn will lead to a significant increase in compressor blowdowns with associated large volumes of emitted blowdown methane. Before adopting such a proposal, the commenter recommends that EPA analyze the increased volume of methane emissions from more frequent blowdowns compared to increasing the actionable leak rate; especially for the larger transmission compressors.

Response I-14-16: The EPA received a similar comment from the commenter regarding their request for a higher performance-based volumetric flow rate standard per cylinder for reciprocating compressors on the December 2022 Supplemental Proposal. The EPA's response to this comment is provided at Volume II, Chapter 11, section 11.2.3, Response II-11-16.

With regards to continuous monitoring or smart compression technology, the EPA has not included the commenter's recommendation to require continuous flow rate measurements in the final rule, however, this option is available to owners and operators as an internal operational and maintenance procedure to constantly check the status of integrity of the rod packings to ensure that, when the periodic measurement is made that the flow rate is below 2 scfm per cylinder. As discussed in the December 2022 Supplemental, the BSER analysis is unchanged from what was presented in the November 2021 proposal (see 86 FR 63214–63220, section XII.E).

Reciprocating Compressors).<sup>9</sup> The BSE for NSPS OOOOb and EG OOOOc for reducing GHGs and VOC from reciprocating compressors is the repair or replacement of the rod packing based on annual monitoring to maintain the volumetric flow rate per cylinder below 2 scfm.

See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements, including provisions that allow for a delay of repair if repair would require a compressor blowdown to complete the repair.

The commenter also states that the detected leak rate should not require action if the packing leakage is being captured and routed for re-use or sales. Under the December 2022 Supplemental Proposal, the EPA proposed standards and presumptive standards that would allow owners or operators to comply by capturing and routing emissions to a process. “*Routed to a process or route to a process*” is defined to mean the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered. Owners or operators complying with this alternative option would not be required to meet the requirements of the performance-based volumetric flow rate monitoring standard.

Comment: Commenter (1291-Cumberland Valley Resources, LLC (CVR)) finds that looking for emissions from compressors of 2 scf/hr is very difficult for a small operator. To the commenter’s knowledge, there is no easy way to measure volumes as small as 2 cubic feet coming from something as complicated to isolate as the piston housing of most natural gas compressors. For what it would cost an operator to have a third party come in four times a year and measure rod packing leaks, it may be more cost effective to just go back to the NSPS OOOOa requirements of replacing the rod packing on a predetermined schedule. The commenter notes that the schedule for small compressors run at low rpm and low pressures is more cost effective for small operators at 60 months of run time than 36 months.

The commenter (1291-CVR) requests that EPA continue to allow a predetermined interval for required rod repacking instead of fugitive emission surveys but increase the time frame from 36 to 60 months and take into account actual runtime of the compressor.

Response I-14-17: The methods required to measure flow rate from reciprocating compressors are simplified versions of the demonstrated methods that are required by CFR Part 98, subpart W. The final rule only requires measurement once every 8,760 hours of operation, so the four times per year frequency mentioned by the commenter is not applicable. Also see the discussion in section IV.I.1.b of the December 2022 Supplemental Proposal,<sup>10</sup> and section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenters (0749-Petroleum Association of Wyoming (PAW), 0810-Petroleum Alliance-OK) state that the November 2021 proposed leak rate and monitoring requirements do not appear to account for variability in compressor configurations (e.g., compressor stages,

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<sup>9</sup> 87 FR 74796-74797.

<sup>10</sup> 87 FR 74797.

operating conditions, and compressor size). Each compressor would have separate leak rates. The commenters note that the vents can be monitored during OGI surveys which are currently required and may indicate when rod packing is worn and needs changed. According to the commenters, these rod packing changes are time consuming and costly. According to the commenters, the November 2021 Proposal based on 2 scfm threshold, irrespective of compressor model, may result in the need for more frequent changes especially on large units.

The commenters (0749-PAW, 0810-Petroleum Alliance-OK) add that wellsite compression will also bring in thousands of compressors to be monitored that will result in the need to have rod packing changes completed. The commenters contend that this would be burdensome as the wellsite compressors move frequently and maintaining even more records on small compressors. The commenters state that this additional burden does not seem valuable. They add that more work needs to be done to understand how rod packing vent rates would be measured, and costs for monitoring would then need to be considered.

Response I-14-18: There is insufficient information at this time to support the establishment of a standard based on compressor stages, operating conditions, and compressor size. It is anticipated that while there may be more frequent rod packing change outs for some reciprocating compressors, there will also likely be a reduction in rod packing change outs for other reciprocating compressors because of the performance-based volumetric flow rate standard. In situations where a reciprocating compressor is screened to have no leaks or the performance-based volumetric flow rate is maintained at or below 2 scfm, an owner or operator is only subject to minimal recordkeeping and reporting requirements.

The final requirements for reciprocating compressors under NSPS OOOOb and EG OOOOc also include several alternative compliance options to the performance-based volumetric flow rate standard that an owner or operator can comply with to meet the standards. See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

With regards to comments regarding wellsite compression, these compressors are not included in the definition of reciprocating compressor affected or designated facilities under NSPS OOOOb and EG OOOOc. The December 2022 Supplemental Proposal regulatory text for NSPS OOOOb and EG OOOOc defined each reciprocating compressor affected or designated facility as a single reciprocating compressor and specifies that a reciprocating compressor located at a well site is not an affected or designated facility under the standards/presumptive standards. This has been maintained in the final NSPS OOOOb and EG OOOOc.

With regards to comments that more work needs to be done to understand how rod packing vent rates would be measured, and that the costs for monitoring would then need to be considered, the December 2022 Supplemental Proposal proposed test methods and procedures for reciprocating compressors. See final standards/presumptive standards at 40 CFR 60.5386b(a) and 40 CFR 60.5405c(a) test methods and procedures for reciprocating compressors. Also note that volumetric flow rate monitoring of reciprocating compressors is also required under 40 CFR Part

98, Subpart W (subpart W) and costs considered under subpart W were used in the BSER analyses.<sup>11</sup>

See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

Comment: Commenters (0817-GPA, 1391-Interstate Natural Gas Association of America (INGAA)) agree with the proposed 2.0 scfm/cylinder leak rate threshold. The commenters acknowledge that this is the level that was adopted by the California Air Resource Board (CARB), allotting 2.0 scfm per compressor cylinder. However, the commenters express that the precise application of the proposed condition-based rod packing standard is unclear without regulatory text. One of the commenters (1391-INGAA) requests that the standard be adopted as a per cylinder standard (for example, 2 scfm/cylinder) for each reciprocating compressor unit. The commenter notes that most reciprocating compressor units have more than one cylinder, with the rod packing emissions from each individual cylinder being emitted through a vent that is common to all cylinders on the unit. The commenter explains that measurements of rod packing vent emissions for such units are typically made at the common vent, so they measure the aggregate leakage from all the cylinders that vent through the common vent. To accommodate these types of common vents, the commenter recommends that the condition-based standard allow for measurement at the common vent and the standard should have an option to be based on the total rod packing vent emissions for a unit, based on the number of cylinders, where an aggregate value would be acceptable at less than or equal to the number of operating cylinders on that compressor.

*Example:* If a Compressor had two active cylinders, each cylinder is allowed a maximum leakage rate of 2.0 scfm, an acceptable aggregate for this two-throw compressor would be 4.0 scfm. This aggregate method applies for all reciprocating compressors. These rates are more in line with the EPA's site review strategy-based tonnage thresholds of > 3.0 tons per year for initial review and < 3.0 tons for future site review. As mentioned above, the detection threshold of 10Kg/hr produces venting of 96.5 tons per year. The current the EPA guideline does not specify composite or aggregate rates.

Commenter (0817-GPA) supports the 2 scfm threshold and monitoring approach as long as EPA also provides that reciprocating compressor operators may use an average leak rate based on the number of cylinders routed to a common vent stack. The commenter explains that using an average is appropriate, as a single reciprocating compressor can have multiple cylinders (also referred to as throws), often routed to a common vent stack. In this situation, it is impractical and unreasonable to require operators to separately route each cylinder in order to gather cylinder-specific measurements. The commenter requests that EPA allow operators to use an average based on the number of cylinders routed to the common vent system. Under such a procedure, if the average leak rate exceeds 2 scfm, the operator would be required to timely identify the cylinder that failed and effect repairs, if necessary, in accordance with an appropriate delay of repair provision. The commenter states that averaging across cylinders where rod packing vents

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<sup>11</sup> Greenhouse Gas Reporting Program (EPA ICR No. 2300.18, OMB Control No. 2060-0629) to the Office of Management and Budget (OMB).



are manifolded to a common header is consistent with the California regulations on which EPA based its 2 scfm leak rate proposal. 17 CCR § 95668(c)(4)(D).

Commenter (0577-Kansas Independent Oil & Gas Association (KIOGA)) inquires whether the 2 scfm threshold for reciprocating compressors identified in Table 3 at 86 Fed. Reg. 63121 is determined on a per cylinder basis or on a per compressor basis. The commenter states that some compressors have a common vent, which would require piping modifications if required to measure the vent rate from each cylinder.

Response I-14-19: The EPA received a similar comment on the December 2022 Supplemental Proposal from commenters regarding the need for clarification that the performance-based volumetric flow rate standard for reciprocating compressors is on a per cylinder basis. The EPA's response to this comment is provided at Volume II, Chapter 11, section 11.2.3, Response II-11-7 and section XI.I.3 (Clarification that the standard is based on a per-cylinder basis) of the preamble to the final rule responds to these comments.

See also section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

#### ***14.4.2 Flow Rate Measurement Monitoring Interval***

##### ***14.4.2.1 Hours of Operation Versus Calendar Year***

Comment: Commenters (1391-INGAA, 0585-Kentucky Oil and Gas Association (KOGA), 0808-API, 0814-IPAA *et al.*, 0831-AXPC, 0820-Pioneer Natural Resources USA, Inc. (Pioneer), 0911-North Dakota Petroleum Council (NDPC)) on the November 2021 Proposal recommend that EPA consider requiring flow rate monitoring based on a compressor's hours of operation totaling one year (*i.e.*, 8,760 hours) in lieu of requiring annual flow rate measurements based on a calendar year (*i.e.*, 365 days). Commenters state that using the compressor's hours of operation would ensure that undue burden is not placed on owners and operators where compressors are not operational for multiple months or are used intermittently. The commenters explain that basing flow rate measurement requirements on a reciprocating compressor's hours of operation would allow owners and operators to stagger maintenance activity throughout the year and replacement would be based on actual use instead of potential use.

Commenter (0911-NDPC) suggests that as an alternative, EPA consider requiring reciprocating compressors be monitored every other calendar year.

Response I-14-20: See discussion in Section IV.I.1.b of the December 2022 Supplemental Proposal on proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year.<sup>12</sup>

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<sup>12</sup> 87 FR 74797.

#### 14.4.2.2 Other Comments Related to Monitoring Intervals – NSPS OOOOa Requirements

Comment: Commenters (0814-IPAA *et al.*, 0585-KOGA) state that the current NSPS OOOOa requirement of replacing rod packing of a reciprocating compressor every 36 months is also a burden to the small operator. The commenters contend that unnecessary maintenance and down time hurts revenue with no material benefit. The commenters add that rod packing in compressors that run at relatively low pressures and rod packing can last well over 60 months, and even longer if the compressor runs intermittently. The commenters recommend that EPA increase the interval for required rod repacking from 36 to 60 months and consider actual runtime of the compressor. In addition, for compressors at wellheads, the commenters suggest that EPA allow the option for OGI surveys to monitor rod packing leaks. The commenters recommend that, if a leak is found during an annual survey, the measurement can be used to determine a rate and need for replacement.

Response I-14-21: In response to the comment that the current NSPS OOOOa requirement of replacing rod packing of a reciprocating compressor every 36 months is a burden to the small operator, the EPA is not reconsidering the requirements for reciprocating compressors under NSPS OOOOa. See Chapter 7 (Compressors) of the RTC document for *EPA's Proposed Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* (2015 NSPS OOOOa Proposal) for comments on the 2015 NSPS OOOOa Proposal and EPA's responses to those comments. See also EPA's rationale for the proposed 2015 NSPS OOOOa in the preamble to proposed rule<sup>13</sup> and EPA's rationale for the final 2016 NSPS OOOOa in the preamble to the final rule.<sup>14</sup>

With regards to the requirements for reciprocating compressors at wellheads, these compressors are not considered reciprocating compressor affected or designated facilities under the NSPSs OOOOa and OOOOb and EG OOOOc. The December 2022 Supplemental Proposal regulatory text for NSPS OOOOb and EG OOOOc defined each reciprocating compressor affected or designated facility as a single reciprocating compressor and specifies that a reciprocating compressor located at a well site is not an affected or designated facility under the standards/presumptive standards. This has been maintained in the final NSPS OOOOb standards and EG OOOOc presumptive standards.

See December 2022 Supplemental Proposal preamble section IV.I.1.b for a discussion on EPA's proposal to require volumetric flow rate monitoring based on hours of operation versus calendar year. See also Response I-14-20 in section 14.4.2.1 of this RTC document on December 2022 Supplemental Proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year under the NSPS OOOOb and EG OOOOc standards and presumptive standards.

Finally, the final rule does not require that the rod packings be changed out at any specific interval. Rather, monitoring is required every 8,760 hours of operation. And this monitoring is only required if the compressor fails the initial screening. Therefore, if the rod packing integrity

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<sup>13</sup> 40 CFR 56620-56622, September 18, 2015. See Section VIII.C (Proposed Standards for Reciprocating Compressors).

<sup>14</sup> 40 CFR 35848-35849, June 3, 2016. See Section VI.B (Reciprocating Compressors).

is sound and the flow rate remains below 2 scfm, the period between rod packing changeouts could be 60 months (or even more). Further, if the monitoring results in a flow rate greater than 2 scfm per cylinder, the owner or operator is not required to change out the rod packing if other measures could reduce the flow rate below that level. In conclusion, EPA feels that the final NSPS OOOOb standards and EG OOOOc presumptive standards are less burdensome than required rod packing changeouts.

Comment: Commenter (0789-Pennsylvania Department of Environmental Protection (PDEP)) recommends that EPA clarify that the proposed requirement for reciprocating compressors is the shorter of 36 calendar months or 26,000 hours of operation.

Response I-14-22: The November 2021 Proposal performance-based volumetric standard monitoring requirements for reciprocating compressors were based on annual monitoring. See December 2022 Supplemental Proposal preamble section IV.I.1.b for a discussion on EPA's proposal to require volumetric flow rate monitoring based on hours of operation versus calendar year.<sup>15</sup> See Response I-14-20 in section 14.4.2.1 of this RTC document on the December 2022 Supplemental Proposal to require volumetric flow rate monitoring based on compressor hours of operation versus calendar year. As an alternative to conducting required volumetric flow rate measurements, the final rule allows an owner or operator the option to comply by replacing the rod packing on or before 8,760 hours of operation after the effective date of the final rule for the NSPS OOOOb (and 8,760 hours of operation after the effective date of an approved state or tribal plan for the EG OOOOc), on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever is later.

#### 14.4.2.3 Retain NSPS OOOOa Reciprocating Compressor Rod Packing Replacement Requirements

Comment: The commenters state that some company programs and states have adopted the NSPS OOOOa standard. For example, the commenters report that the EPA Methane Challenge Program includes a fixed schedule program from reciprocating compressor rod packing based on NSPS OOOOa criteria as an accepted Best Management Practice (BMP) for the program. The commenters add that EPA's website indicates that over 200 facilities voluntarily implemented reciprocating compressor reductions in 2019.<sup>16</sup> Allowing a fixed schedule option allows companies consistency with NSPS OOOOa and voluntary programs, would maintain consistency with state permit conditions or requirements, and allow flexibility for existing compressors under EG OOOOc. The commenters state that EPA has not provided data to determine that scheduled rod packing replacement is no longer an adequate method, warranting elimination of this option entirely. Commenters further add that EPA has not provided enough real-world data on one option being better, and one may be less burdensome to some operators and equipment configurations.

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<sup>15</sup> 87 FR 74797.

<sup>16</sup> U.S. EPA, Natural Gas STAR Methane Challenge Program: BMP Commitment Option Technical Document, at 14 (July 2020) [https://www.epa.gov/sites/default/files/2020-07/documents/mc\\_bmp\\_technicaldocument\\_2020-07.pdf](https://www.epa.gov/sites/default/files/2020-07/documents/mc_bmp_technicaldocument_2020-07.pdf)

Commenter (0817-GPA) notes based on information from the TSD calculation sheet, EPA assumes the rod packing will last for three to 4.4 years. Because this is the assumption used, it is reasonable to maintain the existing three-year replacement schedule as previous rulemakings have already determined it is a reasonable cost to reduce emissions. The commenters are not opposed to adding condition-based maintenance as an alternative to the prescribed maintenance schedule but recommend that both options be included with the operator selecting their preferred approach.

Commenters (0750-Flogistix, 0810-Petroleum Alliance-OK) state that they are concerned that EPA is proposing that the owner or operator of a reciprocating compressor-affected facility would now be required to monitor the rod packing emissions annually using a flow measurement. The commenters state that thousands of units would need measurement features added. In addition, they add that many operators use leased reciprocating compressors where vendors replace the rod packing as part of our 3 year/26,000-hour maintenance program. The commenters state that this schedule is preferable for ease of compliance, so they recommend EPA keep the existing requirements under NSPS OOOOa for these types of compressors.

Response I-14-23: With regards to comments that recommend retaining the current NSPS OOOOa requirements for rod packing based on a defined maintenance schedule in NSPS OOOOb and EG OOOOc, and supplement that requirement with optional use of condition-based maintenance as an alternative, the EPA maintains, as set out in sections XII.E.1.d and 2 of the November 2021 proposal preamble,<sup>17</sup> that annual rod packing flow rate monitoring and replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm represents BSER for NSPS OOOOb for all segments including reciprocating compressors located at centralized productions facilities (with the exception of compressors at stand-alone well sites).

While not including a 3-year fixed schedule for rod packing replacement in the NSPS OOOOb standards and EG OOOOc presumptive standards, as an alternative to conducting the required volumetric flow rate measurements, an owner or operator can choose to comply by replacing the rod packing on or before 8,760 hours of operation after initial startup, on or before 8,760 hours of operation after the effective date of the final rule for NSPS OOOOb (and 8,760 hours of operation after the effective date of an approved state or tribal plan for the EG OOOOc), on or before 8,760 hours of operation after the previous flow rate measurement, or on or before 8,760 hours of operation after the date of the most recent compressor rod packing replacement, whichever is later.

With regards to comment that operators often use leased compressors where vendors replace the rod packing as part of their 3 year/26,000-hour maintenance program, the vendor would need to adjust its maintenance program to meet standards. Further, if the 3 year/26,000-hour maintenance program is sufficient to maintain the compressor vent volumetric flow rate at or below 2 scfm per cylinder, more frequent rod packing replacement would not be necessary.

With regards to comments that state that thousands of units would need measurement features added, see comment response I-14-13 that clarifies that the final rule does not require that each

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<sup>17</sup> 86 FR 86 63215-63219.

cylinder be equipped with a monitoring port. The EPA recognizes, however, that equipment modifications may still be required to facilitate volumetric flow rate measurements where a company does not already conduct such measurements (*e.g.*, under a company's standard operating practices or to comply with 40 CFR Part 98, subpart W requirements).

The final requirements for reciprocating compressors under NSPS OOOOb and EG OOOOc also include other alternative compliance options to the performance-based volumetric flow rate standard that an owner or operator can comply with to meet the standards. See section X.I of the final rule preamble for a summary of the final reciprocating compressor requirements.

#### ***14.4.3 Routing Emissions to a Process Via a Closed Vent System Under Negative Pressure***

Comment: Commenter (0817-GPA) notes that routing emissions to a process should not require negative pressure, stating that some pressure differential is required to take gas out of the rod packing vent and into the desired location; whether it be a control device or routed back to the system. The commenter states that this process is already understood for flares, controls for pumps and tanks, and routing emissions to supplemental fuel do not require negative pressure. The commenter further states that the use of negative pressure can raise safety and operational issues, and that operating a crankcase collection system under negative pressure (*i.e.*, in a vacuum) creates the possibility of introducing oxygen into the system. The commenter adds that allowing for pressure differential without requiring operation under negative pressure could lead to larger emission reductions overall, and that the proposed negative pressure requirement eliminates the use of technologies that could reduce methane emissions further, for example routing rod packing to a combustor flare or SLIPSTREAM® systems to inject rod packing into the fuel system. Finally, the commenter states that without positive pressure in the closed vent system prior to the shut off valve, automatic ignition controls will not operate. The commenter suggests that where a closed vent system using positive pressure can be certified as providing effective control under maximum instantaneous flow rates without leaks, EPA permit its use.

Another commenter (0745-Step 2 Compliance, LLC (S2C)) similarly reports that the use of negative pressure presents safety concerns of creating an explosive mixture of natural gas and atmospheric air, should there be any leak between the negative pressure source and the packing vent. The commenter states that if the packing vent recovery system is at a lower pressure; the packing vent gas will be recovered without leaking to atmosphere and there will be no risk of introducing atmospheric air to the natural gas.

Commenter (0923-Lambda) states that routing compressors packings through a closed-loop system under negative pressure is infeasible at most of the commenter's compressor sites and should not be part of the final rule.

Response I-14-24: See December 2022 Supplemental Proposal preamble at section IV.I.1.b.ii for EPA's response to comments on routing emissions to a process via a closed vent system (CVS) under negative pressure.<sup>18</sup> The EPA proposed to revise (and has finalized) this compliance

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<sup>18</sup> 87 FR 74798.

alternative by continuing to allow emissions to be routed to a process via a CVS but removing the requirement for this to occur under negative pressure.

#### ***14.4.4 Repair or Replacement/Delay of Repair/Performance Adjustment***

Comment: Commenter (0817-GPA) states that repair should be allowed as an alternative to replacement; with appropriate delay of repair as an option. Repairs, without complete repacking, should be an option as well. The commenter notes that for older units, replacing the rod packing does not always address emissions, as other maintenance issues can contribute to cylinder emissions, such as issues with the rod itself. The commenter asserts that operators should have the option of either approach, so long as that option ultimately results in compliance with a two scfm standard. Providing this flexibility can significantly impact personnel costs as a rod packing replacement on older units can require approximately 32-man hours per cylinder, while a repair may entail a significantly lower level of effort. The commenter notes that a repair alternative would be consistent with the California regulations on which EPA has based the two scfm standard for reciprocal compressors, as California provides repair as an option instead of repacking. See 17 CCR § 95668(c)(3)(D).

The commenter (0817-GPA) adds that the California regulations also allow for a delay of repair, with notification to the agency. The commenter recommends that EPA also provide a practical delay of repair component in the rule. According to the commenter, rod packing repair or replacement requires the compressor to be taken out of service, which requires the compressor to be blown down. This creates emissions. Ideally, the commenter states that the rod packing repair or replacement should happen in conjunction with the next preventative maintenance activity that requires a blowdown, or within two years (whichever is earlier), to minimize the blowdown emissions.

Response I-14-25: See section IV.I.1.b of the December 2022 Supplemental Proposal preamble for a discussion on allowing for repair as an alternative to complete replacement of rod packing and EPA's response to these comments. The EPA proposed (and has finalized) that an owner or operator would be allowed to repair or replace the rod packing to maintain the volumetric flow rate at or below the 2 scfm per cylinder emission limit.

The final NSPS OOOOb and EG OOOOc rules require rod packing repair (or rod packing replacement) within 90 calendar days after the date of a volumetric flow rate emissions measurement that indicates a volumetric flow rate greater than 2 scfm. Delay of repair would be allowed if the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit. The repair in such cases must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years, whichever is earliest.

In addition, if the repair requires replacement of the compressor rod packing or a part, but the necessary replacement rod packing or part cannot be acquired and installed within the repair timelines specified due to supplies being unavailable (where previously sufficiently-stocked), a delay of repair is allowed. However, in order to qualify for a delay of repair, the required rod

packing or parts replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list due to parts unavailability.

Comment: Commenter (0756-Baker Hughes) requests that operators of compressors be allowed the capability to adjust performance of the compressor to decrease the packing leak rate. If performance of the compressor at a lower flowrate or lower pressure meets the needs of the operator, and by adjusting those performance parameters, the leak rate can be held down, this should be a viable mitigating action that allows the operator time to make repairs once seal wear leads to unacceptable performance. Further, the commenter requests that, if a packing leakage system is in place that captures all packing leakage in a closed loop that routes the leakage away for re-use or sales, then the packing leak rate should not be the trigger for abatement action as there are no emissions connected with the leak rate.

Response I-14-26: The EPA received similar comments from this commenter on the December 2022 Supplemental Proposal. EPA's response to this comment is provided at Volume II, Chapter 11, section 11.2.4 (Alternative Compliance Option), Response II-11-22.

#### ***14.4.5 Continuous Monitoring Technology***

Comment: Commenter (0450/1298-M-Squared Products and Services, Inc. (M2PS)) recommends continuous "point-of-source detection monitoring." The commenter states that in 2004 they designed the first prototype Packing Leak Detector (PLD) to address the on-going issue of measuring packing gland leakage from reciprocating compressor's packing gland vents. The PLDs are mechanical, non-invasive devices that can be easily installed on any reciprocating compressor cylinder packing vent to measure any leakage from the vent. The commenter explains that the unit was originally designed to measure wellhead gathering gas (specific gravity 0.65) but has since evolved to handle any type of specific gravity gas for single or multiple-service compressors. In 2015, the commenter notes that they were awarded several patents for the PLD. The commenter adds that this PLD technology has proven cost-effective and has been installed on land, offshore, gathering and storage compressor locations throughout the domestic U.S. The commenter provides that the average cost per compressor cylinder of \$10,000 including the PLD block, temperature and pressure transmitters, connection cables, mounting plate, wiring Conduit box and programmable logic controllers (PLC)-panel (for installation in existing on-site panel). Curtailing a leakage rate of greater than 8.0 Scfm/cylinder on a two-throw compressor (greater than 16.0 scfm) at \$3.00/Mcf, payout/return on investment (ROI) would occur in less than ten months. According to the commenter, this device requires no special, invasive installation and will work with all current and legacy compressors employed throughout the industry, making the PLD system the BSER and Best Available Current Technology (BACT).

The commenter (0450/1298-M2PS) provides significant information in their comments on the PLD system advantages and specifications and the following information supporting the need for point-of-source detection of those components. According to the commenter, they have seen operators selectively perform momentary observations, *e.g.*, OGI, on an annual or semi-annual basis for point-in-time leakage measurements. Annual or semi-annual measurements, like OGI, do not provide histological data about leak rates. Such measurements do not account for leaks that occur one hour/day/month, *etc.*, from that measurement point. New or remanufactured

equipment placed into service, is not measured for leakage until required by current EPA guidelines (current NSPS OOOOa regulations require packing change every 26,000 hours or thirty-six months). The equipment could be leaking unabated for months without being addressed. Hence, the commenter stresses the need for continuous point-of-service detection monitoring to identify and measure fugitive gas leakage. The commenter states that present EPA regulations do not account for unexpected leakage or hold the operator accountable for venting fugitive emissions.

*Example:* A new Ariel KBBV six throw compressor was put into service and both second stage cylinders were leaking at a rate of 20+ scfm each, measured via the PLD. Without the PLD, these compressor leakages could have gone unabated for several months without resolution. With the PLD, the operator was able to confirm and correct packing installation, emory cloth the piston rod to roughen the surface and adjust lubrication to reduce the packing gland leakage to < 1.0 scfm.

The commenter continues that OGI technicians may miss measuring existing leaks, or not measure them at all, because of the compressor's operating state. The commenter explains that where operators' shutdown compressors without blowing them down (*e.g.*, storage and transportation compressor sites), the packing gland seal is no longer in dynamic seal mode, and now is referred to as "static mode." In static mode, the packing gland assembly no longer has lubrication or piston rod movement. In this mode, the packing gland cannot prevent trapped pressurized gas in the piston area from leaking down the piston rod, through the packing gland and out the packing vent.

*Example:* A storage or pipeline transportation compressor may be shutdown, fully loaded. The dynamics packing gland seal is now in static mode and incapable of retaining trapped gas. OGI technicians, typically, do not measure shutdown units, thereby miss measuring fugitive emissions escaping from non-functioning seals. Based on measured effluent from existing compressors in a loaded shutdown state, leakage rates, as measured by the PLD, are typically 3-5 times more than of when the compressor is operating.

[Note: Further detailed information on the PLD system is included in Section 14.6 (Other) of this Chapter.]

Response I-14-27: The EPA has not included the commenter's recommendation to require continuous monitoring in the final rule, as we believe that the final reciprocating compressor requirements, specified in 40 CFR 60.5385b of NSPS OOOOb and 40 CFR 60.5393c of EG OOOOc, will be effective in reducing emissions in a cost-effective manner. Owners and operators are welcome to supplement the periodic requirement to screen and conduct flow rate measurements after 8,760 hours of operation with PLD monitoring.

Comment: Commenter (0785- John Crane Inc) calculates that in reference to section XI of the November 2021 Proposal where it states "reciprocating compressor proposed replacement of rod packing when an annual inspection exceeds 2 scfm has the potential to release methane to atmosphere for extended periods of time as the inspection interval is annually" – 2 scfm = 54.4 kg of methane per day, 1.6 metric tons methane per month, 48 CO<sub>2</sub>e tons per month at 86 percent



methane concentration. To reduce the potential of operation for extended periods of time with the vent flow above the alarm point, the commenter recommends continuous flow measurement be required with a high flow alarm point set at 2 scfm.

Response I-14-28: The EPA has not included the commenter's recommendation to require continuous flow rate measurements in the final rule, however, this option is available to owners and operators as an internal operational and maintenance procedure to constantly check the status of integrity of the rod packings to ensure that, when the periodic measurement is made that the flow rate at or below 2 scfm per cylinder. As discussed in the December 2022 Supplemental Proposal a, the BSER analysis is unchanged from what was presented in the November 2021 proposal (see 86 FR 63214–63220, section XII.E. Reciprocating Compressors).<sup>19</sup> The BSER for NSPS OOOOb and EG OOOOc for reducing GHGs and VOC emissions from reciprocating compressors continues to be the repair or replacement of the rod packing based on annual monitoring (not continuous monitoring) to maintain the volumetric flow rate per cylinder below 2 scfm.

## 14.5 Implementation Issues

Comment: Several commenters (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP), 0782-BHE, 0808-API) ask if the 2 scfm threshold for reciprocating compressors identified in Table 3 at 86 Fed. Reg. 63121 is determined on a per cylinder basis or on a per compressor basis. One commenter (0424-WVDEP) states that some compressors have a common vent, which would require piping modifications if required to measure the vent rate from each cylinder. Similarly, another commenter (0817-GPA) states it is common practice to manifold the rod packing vents together and requests that operators be allowed to measure flow rate from the manifold and average based upon the number of throws collected.

Response I-14-29: The EPA received similar comments on the December 2022 Supplemental Proposal regarding the basis for the proposed volumetric flow rate standards/presumptive standards (*i.e.*, per cylinder or per compressor) and the ability to measure the volumetric flow rate from the manifold line and average. EPA's response to these comments is provided at Volume II, Chapter 11, section 11.2.2, and section XI.I.3 of the final rule preamble.

The December 2022 Supplemental Proposal included proposed regulatory text for NSPS OOOOb and EG OOOOc clarifying how the volumetric flow rate monitoring standard would be applied, including when reciprocating compressor cylinders are manifolded together. Comments on the December 2022 Supplemental Proposal proposed requirements and EPA's responses to those comments can be found at Volume II, Chapter 11, section 11.3.1 of this RTC. 40 CFR 60.5386b of NSPS OOOOb and 40 CFR 60.5405c specify the final rule test methods and procedures for reciprocating compressors and centrifugal compressors.

Comment: Commenters (0808-API, 0817-GPA, 1391-INGAA) state that EPA needs to clarify the timing for required rod packing replacement and provide flexibility in measurement timing.

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<sup>19</sup> 87 FR 74796-74797, December 6, 2022.

One commenter (0817-GPA) continues that if a compressor stops operating before the rod packing measurement was conducted, and the compressor does not operate again for the rest of the year, the operator should not be out of compliance with the annual measurement standard. The commenter requests that EPA allow the annual measurement to be conducted at any point during the year (versus 12 months apart) to allow flexibility around the myriad of timing issues including maintenance coordination, measurement instrument availability, contractor availability, compressor shutdowns, and weather. The commenter states that EPA could, for example, allow operators to conduct the measurement at least twice in any three-year period.

Another commenter (0808-API) states that considerations on timing are the types of concerns that are well documented within subpart W for natural gas plants and transmission compressor stations. For example, the commenter provides that the requirements in 40 CFR part 98, subpart W, only require rod packing measurements when a compressor is in operating mode at the time the measurement is set to occur (*i.e.*, when the measurement team arrives onsite). The commenter notes that equipment modifications may be required to facilitate measurement of rod packing vents (*e.g.*, adding an accessible port in vent piping), and adequate implementation time must be provided.

Commenter (1391-INGAA) requests clarification regarding the timing for required rod packing replacement under a condition-based standard. The commenter explains that rod packing replacement is a major maintenance activity that must be done during an equipment shutdown. The commenter states that this maintenance must be allowed to be scheduled to minimize unnecessary interruptions to operations. The commenter recommends that replacement be required at the next planned shutdown for maintenance.

Response I-14-30: See discussion in section IV.I.1.b.i of the December 2022 Supplemental Proposal preamble on EPA's proposal to require volumetric flow rate monitoring based on compressor hours of operation (8,760 hours of operation) versus a calendar year.

See discussion in section X.I of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc reciprocating compressor requirements (including repair and delay of repair requirements).

See also comment Response I-14-13 that clarifies that the final rule does not require that each cylinder be equipped with a monitoring port. The EPA recognizes, however, that equipment modifications may still be required to facilitate cylinder vent volumetric flow rate measurements. In consideration of this and other comments the final rule allows owners or operators to conduct their first volumetric flow rate measurements from their reciprocating compressor cylinder vents on or before 8,760 hours of operation after the effective date of the final rule for NSPS OOOOb (and 8,760 hours of operation after the effective date of an approved state or tribal plan for the EG OOOOc), or on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever is later.

Comment: Several commenters (0782-BHE, 0808-API, 0813-Black Hills Energy, 1375-Kinder Morgan, 1391-INGAA) request regulation clarification including that EPA clearly state in the rule that the GHGRP subpart W methods be allowed for the flow rate measurements. These

commenters also requested that EPA clearly state the proposed reciprocating compressor annual monitoring threshold and the repair and rod packing replacement requirements. Specifically, they request that EPA provide certainty regarding the schedule for repair and “delay of repair” criteria to ensure unnecessary restrictions are not placed on repair schedules, and a clear explanation of operating requirements for measurement (*i.e.*, when the unit is operating).

Response I-14-31: See section IV.I.1.b of the December 2022 Supplemental Proposal preamble for a response to these regulation clarification comments.<sup>20</sup>

Comment: Commenter (0808-API) indicates that clarification is needed on how the annual monitoring standard is applied for certain packing vent configurations and systems. For example:

- If an operator uses a continuous meter on a rod packing vent, how would compliance be demonstrated against the annual measurement?
- How will replacing the packing due to a different reason/program affect the annual monitoring window?
- When packing vents are manifolded together, is the standard determined by multiplying the leak threshold by the number of cylinders?

Response I-14-32: The December 2022 Supplemental Proposal included proposed regulatory text for NSPS OOOOb and EG OOOOc clarifying how the volumetric flow rate monitoring standard would be applied, including when rod packing vents are manifolded together. Comments on the December 2022 Supplemental Proposal proposed requirements and EPA’s responses to those comments can be found at Volume II, Chapter 11, section 11.3.1 of this RTC.

See discussion in section IV.I.1.b.i of the December 2022 Supplemental Proposal preamble on EPA’s proposal to require volumetric flow rate monitoring based on compressor hours of operation (8,760 hours of operation) versus a calendar year.

## 14.6 Other

Comment: [Note: The following is additional detail provided by one commenter (vendor) for their Packing Leak Detector (PLD) system.] Commenter (0450/1298-M2PS) indicates that the PLD now comes in mechanical and/or digital format, capable of providing point-of-source detection, twenty-four (24) hours per day, 365 days per year. They explain that the digital unit provides information to the operating company via Modbus registers, allowing them to incorporate the data into their main PLC system to establish the following:

- Historical data of packing gland leaks (for continuous reporting capability).
- Set alarms (based on amount of leakage in scfm or other imperial/metric values, accurate to the third decimal place).
- Set shutdowns (based on amount of leakage in scfm or other imperial/metric values, accurate to the third decimal place).
- Monitor temperature.

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<sup>20</sup> 87 FR 74797-74798, December 6, 2022.

- Monitor pressure.
- Develop alternate measuring parameters to fit operating companies or governing bodies guidelines.
- The PLD has been employed to measure other leak rates for distance-piece vents, large integral fuel valves, and more.
- PLD industry rating.

The commenter (0450/1298-M2PS) reports that PLD is designed to be permanently installed on compressors to meet or exceed the abrasive environment standards set by the oil & gas industries. The mechanical and digital blocks are designed to meet API-SPEC 6A. The commenter provides that digital PLD-PLC control module assembly, transmitters, cable, and conduit assemblies are designed to meet the following engineering approvals:

#### APPROVALS/CERTIFICATIONS

- CSA Class I, Division 2, Groups A, B, C, D T4
- ANSI/UL 122701 Single Seal
- ABS (American Bureau of Shipping)
- CE
- Pressure Transducers designed for 50 up to 30,000 PSI, operating temperature -40 to 125°C
- Temperature Transducers designed for -14.504 up to 1,451 PSI, operating temperature -50 to 250°C
- IP65/IP67
- UL NRAQ.E214119 Programmable Controllers, Communication and I/O modules
- EU Declaration of Conformity:
  - Low Voltage Directive (LVD): 2006/95/EC, 2014/35/EU, EN 61131-2:2007
  - EMC Directive: 2004/108/EC, 2014/30/EU, EN 61131-2:2007
  - RoHS Directive: 2011/65/EU, EN 50581:2012

*PLD Non-invasive installation:* The commenter (0450/1298-M2PS) notes that the PLD is typically installed as close to the operating cylinder packing gland vent as possible. Some compressor rental companies are employing the PLD's on a temporary basis using polyflow line and measuring each cylinders packing vent leakage, making corrections, disconnecting the PLD and moving it to the next cylinder for leakage testing (examples included in attached PowerPoint presentation). Rental compressor companies have used this method to prevent "Inks" on offshore and land locations. Currently the commenter reports that this method has been accepted by the prevailing inspecting authorities.

The commenter (0450/1298-M2PS) adds that the PLD system may incorporate the "Zero-Emission block," a clear, sealed component, allowing fugitive emissions that may leak past the internal measuring piston to remain captured and processed upstream, as an option. A Zero-Emissions block allows a clear visual sight of the mechanical measuring pin attached to the existing PLD block, capturing fugitive emissions to be processed upstream. The Zero-Emissions block is used in cases where leakage would be the expected norm, at pressures exceeding 10

pounds per square inch gauge (psig), and in locations where gas detection is employed. This will prevent gas detectors from actuating (*e.g.*, storage and transportation compressor sites with building enclosures that employ gas detection).

[Note: Commenter (0450/1298-M2PS) includes a diagram in their comment letter titled, “Anodized aluminum or stainless-steel block with pressure/temperature transmitters and Zero-Emissions block (unit above includes optional Zero Emission block, PLD mounting plate with Condulet flange box and hardware)”.]

According to the commenter (0450/1298-M2PS), the PLD system provides operators the following benefits:

- The first device/tool capable of measuring real-time “Zero-Leak” baselines, allowing operators the ability to diagnose their packing assembly, whether new or used, and correct issues to achieve a “Zero-Leak” baseline. Operators will no longer be reliant on OEM compressor manufactures for their nebulous packing gland leak values. Operators will be able to establish and document their own “Zero-Leak” baseline, from which they will be able to monitor and identify how much and which packing gland is actually venting/leaking and set limits.
- Allows operators to diagnose:
  - Over/under lubrication
  - Improper packing material
  - Incorrect packing installation
  - Piston rod hardness/smoothness
  - Piston ring wear/rod drop
- Provides real-time measured packing vent leakage (which cylinder, when, and how much)
- Provides leak rate on dynamic packing gland in static mode when compressors are shutdown loaded (without blowdown)
- Set limits for fugitive gas emissions
- Provides packing “health” data supporting proactive maintenance and servicing
- Compatible for different gas types & multiple services
- Return on investment (ROI) in less than a year
- 24-hour monitoring (dynamic or static state)

The commenter (0450/1298-M2PS) contends that the ability of the PLD to measure volumes of fugitive emissions provide operators the information necessary to design emissions capture systems. The PLD, in conjunction with a vapor recovery unit (VRU) and/or vapor recovery tank (VRT), can provide total measurement and capture capability for operating companies. They explain that these measured and captured fugitive emissions can be used as “blanket gas” in stock tanks, recompressed to be used as fuel gas for natural gas drivers for onsite compression, power generation or other rotating equipment, or to be reintroduced into the low-pressure compression streams for recompression as sales gas.

Response I-14-33: The EPA appreciates the information provided by the commenter on their PLD technology. See comment Response I-14-27 of section 14.4.5 of this Chapter for EPA's response to comment on requiring continuous monitoring.

## Chapter 15. Equipment Leaks at Natural Gas Processing Plants

### 15.1 General Support/Opposition

Comment: Commenters (0844-Environmental Defense Fund (EDF) *et al.*, 0912-Shell Oil Company (Shell), 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD), 0391-Keweenaw Bay Indian Community (KBIC), 0781-National Tribal Air Association (NTAA), 0605-Musocogee (Creek) Nation, 0808-American Petroleum Institute (API), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD)) support EPA's November 2021 Proposal to strengthen leak detection and repair (LDAR) requirements for new natural gas processing facilities and include those requirements as the presumptive standards for existing sources.

Response I-15-1: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

### 15.2 Monitoring Requirements

Comment: Commenter (0844-EDF *et al.*) specifically expresses support for the EPA's November 2021 Proposal to require bimonthly optical gas imaging (OGI) monitoring in accordance with Appendix K for all pumps, valves, and connectors located within affected process units at onshore natural gas processing plants.

Commenter (0923-Lambda Energy Resources LLC (Lambda)) urges EPA to consider a semi-annual monitoring program given the usually small number of leaks found and considerable financial costs associated with OGI surveys and record keeping. This commenter noted their natural gas processing plants currently operate under an EPA Consent Decree that requires enhanced LDAR monitoring, including quarterly EPA Method 21 monitoring. Additionally, the plants conduct annual OGI surveys for purposes of reporting greenhouse gas (GHG) emissions under 40 CFR part 98, subpart W. They state that the proposed bimonthly OGI monitoring is overly burdensome for plant operations.

Commenters (0808-API, 0932-GHGSat, Inc.) generally supports the use of Appendix K for OGI monitoring at gas processing plants. Commenter (0808-API) suggests specified changes to the proposed Appendix K (addressed under comments on Appendix K [Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks]).

Response I-15-2: EPA acknowledges the commenter's support for the use of Appendix K for OGI monitoring at onshore natural gas processing plants. See Volume I, Chapter 22 and Volume II, Chapter 22 of this Response to Comments document regarding specific responses to comment on the requirements specified in Appendix K.

Regarding the monitoring frequency for OGI monitoring, the EPA has found that bimonthly OGI monitoring is the best system of emission reduction (BSER) for equipment leaks at onshore natural gas processing plants. EPA has also finalized an alternative LDAR program that allows the owner/operator to comply with an EPA Method 21 program like that required in New Source

Performance Standards (NSPS) OOOOa. This EPA Method 21 alternative is also like the requirements that commenter (0923-Lambda) described as part of their consent decree. There was no information provided to demonstrate that semiannual OGI monitoring would reflect the BSER for equipment leaks at onshore natural gas processing plants.

Comment: Commenter (0808-API) supports retention of NSPS VVa as an alternative monitoring option, as some facilities have compliance obligations through consent decrees or permits or are subject to state or local regulations that require the use of EPA Method 21.

Commenter (0817-GPA) asserts that EPA Method 21 should be available as a primary leak detection method. To be clear, even if EPA proceeds to propose a form of Appendix K to guide use of OGI, any rule should retain EPA Method 21 as provided for in present regulations. EPA Method 21 is a reliable and familiar leak detection method that should be regarded as a primary leak detection method, not an alternative standard or one that may only be used under certain conditions. Midstream facilities, specifically natural gas processing plants, have already invested immense time and resources to initiate a EPA Method 21 program. This includes the purchase of software systems, creation of component databases, and set up of tagging for EPA Method 21 surveys. The EPA should not consider forcing these facilities who already utilize EPA Method 21 to convert their entire monitoring system to OGI surveying where there is no emissions reduction value and conversion would require significant new administrative costs.

Response I-15-3: EPA acknowledges the commenter's support for the optional EPA Method 21 LDAR program. The final NSPS OOOOb includes an EPA Method 21 alternative LDAR program for onshore natural gas processing plants at §60.5401b instead of incorporating by reference the requirements in NSPS VVa. EPA is including this alternative LDAR program within NSPS OOOOb to provide clarity on what standards apply to equipment leaks at onshore natural gas processing plants because there has been confusion regarding the applicability of some standards (*e.g.*, connector monitoring) due to a stay of those standards in NSPS VVa.

Comment: Commenter (0932-GHGSat, Inc.) states that, typically, natural gas processing plants have additional sensors and procedures that allow for a closer monitoring of the operations when compared to other oil and gas infrastructure upstream of the processing plant. According to the commenter, the current requirement of performing EPA Method 21 for gas plants or even the annual EPA Method 21 when using OGI as the existing alternative method poses an extra burden on the operators and regulators side. In practice, the commenter notes that the current methodology creates a logistics problem by potentially having multiple points of current and previously identified leaks that might be very small but still have the same burden with respect to the paperwork trail.

Response I-15-4: EPA acknowledges the comments provided by this commenter. As described in the preamble to the November 2021 Proposal, EPA has found that bimonthly OGI monitoring is the BSER for equipment leaks at onshore natural gas processing plants. EPA has also finalized an alternative LDAR program that allows the owner/operator to comply with an EPA Method 21 program similar to that required in NSPS OOOOa.



Comment: Commenter (0932-GHGSat, Inc.) supports allowing for the consideration of other LDAR programs that could incorporate other remote sensing techniques such as satellites, aircraft, and data analytics into the LDAR program for natural gas processing plants. The commenter states that the BSER calculation when incorporating remote sensing technology into the LDAR program may be favorable when factoring a longer time horizon, as more frequent monitoring for large leaks will be in place.

Response I-15-5: EPA acknowledges the commenter's support for incorporation of alternative technologies into the LDAR program at onshore natural gas processing plants. While not evaluated for purposes of this rulemaking, EPA has provisions for the request to use an alternative means of emission limitation (AMEL) for work practice standards.

### **15.3 Equipment Classification**

Comment: Commenter (0844-EDF *et al.*) notes that common classifications of equipment at natural gas processing facilities include components in volatile organic compound (VOC) service and in non-VOC service. "In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent volatile organic compound (VOC) by weight or a component "in wet gas service," which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10 percent methane) that is not also in VOC service. The commenter (0844-EDF *et al.*) supports EPA's November 2021 Proposal to eliminate the "in VOC service" distinction for purposes of LDAR inspections and instead require bimonthly OGI at all pumps, valves, and connectors located within affected process units at processing plants. The commenter notes that EPA is correct that "a VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies." The commenter adds that they also believe that EPA is correct that "since there would be no threshold for requiring LDAR for methane, any equipment not in VOC service would still be required to conduct LDAR for methane even if not for VOC." Accordingly, they state that it is appropriate to eliminate the VOC threshold for the purposes of this LDAR program.

Commenter (0808-API) requests that the EPA not remove the VOC concentration threshold from the proposed LDAR requirements and should instead propose a similar concentration threshold for methane. The commenter recommends that EPA retain the current 10.0 percent by weight threshold for VOC and add a 1.0 percent by weight threshold for methane. They explain that while EPA is correct that a VOC concentration threshold is not an appropriate threshold for determining whether LDAR for methane applies, EPA failed to realize that some streams at a gas processing plant have de minimis concentrations of VOC and methane (*e.g.*, purity ethane, produced water, wastewater). According to the commenter, without appropriate concentration thresholds, equipment with no appreciable amounts of VOC or methane would be subject to LDAR requirements, which they do not believe was EPA's intent with the November 2021 Proposal. The commenter adds that minimum concentration thresholds are especially important if an owner or operator chooses to use EPA Method 21 since tagging of components is required (along with accounting for and maintaining these tags); and monitoring additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with little environmental benefit.

Commenter (0817-GPA Midstream Association (GPA)) suggests that EPA should retain “in VOC Service” and the VOC threshold and add an analogous methane threshold at natural gas processing plants. The commenter opposes the November 2021 Proposal to remove the “in VOC service” requirement and the 10 percent VOC by weight threshold. Further, the commenter believes that EPA should establish a similar threshold for equipment in methane service, such as a 10 percent methane threshold. Such thresholds are important because without them, operators would be wasting time and resources monitoring equipment in air, water, or steam service which have no potential to leak regulated pollutants.

Commenter (0817-GPA) believes the 10 percent VOC threshold is a valuable tool to ensure that the LDAR program is cost effective. Neither EPA Method 21 nor OGI cameras are likely to be able to detect leaks on process streams with less than 10 percent VOC, *i.e.*, those with greater than 90 percent inert materials. Monitoring components with process fluids below 10 percent VOC by weight would add a significant burden with no demonstrated benefit, even assuming that leaks could be detected. The low VOC content makes it much less likely that any components would exceed leak thresholds triggering repair obligations, but operators would spend significant resources unnecessarily monitoring these components. The commenter estimates that monitoring components in contact with streams containing less than 10 percent VOC could increase monitoring time by as much as 30 percent. Each of these arguments warrant establishing a threshold for methane as well. Both thresholds would avoid the expenditure of significant time and resources without any expectation of reducing emissions.

Commenter (0817-GPA) states that EPA justifies the elimination by stating that the “VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies.” Respectfully, that misses the point, which is that the VOC concentration threshold serves as a tool to focus on monitoring equipment where leaks may occur at levels that can be detected. Hence, EPA’s argument only means that it should establish a comparable threshold for methane as well, such as 10 percent by weight, instead of eliminating the existing VOC threshold. Without any threshold for either pollutant, operators would be required to monitor numerous components with little or no chance for emissions. This prevents any ability for an operator to eliminate monitoring based on knowledge that components are not in VOC or methane service.

Response I-15-6: See discussion in section. IV.L.1.b of the December 2022 Supplemental Proposal.<sup>1</sup>

## **15.4 Overlapping NSPS Applicability**

Comment: Commenters (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP), 0577-Kansas Independent Oil & Gas Association (KIOGA)) request applicability clarifications for existing designated facilities. Specifically, the commenters inquire whether designated existing facilities under emission guidelines (EG) OOOOc will continue to be subject to NSPS KKK. The commenters request that the EPA clarify whether both the NSPS KKK VOC standards and the EG OOOOc presumptively approvable

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<sup>1</sup> 87 FR 74808.

methane standards will apply to these facilities, or if the NSPS KKK standards will no longer apply, and these sources will be regulated by the state under EG OOOOc. The commenters also request that, if the sources will be subject to regulation under both subparts, that EPA review these subparts to ensure that the sources will not be subject to conflicting requirements and that the requirements are streamlined.

Response I-15-7: Onshore natural gas processing plants subject to NSPS KKK would continue to comply with those VOC standards until a state or federal plan implementing EG OOOOc becomes effective. After that time, compliance with the implementing state or federal plan that is consistent with the presumptive standards in EG OOOOc would constitute compliance with the equipment leak requirements in NSPS KKK because the presumptive standards result in the same or greater emission reductions than NSPS KKK, except as noted here.

For wet seal centrifugal compressors currently subject to NSPS KKK, compliance with NSPS KKK would allow for compliance with the state or Federal plan implementing EG OOOOc because the zero emissions limit would also achieve the 3 scfm limit included in EG OOOOc. Because the NSPS KKK standard is more stringent for wet seal centrifugal compressors, NSPS KKK would continue to apply.

## **15.5 Request for an Exemptions**

Comment: Commenter (0923-Lambda) request that EPA consider an exemption of natural gas processing plants that are designed to process 10 million standard cubic feet per day or less. The commenter explains that the idea of exempting small plants is the same rationale that they ask for marginal wells. They note that surveillance of the entire plant is completed via audio, visual, olfactory (AVO) methods once or more daily. They add that if any leaks are found they are fixed as soon as possible since loss of product equals loss of revenue.

Response I-15-8: EPA has included specific exceptions to the requirements for process unit equipment affected facilities at §60.5402b of NSPS OOOOb and §60.5402c of the model rule in EG OOOOc. Specifically, §60.5402b(b)(1) allows for quarterly OGI monitoring (instead of bimonthly OGI monitoring) of pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas. Further, §60.5402b(b)(2) exempts this same equipment from routine monitoring if complying with the EPA Method 21 alternative standards of §60.5401b. There is an historical basis for reduced monitoring requirements at these facilities, as they are exempt from certain monitoring requirements at §60.5401a(d) of NSPS OOOOa. See Response II-12-21 in Volume 2, Chapter 12 of this Response to Comment Document.

Comment: Commenter (0911-North Dakota Petroleum Council (NDPC)) requests that temporary portable natural gas liquid processing skids in the natural gas production sector be exempt from requirements applicable to natural gas processing plants in the natural gas processing sector.

Response I-15-9: The term “natural gas processing plant” is defined in the final rule as follows:

*Natural gas processing plant (gas plant)* means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

It is not clear from the comment if this definition is insufficient to address the commenter’s concerns about temporary portable natural gas liquid processing skids. Therefore, EPA has not made any additional changes to the definition. For additional information on the exclusion of Joule-Thompson skids from the definition of a natural gas processing plant, see Response to Public Comments on NSPS OOOO located at Document ID EPA-HQ-OAR-2010-0505-4546.

## **15.6 Closed Vent Systems and Equipment Designated as Having No Detectable Emissions**

Comment: Commenter (0844-EDF *et al.*) requests that the EPA extend bimonthly OGI monitoring to any equipment or components designated as having no detectable emissions. The commenter explains that, as bimonthly monitoring will already be required, surveying additional components and equipment will add very little cost. According to the commenter, this is an inexpensive solution for ensuring compliance that will also help operators detect any anomalous sources at the processing plant.

Commenter (0808-API) suggests that the proposed bimonthly OGI monitoring requirements should also apply to closed vent systems and equipment designated with no detectable emissions. The commenter suggests that this equipment should be treated like other fugitive emission components similar to the requirements option for quarterly EPA Method 21 monitoring of pressure relief devices in NSPS OOOO and NSPS OOOOa (40 CFR 60.401a5401(b)). According to the commenter, the increased frequency of bimonthly OGI monitoring compared to an annual EPA Method 21 survey should allow OGI to be as effective as EPA Method 21 at detecting leaks from this equipment. The commenter adds that bimonthly OGI monitoring would also decrease costs since a separate EPA Method 21 program would not be required.

Commenter (0817-GPA) requests that the EPA exclude no detectable emission components and closed vent systems from OGI monitoring requirements at natural gas processing plants. The commenter states that they support EPA’s November 2021 Proposal to retain the NSPS OOOOa requirements for closed vent systems and equipment designated as having no detectable emissions (NDE components). 86 FR 63182 (November 15, 2021). The commenter notes that EPA has, however, requested comment “on whether bimonthly OGI monitoring according to the proposed Appendix K is appropriate to demonstrate compliance with this requirement.” *Id.* The commenter states that, as noted in the November 2021 Proposal, EPA previously determined that OGI was not appropriate for monitoring closed vent systems and NDE equipment because it does not identify very small leaks and is incapable of identifying whether ““non-leaking/leakless equipment are truly nonleaking because the detection sensitivity of the optical gas imaging instrument is not sufficient.”” *Id.* (quoting 73 FR 78204 (December 22, 2008)). The commenter expresses that they are not aware of any advances in OGI technology that would allow it to

identify low-level leaks or NDE components. The commenter concludes that the current means of demonstrating compliance has worked well for many years and they believe that it should continue in that role.

Response I-15-10: See discussion in section IV.L.1.b of the December 2022 Supplemental Proposal.<sup>2</sup>

## 15.7 Leak Repair Timeline

Comment: Commenter (0844-EDF *et al.*) supports the proposed repair timeframe that would require leaks detected by OGI to be repaired within 5 days of detection, and final repairs completed no later than 15 days of detection.

Commenter (0923-Lambda) urges EPA to consider delay of repair (DOR) leniency in the event GHG components are found leaking and cannot be repaired or replaced without a process unit shutdown.

Response I-15-11: Due to the nature of OGI monitoring (i.e., surveying from a distance), the proper equipment needed for physically reaching a component may not be in place at the time of monitoring and may take longer than 5 days to put in place. The final NSPS OOOOb requires final repair completed no later than 15 days of detection. Further, the final NSPS OOOOb allows for the delay of repair for equipment that cannot be repaired or replaced without a process unit shutdown. These repair requirements apply regardless of the monitoring technique (OGI or EPA Method 21) used to detect the leak.

## 15.8 Initial Compliance Timeline

Comment: Commenter (0740-Utah Petroleum Association (UPA)) provides one small example of where the labor shortage will affect a Utah operator's ability to meet the myriad of new requirements. One Utah operator estimates the new requirements will triple the required number of leak detection and repair workers. Considering the labor shortage vis-à-vis the time needed to develop and implement new procedures, the commenter supports EPA's proposed 180 days to come into compliance with methane standards for the equipment leaks at onshore natural gas processing plants. However, the commenter also recommends that the initial compliance period for leak detection on any equipment in operation prior to the promulgating this final rule be extended to 365 days to address the planning needed and challenges resulting from the labor shortage.

Similarly, commenter (0755-Texas Pipeline Association (TPA)) supports the extension of the 180-day initial compliance deadline regarding methane standards for leaks at processing plants. In rule amendments made in 2020, EPA clarified that the initial compliance deadline for VOC equipment leak standards at natural gas processing plants was 180 days. This was a beneficial clarification for two reasons: first, it brought the NSPS OOOOa in line with existing requirements in NSPS KKK, and second, it gave owners and operators a reasonable and

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<sup>2</sup> 87 FR 74807.

workable period within which to bring affected equipment into proper operation and to conduct a thorough and accurate check on whether the equipment is in conformance with applicable leak standards.

Response I-15-12: EPA acknowledges the commenters' support for the proposed extension of the initial compliance deadline for the methane leaks at processing plants. These comments are supportive comments on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

With regards to the comment recommending that the initial compliance period for leak detection on any equipment in operation prior to the promulgating this final rule be extended to 365 days to address the planning needed and challenges resulting from the labor shortage; the EPA has not granted this request.

See Volume II, Chapter 20 (Impacts of the Proposed Rule), Response II-20-33, for EPA's response to similar concerns regarding labor availability.

## 15.9 Leaking Valve Replacement

Comment: Commenter (0844-EDF *et al.*) suggests that when leaking valves need to be replaced, EPA should consider requiring Low-E valves and packing be installed. In a recent Colorado rulemaking, the commenter states that Colorado found these options to be similar in cost to non-Low-E valves and packing and directed operators to consider them.<sup>3</sup> The commenter reports that some manufacturers claim their Low-E packing can reduce emissions of harmful gases by up to 95 percent versus valves with traditional packing, with minimal cost impacts.<sup>4</sup>

Response I-15-13: The commenter's understanding of the cost for low-E valves aligns with that of EPA in that they are similar to non-low-E valves. Therefore, replacing leaking valves with low-E valves would result in lower emissions with no additional burden. The final NSPS OOOOb and EG OOOOc requires replacing leaking valves with low-E valves, where feasible.

Comment: Commenter (0459-Velan, Inc.) notes regarding API 622 or 624, there are other API standards, as well as ISO standards that should be included for reference. API standards for type testing of packing and valves for fugitive emissions include the following:

- Fugitive emissions testing:
  - API 622 (Packing). Note: API 622 is referenced in API 624 and API 641.
  - API 624 (Rising stem valves)
  - API 641 (Quarter turn valves)
- Valve standards:
  - API standards 599, 600, 602, 603 and 623 require type testing to API 624 and compliance for production valves when specified.

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<sup>3</sup> See Colorado Air Pollution Control Division, Rebuttal Prehearing Statement, Proposed Revisions to Regulation Numbers 7 and 22 (Dec. 14-17, 2021), [https://drive.google.com/drive/folders/1mDU8Wc3iB\\_E4lj36R8AK\\_y8ptcU83Yao](https://drive.google.com/drive/folders/1mDU8Wc3iB_E4lj36R8AK_y8ptcU83Yao).

<sup>4</sup> Id.

- API standards 608 and 609 require type testing to API 641 and compliance for production valves when specified.
- API Standard 6D specifies that valves shall be qualified in accordance with API 624, API 641 or API 15848-1, when specified. Also, production valves shall comply with ISO 15848-2, when specified.

Commenter (0459-Velan, Inc.) continues, ISO standards for type testing and production of valves for fugitive emissions include the following:

- ISO 15848-1 – (Type testing of valves)<sup>5</sup>
- ISO 15848-2 – (Production acceptance test of valves)
- ISO TC 153 (Valves), WG 5 (Fugitive Emissions) is also in the process of developing a new standard for the type testing of stem seals for valves.

Commenter (0459-Velan, Inc.) notes these standards serve as a good basis for qualification of packing and valves for low-e service for the following reasons:

- They demonstrate low-e performance in an economically feasible manner and have, thus far, had a negligible or minor impact on the cost, price and availability of valves or valve packing.
- They are based on recognized and generally accepted good engineering practice (RAGAGEP), pursuant to CAA section 112(r).
- There are readily available products in the market that have been well accepted by stakeholders.
- They meet the requirements of fugitive emissions performance set out in various regulations.
- They are consensus standards, developed by industry stakeholders (oil & gas end users, packing and valve manufacturers, and engineering contractors) and represent a balanced and practical approach to meeting low-e requirements.
- Furthermore, the proposed statement that *“a low-e valve or valve packing product will include a manufacturer written warranty that it will not emit fugitive emissions at a concentration greater than 100 ppm within the first five years”*, states one of two alternative acceptable methods used in consent decrees to satisfy low-e requirements. The other alternative method is typically stated as follows:

A valve (including its specific packing assembly) that has been tested by the manufacturer or a qualified testing firm pursuant to generally-accepted good engineering practices for testing fugitive emissions and that, during the test, at no time leaked at greater than 500 ppm, and on Average, leaked at less than 100 ppm, or is an extension of another valve that qualified as “Low-E”.

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<sup>5</sup> Note: ISO 15848-1 allows the use of either methane or helium, and specifies various Tightness Classes, as well as various optional testing parameters including temperature, pressure, mechanical and thermal cycles. For reference, Tightness Classes AM (50 ppmv, methane) and BM (100 ppmv, methane) are comparable to the fugitive emissions leakage requirements specified in the API standards cited above.

Commenter (0459-Velan, Inc.) argues this alternative method of compliance to low-e requirements should be included in the wording of the proposed rule. The commenter adds in their comment a reference a list of the standards mentioned in the comments above, in particular API Standards and ISO Standards.

Commenter (0422-Private Citizen) similarly provides a list of API standards in their comment letter for type testing of packing and valves for fugitive emissions, including API Standard 622, API Standard 624 (API 600, API 602, API 603, API 623), API Standard 641 (API 599, API 608, API 609), and API 6D: Specification for Pipeline and Piping Valves. The commenter also provides information on ISO standards for type testing and production of valves for fugitive emissions. The commenter believes the standards identified outline a good basis for the qualification of Low E packing and Low E valves. The commenter provides rationale supporting this recommendation in their comment letter.

Response I-15-14: The final NSPS OOOOb and EG OOOOc requires replacing leaking valves with low-E valves, where feasible.

## 15.10 Regulatory Language

Comment: Commenter (0817-GPA) requests that EPA clarify the interaction among the different leak detection approaches when it prepares the proposed regulatory language for natural gas processing plants so that operators can properly understand the interaction between Appendix K and the existing NSPS VVa standards (40 CFR §§60.480a, *et seq.*). According to the commenter, despite the November 2021 Proposal's discussion of how NSPS VVa will be retained in large part, *see, e.g.*, 86 FR 63233 (November 15, 2021), there are aspects of NSPS VVa that are not obviously compatible with Appendix K that should be clearly retained or explained. For example:

- NSPS VVa exempts various inaccessible components, such as insulated or buried connectors, dual mechanical seal pumps, pressure relief devices with rupture disks or those routed to closed vent systems, and compressors routed to closed vent systems. The commenter notes that the November 2021 Proposal preamble was not clear on whether these components will also be exempt from OGI. The commenter believes that these components should be exempt under both standards, but the regulatory text should confirm.
- NSPS VVa requires periodic AVO inspections for pumps, compressors, closed vent systems, and other components. The commenter states that it is not clear whether, and if so why, AVO inspections would still be required under a new regulation.
- The commenter states that the November 2021 Proposal preamble did not indicate how components designated as having no detectable emissions (NDE components) will be treated. The commenter requests that the EPA clarify whether an operator may continue to designate NDE components. *See* 40 CFR §60.5401a(b)(1). In addition, the commenter requests that EPA explain the treatment of NDE components if they are found to leak.



Specifically, whether a leaking NDE component is considered a deviation or treated as another component requiring repair and re-monitoring.<sup>6</sup>

- NSPS VVa exempts various components from monitoring so long as they meet certain criteria designed to minimize emissions. *See, e.g.,* 40 CFR §60.482-2a(d) (pumps with dual mechanical seal system with barrier fluid); 40 CFR §60.482-3a(h) (compressors routed to a closed vent system); 40 CFR §60.482-4a(c) (pressure relief devices equipped with upstream rupture disk). The commenter states that the November 2021 Proposal does not indicate how these components will be treated under Appendix K. The commenter urges that they remain exempt, as EPA established these exemptions based on its judgment that it sufficiently minimized emissions and operators invested resources in equipment to ensure that these components would be exempt from monitoring. The commenter suggests that there is no reason to disrupt this status quo.
- In-situ sampling systems and sampling systems without purges are currently exempt under 40 CFR §60.482-5a. The commenter states that the November 2021 Proposal does not indicate whether they would remain exempt under Appendix K. The commenter urges that they remain exempt, as EPA has not offered any data to support a change.
- The commenter notes that Appendix K is not clear about whether there are different standards for components in heavy liquid service and light liquid service, as there are in NSPS VVa.
- The commenter states that it is not clear how Difficult to Monitor or Unsafe to Monitor components will be treated under Appendix K. The commenter notes that some components may be monitored with OGI but difficult or unsafe to repair.
- The commenter contends that the November 2021 Proposal is not clear on whether there can be alternative monitoring frequencies for process units operating for less than 365 days per year, as permitted under NSPS VVa. *See* 40 CFR §60.482-1a(f)(1).

The commenter (0817-GPA) suggests that EPA propose regulatory text that resolves these issues, that would then be subject to public comment, before it finalizes any adoption of Appendix K.

Response I-15-15: See discussion in section IV.L.1.b of the December 2022 Supplemental Proposal<sup>7</sup> and the associated proposed regulatory text for both NSPS OOOOb<sup>8</sup> and EG OOOOc.<sup>9</sup>

Comment: Commenter (0817-GPA) requests that EPA provide guidelines in proposed regulatory text for enforcement standards. As the November 2021 Proposal acknowledges, EPA Method 21 and OGI define a “leak” differently.<sup>10</sup> An OGI camera, however, cannot consistently detect leaks below approximately 10,000 ppm. The commenter thinks that EPA should clarify that, where a facility opts to perform OGI camera monitoring, any inspection by EPA enforcement personnel

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<sup>6</sup> The commenter notes that they would not oppose ending the NDE component designation. For midstream operations, they explain that there are typically few NDE components (usually pressure relief devices) that would still need to be monitored annually under the Proposed Rule. They suggest that eliminating the NDE component designation may simplify the regulations to a degree.

<sup>7</sup> 87 FR 74807.

<sup>8</sup> See Document ID No. EPA-HQ-OAR-2021-0317-1551.

<sup>9</sup> See Document ID No. EPA-HQ-OAR-2021-0317-1552.

<sup>10</sup> *See, e.g.,* 86 Fed. Reg. at 63,118, Table 2 (summarizing Method 21 leak definitions).

should also be required to use OGI camera monitoring instead of EPA Method 21. The commenter is concerned that a facility operator may properly use OGI cameras for LDAR but then be found to have violated LDAR requirements if an inspector uses EPA Method 21 to find leaking components at rates of greater than 500 ppm but less than 10,000 ppm, meaning those leaks that could not have been detected by the proper use of OGI cameras. The commenter has a similar concern where AVO inspections are required.<sup>11</sup> The EPA should clarify that an operator should not be subject to an enforcement action where it has performed the required AVO inspection, but a leak was discovered through a different leak detection method.

Response I-15-16: EPA disagrees that an operator is not subject to enforcement where EPA discovers leaks through detection methods other than the method required by the regulation. An EPA inspector's discovery of fugitive emissions, using any particular method or equipment, may or may not indicate a violation of leak detection and repair standards. But whether the evidence shows that a violation occurred is a separate question from whether certain types of evidence may be used to support an enforcement action. EPA may pursue enforcement "on the basis of any information available to the Administrator." 42 U.S.C. 7413(a), and Clean Air Act regulations make clear that EPA may use any credible evidence to establish a violation. *See* 40 C.F.R. § 60.11. That the rule identifies and allows certain leak detection equipment to be used for certain fugitive emission affected facilities, or that an owner selects a particular leak detection method or equipment, does not constrain EPA's ability to use other methods and equipment to investigate potential noncompliance or to rely on credible evidence from any method or equipment to demonstrate the existence of a violation. EPA may use any credible evidence, including evidence developed through the use of Method 21 or any other equipment or method, to establish the occurrence of a violation. Prohibiting the use of specific categories of evidence would illegally constrain EPA's enforcement authority.

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<sup>11</sup> *See* 40 C.F.R. § 5411a(c)(2) (AVO inspections for closed vent systems).

## Chapter 16. Well Completions

### 16.1 Definitions – Hydraulically Fractured/Salable Gas

Comment: Commenter (0577-KIOGA) states that, for well completions of hydraulically fractured (or refractured) gas wells as well as greenhouse gas (GHG) and VOC standards for well completions of hydraulically fractured (or refractured) oil wells, 40 CFR 60.5430a provides the following definition of *Hydraulic fracturing*:

*Hydraulic fracturing* means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions (P577).

The commenter (0577-KIOGA) believes well completions performed in Kansas, and other similar areas, do not meet EPA's definition of hydraulic fracturing for the geologic and engineering reasons provided below. The commenter recommends that the definition in NSPS OOOOa be amended to explicitly exclude conventional wells from the regulation because the work performed does not meet the definition provided in the regulation.

The commenter (0577-KIOGA) explains that operations in Kansas do utilize pressurized fluids that contain water, proppant, and/or chemicals. However, they add that the majority of the operations use a process that neither penetrates tight formations like shale or coal, nor require high rate, extended flowback, and that most Kansas operations result in little to no flowback from formations with higher quality reservoir properties than shale or coal. The commenter suggests that ignoring those two facts discounts two thirds of the definition as outlined by 40 CFR 60.5430a. According to the commenter, enforcing this regulation based on "the process of directing pressurized fluids" alone; but not based on the type of formation or subsequent flowback directly ignores the criteria outlined by the regulation.

The commenter (0577-KIOGA) states that these two criteria were included in the definition of hydraulic fracturing, as pertaining to this regulation, infers to distinguish the varying completion styles of small, vertical, conventional drilling targets from large, horizontal, tight, unconventional drilling targets (such as shale and coal).

Commenter (0577-KIOGA) assumes that this distinction was developed due to the difference in potential greenhouse gas emissions from the dissimilar formation types and completion styles. While the amount of greenhouse gases emitted from each reservoir type has yet to be quantified, the commenter assumes the greenhouse gas emissions will be proportional to the amount of hydrocarbons produced (*i.e.* the more oil and gas a well produces has the potential to produce greater amounts of greenhouse gases that well may emit). The commenter reports that the average Estimated Ultimate Recovery (EUR) for vertical wells in Kansas is 20,000-30,000 bbl/well, where shale wells yield much higher EURs. Per EIA data, the average EUR is 168,000 bbl/well for an Eagleford shale well and 243,000 bbl/well for an Eastern Bakken well. Based on these numbers, they state that a typical Kansas well will yield ~10% of the oil, and theoretically 10% of the greenhouse gas, of a typical oil shale well.

Table 7 of the commenters' (0577-KIOGA) comment letter (page 13 of the comment letter) is a comparison of typical reservoir and completion parameters for tight shale formations and for conventional formations targeted in Kansas. The commenter notes that many of the terms mentioned in the definition provided in 40 CFR 60.5430a are also included as a comparison between wells drilled in Kansas and by operators targeting tight, unconventional, shale formations.

Commenter (0577-KIOGA) explains that 99% of the oil produced in Kansas comes from sandstone and carbonate formations that have permeabilities up to six orders of magnitude times greater than that of average shale and coal formations. The commenter adds that this greater permeability in the producing formations in Kansas do not lead to high rate, extended flowback periods following well completions. According to the commenter, the average time from completion to being put on pump for production is less than 48 hours, with a majority of that time spent installing the production equipment.

The commenter (0577-KIOGA) reports that an examination of the engineering and geologic data provided in their comment letter shows that the high volume hydraulic fracture work that is completed on unconventional oil and gas wells are magnitudes greater than the hydraulic fracture work that is generally performed on conventional wells. The commenter adds that the potential for VOC and GHG emissions from an unconventional oil or gas well will proportionately be higher than conventional oil or gas wells.

The commenter (0577-KIOGA) states that the EPA states that the NSPS was intended for all oil and gas extraction, and that a well-by-well or formation-by-formation basis under the provided definition was inconsistent with EPA's express intent to address GHG and VOC emissions from all hydraulically fractured oil well completions. The commenter suggests that this is another case where EPA's attempt to develop a national regulation to cover all oil and gas operations did not consider the differences between large and small operators, or conventional and unconventional wells. The commenter offers to provide EPA with additional information upon request.

Commenter (0785-JohnCrane) recommends the following updated hydraulic fracturing definition:

...the process of directing pressurized fluids underground to exceed in-situ formation stress resulting in a permeable pathway for hydrocarbon production and consequently requiring a flowback period for return of fracturing fluids.

The commenter (0785-JohnCrane) contends that a numeric threshold for "tight formations" or "high rate, extended flowback" is not appropriate because a formation can be hydraulically fractured without being "tight" and the flowback period does not have to be "extended." The commenter recommends adjustment of the hydraulic fracturing definition to exclude those specific terms and those referring to a specific formation type (*i.e.*, shale, coal, etc.). Further, the commenter states that hydraulic fracturing can be performed using a variety of fluids, including water-based fluids, as well as acids and oil-based fluids, and does not have to occur using sand (as in the case of using acid for fracturing).

Commenter (0836-DEPA) recommends that EPA consider the following details and definition of hydraulic fracturing. Hydraulic fracturing (HF) is a completion technique that has been used since the 1940's in very tight formations with less than 1.0 mili-Darcie permeability. This completion technique was designed to release the oil from the formation rock when standard completion techniques would not work. Up to and until the shale renaissance, HF was used on conventional wells in order to accomplish the standard production flow regime expected from a more permeable reservoir rock. HF does not solely account for the high production rates and pressures that the shale wells are experiencing. Horizontal drilling accounts for the extremely high yields and production volumes. Without the high yields and production volumes, horizontal drilling would not be economical and therefore not feasible. Conventional vertical wells subjected to the same HF stimulation technique would not produce the same volumes in a shale formation and for that reason, have not heretofore been considered either technically or economically feasible. The vertical HF wells nowhere produce the high volumes on any conventional formations and therefore do not have the potential to produce the high air emission rates that EPA has claimed in this proposed rule. The higher pressures come from the shale formations when horizontally drilled and even those wells decline quickly as the available reservoir pressure that has been released through the HF technique begins to deplete. Consequently, any HF well that has declined to a lower production flow rate will not produce the same level of air emissions that would be expected from a higher producing higher yield, horizontal shale well. Knowing this fact, the commenter recommends that EPA not expect or consider these lower producing wells to be a significant source of air emissions and should not subject these lower economical wells to the same regulatory requirements.

Commenter (0729-EWTC) recommends that the HF definition include a clause (included as bold underlined text below) indicating that the purpose of the stimulation activities is for production of the well and not for other well intervention activities for added clarity. The commenter proposes the following addition to the definition. "The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions **for the purpose of production, NOT intervention.**"

The commenter (0729-EWTC) does not believe that that a numeric threshold is appropriate and applicable to all hydraulic fracturing operations, particularly those that are characterized as "tight formations" or "high rate, extended flowbacks". The commenter asserts that as different reservoirs will have different operating pressures, defining hydraulic fracturing at a single flow rate that is applied uniformly to all reservoirs is an over-generalization of the differing characteristics between reservoirs and will be difficult if not impossible to achieve. Additionally, the commenter notes that flowback will depend on individual characteristics of the particular well and how it was treated along with other factors. These factors, according to the commenter, are also constantly evolving with industry practices.

Commenter (0598-Countrymark) suggests that EPA intended to narrow the applicability of hydraulic fracturing from the broad application defined on their website to a narrower focus as presented in the 2016 NSPS. The commenter notes that the narrower focus of the 2016 NSPS only covers hydraulic fracture stimulation events that are related to unconventional wells, not

conventional wells (*i.e.*, tight formations such as coal or shale, high rate and extended flowback). The commenter states that the definition on EPA's website does not distinguish between formation type or flowback characteristics. Through multiple conversations with EPA discussing the definition provided in the 2016 NSPS, the commenter states that the EPA confirmed that they used the appropriate definition.

Commenter (0598-Countrymark) continues to advocate that the conventional wells that utilize low pressure, small volumes of water and proppant, and have a short flowback period (*i.e.*, hours or minutes) were not originally intended to be covered in the 2016 NSPS. The commenter recommends that the original definition of "hydraulic fracturing" be maintained from the 2016 NSPS and that the wells that do not meet this definition be exempt from NSPS OOOOa, OOOOb, and OOOOc. They state that their recommendation is based on the much lower potential to emit from wells that do not experience the high-volume, high-pressure fracture stimulation events that are utilized for the unconventional wells.

Commenters (0598-Countrymark, 0814-IPAA et al) provide the following three definition recommendations if numeric thresholds for "tight formations" or "high rate, extended flowback" are determined by EPA to be appropriate to include in the definition of hydraulic fracturing:

1. *Flow back time*: The commenter (0598-Countrymark) proposes that any well that has a flowback period of greater than 3 days is considered to be an extended flowback. This threshold is consistent with EPA's estimate that the minimum flowback period for high volume fracture stimulation events is at least 3 days.
2. *Tight formation*: The commenter (0598-Countrymark) notes that any formation that has a permeability that is less than one thousandth of a Darcie (0.001) should be considered to be a tight formation. Where Merriam-Webster defines a Darcie as, "a unit of porous permeability in physics equal to the permeability of a medium through which the rate of flow of a fluid having one centipoise viscosity under a pressure gradient of one atmosphere per centimeter would be one cubic centimeter per second per square centimeter cross section".
3. *Volume*: The commenter (0598-Countrymark) recommends that EPA provide guidelines that greater than 100,000 pounds of proppant and/or more than 1,000,000 gallons of water is considered to be high volume used to stimulate the formation.

The commenter (0598-Countrymark) recommends that any well stimulation event that does not meet the numeric requirements provided above not be subject to the NSPS requirements as the potential to emit from wells that are below these limits is considered to be sufficiently low.

Commenter (1341-PGCC et al) contends that EPA failed to consider and/or meaningfully address several key recommendations from the Panel and the Office of Advocacy of the U.S. Small Business Administration. The commenter notes, for example, the Panel Report recommended that EPA consider the fundamental differences between conventional, low-producing wells and unconventional wells and "propose definitions with numerical standards that give meaning to the entire regulatory definition of 'hydraulic fracturing,' based on the SERs'

characterization of the distinction between geological formations and operational characteristics Panel Report, at 33. The Panel Report for the Proposal can be found in the rulemaking docket.<sup>1</sup>

Commenter (0946- Michigan Oil and Gas Association (MOGA)) recommends that EPA clarify the definition of "hydraulically fractured" well, because various oil and gas producing regions interpret the definition differently based on specific operating parameters.

Response I-16-1: The definition of "hydraulic fracturing" in §§60.5430a, 60.5430b and §60.5430c of NSPSs OOOOa, OOOOb and OOOOc is not being reconsidered or amended under this action. NSPSs OOOOa, OOOOb and EG OOOOc define hydraulic fracturing as follows:

*Hydraulic fracturing* means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

EPA notes that NSPS OOOOb does not include substantive changes in the completion requirements from those contained in NSPS OOOOa. The issues raised by the commenters have previously been considered by EPA and comments and responses on well completions and associated definitions (including the hydraulic fracturing definition) leading to the inclusion of this definition in the final 2016 NSPS subpart OOOOa rule can be found at Docket ID. EPA-HQ-OAR-2010-0505-7632, Chapter 3. Well Completions.

Comment: Commenter (0814-IPAA et al) appreciates EPA's review of standards for well completions and their understanding of completions involving conventional wells in low pressure and low permeability reservoirs as typically found in the Appalachian Basin. The commenter states that these low pressure and low permeability wells require stimulation to produce hydrocarbons at economic rates, but often can be produced economically for many decades. Because of the low pressures, the stimulations often include energized fluids, where an inert gas, such as nitrogen, is added to help bring the fluids out of the formation. In many cases, the stimulation is performed with just the inert gas. The inert gas makes green completions impossible and the typical duration of flow back very short, typically less than 48 hours. The challenge is that the flowback will not combust due to the high nitrogen content.

The commenter (0814-IPAA et al) reports that the majority of producing states and industry acknowledge the difference between "conventional" and "unconventional" wells. The commenter states that the EPA accepts the terminology but alleges that it always intended to regulate all hydraulically fractured wells.<sup>2</sup> The commenter notes that many of the Producer Associations that they represent have argued since 2011 that conventional wells have a very different

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<sup>1</sup> *Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Emission Standards for New, Reconstructed, and Modified Sources in the Oil and Natural Gas Sector*, Document ID No. EPA-HQ-OAR-2021-0317-0074 (Sept. 2021) (Panel Report).

<sup>2</sup> EPA cites various docket materials to support their assertion at footnotes 327 through 333. Most of the footnotes cite to Docket ID Item Nos. EPA-HQ-OAR-2010-0505-0445, EPA-HQ-OAR-2010-0505-05021, and EPA-HQ-OAR-2010-0505-07632. Certain representatives of the Producer Associations searched on multiple occasions for these docket materials and they were not available for review. It is difficult to evaluate the accuracy of EPA's assertions when the cited materials are not available to the general public for review.

environmental "footprint" than unconventional wells. The commenter adds that these associations and individual companies tried to have EPA promulgate a definition of a "low pressure well" that comported with industry knowledge of marginal or stripper wells. In 2015-2016 the focus changed to "low production wells." The commenter notes that, while the terminology utilized by EPA has changed over the past 10 years, the focus of the Producer Associations has been consistent and steadfast – conventional, vertically drilled wells are fundamentally different than large volume, horizontally drilled unconventional wells and one size does not fit all. According to the commenter, it is curious that in the November 2021 Proposal, EPA's definition of "hydraulic fracturing" contains certain terms or phrases that are vague and/or subjective that casts a very, very broad net. The commenter adds that, until the November 2021 Proposal, EPA has spent little effort to explain what "tight formations" and "high rate, extended flowback" means and perhaps engages in a certain amount of "back filling" to justify casting such a broad net.

Response I-16-2: See Response I-16-1 of this Chapter.

Also note, Docket ID No. EPA-HQ-OAR-2010-0505-5021 (not -05021) is the 2015 *Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR Part 60, subpart OOOOa*; and Docket ID No. EPA-HQ-OAR-2010-0505-7632 (not -07632) is the EPA's 2016 *Response to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. 40 CFR Part 60, Subpart OOOOa*.

Comment: Commenter (0539-Alaska OGCC) notes that, in Table 2 and on page 63160 of the November 2021 proposal *Federal Register* notice, "salable gas" is referenced regarding well flowback on a hydraulically fracked well, but the term does not seem to be defined. The commenter explains that on much of the North Slope there's no gas sales market, and even where there is a market that market is very limited in size and any additional gas that may be produced during a well flowback would not be able to be sent to market anyways, so large volumes of gas could be flared/vented during a well flowback and may not be subject to the requirement to reinject or find other beneficial use for gas recovered from a development well (as required in Table 2 of the *Federal Register* notice) during flowback nor the reporting requirements listed on page 63160 of the November 2021 proposal *Federal Register* notice, depending on what the definition of salable gas actually is.

Response I-16-3: The EPA included a definition of "salable quality gas" in the December 2022 Supplemental Proposal regulatory text of NSPS OOOOb and EG OOOOc. See definition of "salable quality gas" in proposed regulatory text at [regulations.gov](https://www.epa.gov/regulations). See EPA-HQ-OAR-2021-0317-1551 and EPA-HQ-OAR-2021-0317-1552.

## **16.2 Well Completions Requirements**

Comment: Commenter (0844-EDF et al) argues that it is critical that EPA strengthen its well completions requirements to achieve the emission reductions that have been promised (and assumed in emissions inventories) since the adoption of EPA's reduced emission completion (REC) requirements in 2012.



First, the commenter (0844-EDF et al) urges EPA to tighten its venting and flaring restrictions across the completion process drawing from models that have been adopted at the state level. Specifically, the commenter proposes that for both categories of wells, EPA disallow venting in all instances except when (1) emergency circumstances are present and (2) the operator can demonstrate that “flaring is technically infeasible or would pose a risk to safe operations or personnel safety and venting is a safer alternative than flaring.”<sup>3</sup> The commenter suggests that the EPA limit emergency circumstances to cases of “a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction”<sup>4</sup> and that poses a danger to human safety.

Second, the commenter (0844-EDF et al) recommends that the EPA revise the current regulatory approach to require the operator to use REC equipment that is adequate for the particular flowback situation to control emissions from the beginning of flowback, rather than retaining the current approach. The commenter states that the technical infeasibility exemption has allowed operators to engage in extended periods of venting based on the performance limitations of inadequate or inappropriate equipment, or without even attempting to deploy REC equipment. In the 2020 technical revisions, the commenter notes that the EPA recognized and addressed one way in which operators had been exploiting this loophole, but that it was insufficient to fix the overall problem.<sup>5</sup>

Specifically, the commenter (0844-EDF et al) suggests that EPA require all flowback (including what EPA now characterizes as “initial flowback”) be routed to an enclosed vapor-tight flowback vessel, as Colorado requires, or to an enclosed controlled flowback vessel, as environmental advocates and Oxy USA Inc. have proposed in New Mexico.<sup>6</sup> The commenter explains that detailed technical testimony in the New Mexico proceedings makes it clear that the purpose of deploying properly designed REC equipment is to capture and control all flowback, including the gas, from the time when flowback begins.<sup>7</sup> The commenter adds that this is technically feasible, already standard practice for some companies, and does not present safety concerns.<sup>8</sup> According to the commenter, the current regulatory approach of identifying an “initial flowback stage” during which gas “is not subject to control” creates an unjustified and

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<sup>3</sup> Wording quoted from New Mexico venting and flaring regulations, found at New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.28.8 (“In all circumstances, the operator shall flare rather than vent natural gas except when flaring is technically infeasible or would pose a risk to safe operations or personnel safety and venting is a safer alternative than flaring.”).

<sup>4</sup> Wording quoted from Colorado venting and flaring regulations, found at 2 Colo. Code Regs. 404-1 § 100 (accessible at <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245>).

<sup>5</sup> In the 2020 technical revisions, EPA clarified that the requirement to use a separator during flowback meant a separator designed to accommodate completion flowback, regardless of whether it was a production separator. This change prevented operators from continuing to decline to use a separator during flowback on the grounds that it was technically infeasible for a smaller production separator onsite to handle completion flowback rates. See 85 Fed. Reg. 57398 at 57403 (Sept. 15, 2020).

<sup>6</sup> 5 Colo. Code Regs. 1001-9 V.D.1.a.; see also Attachments X and Z.

<sup>7</sup> See Attachment AA at 4–10 of the comment letter (and supporting exhibits).

<sup>8</sup> Id.

unnecessary loophole that has been exploited in some instances to evade the overall intent to require green completions.<sup>9</sup>

The commenter (0844-EDF et al) states that from the flowback vessel or any connected REC equipment such as a separator, EPA should require the operator to route emissions to a gathering system, productive use, or reinjection, as the current regulations provide. The commenter adds that the EPA should not, however, include the existing exemption for technical feasibility. If there are in fact specific types of situations where the gas cannot be sold, put to productive use, or reinjected, the commenter suggests that the EPA should identify and define those specific situations in the regulations, rather than defaulting to an easily misused generic characterization of technical infeasibility. The commenter notes that Colorado's rules do not have similar general technical infeasibility exemptions that apply during the completion process. Colorado only allows flaring during the entire completion process with prior, written approval, or "to ensure safety or during an Upset Condition for a period not to exceed 24 cumulative hours."<sup>10</sup> If operators need to flare longer than 24 hours due to an upset, they must seek regulatory approval to continue.<sup>11</sup>

According to the commenter (0844-EDF et al), under Colorado and New Mexico rules, flaring is also permitted in pre-approved cases during pressure testing.<sup>12</sup> The commenter states that the EPA may choose to provide some kind of accommodation for pressure testing, although pressure testing without flares is possible, and the technology for this practice currently exists.<sup>13</sup> Finally, the commenter urges EPA to impose monitoring and reporting requirements for all instances of flaring during completion operations.

Response I-16-4: The EPA did not adopt the commenter's suggested changes, however, the EPA believes that the final rule NSPS OOOOb well completion standards balance the need for compliance flexibility based on differing areas/scenarios across the country. The EPA has proposed under 40 CFR 60.5375b (proposed rule text) that operators must capture emissions during the separation flowback period of each well completion, unless it is technically infeasible to do so. The owner or operator must direct captured emissions from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. The rule provision for use of captured gas for "any useful purpose" provides flexibility such as use for mobile natural gas refrigeration units or natural gas generators for onsite electricity. Under the final rule, only if these options are not technically feasible (which may include the lack of infrastructure and gathering line concerns) would captured emissions be routed to a completion combustion device. Owners or operators

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<sup>9</sup> Id. See in particular 5 Colo. Code Regs. § 1001-9 Part F (Statements of Basis, Specific Statutory Authority and Purpose), Section T: September 17–18 & 23, 2020, Oil and gas operations (Part D), "Flowback Vessels."

<sup>10</sup> 2 Colo. Code Regs. 404-1 § 903(c)(3).

<sup>11</sup> Id. at § 903(c)(3)(C).

<sup>12</sup> See 2 Colo. Code Regs. 404-1 § 903(d)(1)(B),(E) (allowing venting or flaring "during and as part of active and required maintenance and repair", and "during a Bradenhead test..."); New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(D)(4)(c),(i) (allowing venting or flaring during "repair and maintenance" and "a bradenhead test").

<sup>13</sup> See, e.g., SCHLUMBERGER, ZERO FLARING WELL TEST AND CLEANUP, <https://www.slb.com/reservoir-characterization/reservoir-testing/zero-flaring-well-test-and-cleanup>.

also have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

### **16.3 Well Completion Fugitive Emissions Monitoring**

Comment: Commenter (0944-Kuva) suggests adding an additional category for fugitive emissions monitoring which is focused on well site completions, flow back and initial operation of new well sites. The commenter notes that Colorado has established continuous monitoring rules for new well sites requiring monitoring for the initial six months of operation of new well sites. The commenter explains that there is a specific concern during well completions and initial production stages due to the large variability of expected flow rates, potential under-sizing of equipment in case a well is producing more than expected, separation equipment that is not yet fully optimized and other process related causes. The commenter states that they are offering a relocatable continuous optical gas imaging (OGI) camera that is ideally suited for such temporary monitoring. The commenter suggests that the EPA conduct a cost-benefit analysis for such a requirement and to solicit industry comment on the cost of such an approach.

Response I-16-5: The EPA has not included the suggested additional category for fugitive emissions monitoring focused on well site completions, flow back and initial operation of new well sites. While the EPA acknowledges that there is large variability of expected flow rates, and other reasons why a well site completion may be producing and emitting more than expected, the final rule standards (see Response I-16-4 of this Chapter) would address emissions occurring during a well completion and the well site fugitive monitoring requirements of 40 CFR 60.5397b (What GHG and VOC standards apply to fugitive emissions components affected facilities?) would apply to fugitive well site emissions.

### **16.4 Gas Capture Plan**

Comment: Commenter (0941-350 Silicon Valley) suggests that in order to accomplish zero routine flaring and venting they recommend that all applications for drilling a new oil or gas well (including modifications or reconstructions) be required to include an acceptable Gas Capture Plan. The commenter states that this plan would include methods of operation and equipment that would ensure that no routine flaring or routine venting would be necessary. Approval of the plan would require agreements (1) between the applicant and a pipeline company guaranteeing transport of all its captured gas to market, (2) that well completion would not occur until gathering pipelines were available to receive the gas, (3) that production would be cut back if gathering pipelines became unable to accept its gas. The commenter adds that, if all the applicant's existing wells in the basin are not connected to gathering lines, the plan would require another agreement between the applicant and a pipeline company to attach existing wells to gathering pipelines according to a specified schedule. The commenter notes that British Petroleum (BP) recently announced that it would not drill any new well in the Permian Basin unless it has guaranteed access to a pipeline.

Response I-16-6: The EPA does not believe that a gas capture plan which requires agreements between the applicant and pipeline company where the pipeline company guarantees transport of all captured gas to market and not allowing a well completion until gathering pipelines are

available is appropriate under the NSPS. NSPSs are technology-based standards for new and modified sources of air pollution. These rules include a best available control technology (BACT) for categories of stationary air pollution sources. Standards can vary within each category according to class, type, and size of source. The NSPS establishes emission limitations achievable through application of adequately-demonstrated BACT, taking into account cost, non-air quality health or environmental impacts, and energy requirements. The EPA believes that the proposed and final rule standards (see Response I-16-4) balance the need for compliance with the need for emissions mitigation during well completions, including limiting flaring unless necessary. For additional comments requesting that EPA minimize or eliminate flaring, and EPA's responses to those comments, see Volume I, Chapter , section 17.2, and Volume II, Chapter 6, section 6.2.4 of this Response to Comment document.

## **16.5 Alaska Lat/Long Information**

Comment: Commenter (0539-Alaska OGCCO) states that page 63160 of the November 2021 proposal *Federal Register* notice requires reporting of well lat/long info in NAD83, but NAD27 is the standard in Alaska.

Response I-16-7: The EPA proposed to require NAD83 for consistency with Facility Registry Service (FRS) and CEDRI reporting systems. EPA understands that NAD83 was intended to replace NAD27 and is a stronger datum that simultaneously adjusted all previous existing horizontal stations and newer GPS surveyed stations. Positions in the North American Datum are based on the different shapes of the earth and use the best technology available at the time. The technology available in 1983 was newer and more accurate than the technology available in 1927, thus making the latitude and longitude coordinates more accurate. Additionally, EPA notes that both NSPS OOOO and OOOOa require reporting latitude and longitude based on NAD83, and as such, the November 2021 proposal is consistent with other rules in this sector.

## Chapter 17. Associated Gas

### 17.1 General Support/Opposition for Proposed Venting and Flaring Standards

Comment: Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0781-National Tribal Air Association (NTAA), 0605-Muscogee (Creek) Nation, 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD)) believe that for all equipment, the presumptive requirement should be zero emissions, and combustion should only be permitted with documentation that zero emissions is not feasible, with venting only allowed in documented emergencies. The commenters support the November 2021 Proposal's requirement for new oil wells with associated gas to capture gas for sale or use on site, or route to a flare. The commenters believe productive use should be the preference and routing for combustion, which is wasteful and still emits harmful pollutants even when burned completely, should only be allowed if productive use is technically infeasible. The commenters also support the requirements for record keeping ensuring that flares are operated correctly. The commenters believe that EPA should consider standards requiring greater than 95 percent emissions reduction when associated gas cannot be put to productive use.

Commenter (0737-Clarke Valve) supports EPA's stated goal to eliminate venting of associated gas from oil wells. However, the commenter recommends that EPA consider modifying the structure or format of not allowing flaring as a potential solution, as the November 2021 Proposal advances through the next steps in the regulatory process.

Commenter (0753-Institute of Governance & Sustainable Development (IGSD) and Center for Human Rights and the Environment (CHRE)) agrees that the capture of associated gas is the best system of emission reduction (BSER) for oil wells with associated gas. The commenter urges EPA to finalize capture as the BSER for oil wells with associated gas.

Commenter (0911-North Dakota Petroleum Council (NDPC)) disagrees with EPA's assumption that since there are no New Source Performance Standards (NSPS) that regulate associated gas venting and flaring, that one is therefore needed. The commenter notes that there are many emission sources not covered under a NSPS that are regulated through New Source Review and Title V permitting, as well as state air quality and oil and gas rules. The ratio of associated gas to barrels of oil produced (gas to oil ratio or "GOR") can vary significantly from field to field, from no associated gas to thousands of cubic feet of gas per barrel. The commenter adds that GOR can also vary with time and be episodic. They explain that, today it is uncommon for associated gas to be vented under normal circumstances for safety reasons, and many state regulations prohibit the venting of natural gas (*i.e.*, those in North Dakota). There are situations where a production field may have geographic, biological, or cultural boundaries that limit or prohibit linear infrastructure like pipelines and transmission lines from being constructed. In these situations, associated gas would need to be combusted on site if present. In response to EPA's solicitation of comments on what the definition of "access to a sales line" should be, the commenter reminds EPA that in most cases, the midstream company that designs, builds, and operates the gas gathering system (sales line) and gas processing plants is not the same as the well owner and

operators, landowners, and mineral lease owners and that one entity has little control over the other.

Commenter (0830-Devon Energy) is working to reduce flaring of associated gas across each of its operating areas and supports EPA's November 2021 Proposal to reduce methane and VOC emissions by routing associated gas to a sales line if available, using it onsite as fuel or another useful purpose, or routing to a control device.

Commenter (0738-Exxon Mobil Corporation (Exxon)) supports EPA's November 2021 Proposal to address flaring of associated gas and to apply monitoring requirements to ensure flares are operating properly.

Response I-17-1: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii of the December 2022 Supplemental Proposal preamble.<sup>1</sup>

## **17.2 Flaring**

### ***17.2.1 Reduce or Ban Flaring and Route Associated Gas***

Comment: Commenters (0195-Evangelical Environmental Network (EEN), 0196-EEN, 0215-EEN) call on EPA to ban flaring except in emergency situations. Commenters (0401-Mercy Investment Services, Inc. (Mercy), 0434-Impax Asset Management, LLC (Impax), 0443-Seventh Generation Interfaith Inc. (SGI), 0455-Radio Drama Network, Inc. (RDN), 0460-Trinity Health, 0538-Change Finance, PBC (Change)) urge EPA to end the wasteful practice of routine flaring of natural gas at oil and gas facilities, in line with regulations in Colorado and New Mexico. Commenter (0918-Colorado Local Government Coalition (COLGC)) supports the ban on routine flaring of associated gas from producing wells, in accordance with NSPS OOOOb and EG OOOOc. Commenter (0941-350 Silicon Valley) states that individual states are responsible for regulating gas flaring, but as the Office of Fossil Energy in the DOE concluded in its 2019 report on flaring “states are unlikely to significantly restrict oil production to eliminate the flaring of associated gas” because they benefit from oil production taxes, state royalties and jobs in the industry.<sup>2</sup>

Commenter (0560-Legal & General Investment Management America, Inc. (LGIM America)) suggests that the rules address routine flaring of associated gas at oil wells, which is another significant source of emissions and a practice that can be eliminated in a cost-effective manner.

Commenter (0844-Environmental Defense Fund (EDF) *et al.*) notes that during the oil extraction process, a significant amount of natural gas is often produced as “associated gas” along with the oil [comment letter includes an explanation of the processes of venting and flaring of associated gas]. The commenter acknowledges that venting and flaring of emissions can cause harmful emissions, especially methane. According to estimates by the commenter and Rystad Energy, the

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<sup>1</sup> 87 FR 74779-74780.

<sup>2</sup> Office of Oil and Natural Gas, Office of Fossil Energy, “Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts,” US Department of Energy, Natural Gas Flaring and Venting Report.pdf (energy.gov) June 2019, p.53.

commenter reports that flaring releases approximately 200,000 tons of methane into the atmosphere every year in the Permian Basin alone,<sup>3</sup> of which 87 percent is due to flaring from associated gas production.<sup>4</sup> Moreover, the commenter notes that, due to a combination of high initial production of associated gas and delays in developing gathering line infrastructure or other gas capture methods, new wells tend to flare at particularly high volumes.<sup>5</sup> For example, the commenter provides that wells drilled since 2018 accounted for 60 percent of all flaring in October 2021.<sup>6</sup> Colorado<sup>7</sup> and New Mexico<sup>8</sup> have already taken action to eliminate both venting and flaring in all non-emergency conditions, and the commenter urges EPA to do the same. The commenter supports EPA's November 2021 Proposal to eliminate non-emergency venting during production but urges EPA to strengthen its approach to flaring through performance standards, to ensure that its final standards achieve significant reductions in this damaging practice. Specifically, the commenter suggests that EPA determine that the BSER for emissions from associated gas is to capture and sell, productively use, or reinject the gas. Finally, the commenter recommends that, in any case in which flaring does occur, EPA require improved flare efficacy to minimize methane and other emissions.

Response I-17-2: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>9</sup>

Comment: Commenter (0753-IGSD/CHRE) states that, while the November 2021 Proposal indicates that EPA's preferred system is to "route associated gas to a sales line," the November 2021 Proposal does not go far enough in ensuring that oil and gas operators will not flare associated gas. The November 2021 Proposal would allow for flaring when "access to a sales line is not available." The commenter suggests, because of its impact on climate, the environment, and public health, flaring is not the BSER for associated gas. The commenter states that EPA should only permit flaring for safety reasons and in emergency situations. Flaring methane and associated gases is dangerous to surrounding communities and should be avoided in all cases where alternatives are available. Health studies show that flaring can impact pregnancy term, exacerbate asthma, release carcinogens, and cause mental health and heart related conditions.<sup>10</sup> Flaring may release climate-warming gases such as carbon dioxide, methane, and black carbon to the atmosphere, and increase local terrestrial acidification.<sup>11</sup> According to the commenter, when flares are incompletely combusted or left unlit (a common occurrence),

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<sup>3</sup> EDF, Flaring Aerial Survey Results (2021), <https://www.permianmap.org/flaring-emissions/> (last accessed Oct. 27, 2021).

<sup>4</sup> See Attachment W at pg 5 of the commenter's submission.

<sup>5</sup> See Attachment W at pg 28 of the commenter's submission.

<sup>6</sup> Id.

<sup>7</sup> See Code of Colorado Regulations, Oil and Gas Conservation Commission, 2 CCR 404-1 § 903 (accessible at <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245>).

<sup>8</sup> See New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at <https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Part27-FinalRule3.25.21a.pdf>).

<sup>9</sup> 87 FR 74779-74780.

<sup>10</sup> Cushing L., Chau K., Franklin M., & Johnston J. E. (2021) Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US, ENVIRON. RES. LETT. 16:1–10, 7.

<sup>11</sup> Motte J., Alvarenga R. A. F., Thybaut J. W., & Dewulf J. (2021) Quantification of the global and regional impacts of gas flaring on human health via spatial differentiation, ENVIRON.POLLUT. 291:1–6, 2.

methane gas is vented to the atmosphere.<sup>12</sup> The commenter adds that unconventional oil and gas (UOG) drilling exacerbates the problem, as flaring emissions reported by state regulators are often underestimated,<sup>13</sup> impacting regulator's perceived risk of vulnerable communities.

The commenter (0753-IGSD/CHRE) adds that flaring exacerbates environmental injustice. Within major oil and gas regions, the commenter notes that the burden of flares falls largely on Native communities and low-income rural areas.<sup>14</sup> The commenter adds that there is evidence that flares also disproportionately impact Hispanic and Black communities.<sup>15</sup> One study found that 210,000 people living within 5km of oil and gas production are exposed to 100 or more flares nightly.<sup>16</sup> Firsthand accounts of these flares demonstrate the need to address this oil and gas activity: Nightly flares happen so frequently that affected communities call flaring "second sunrise."<sup>17</sup>

Commenter (0753-IGSD/CHRE) also encourages EPA to look to U.S. states like Colorado and New Mexico for model regulations that prohibit routine flaring. In 2020, Colorado strengthened its oil and gas regulations by banning routine venting and flaring.<sup>18</sup> In 2021, New Mexico similarly banned all routine flaring and venting.<sup>19</sup> As state regulators recognize, the commenter notes that banning routine flaring is viable and is critical to protecting the environment and public health. EPA should finalize regulations that do not allow for flaring as an option for associated gas from new and existing wells except in emergencies and for safety reasons.

Response I-17-3: The EPA has revised our supplemental proposal based on comments received. In this final rule EPA has defined the best system of emission reduction (BSER) for new sources as associated gas recovery with limited allowances for specific circumstances of temporary flaring and venting. EPA has finalized a standard for new sources that will mostly require routing of associated gas to a sales line, or an alternative that achieves equivalent emissions reductions. As explained in Sections X.F.2. and X.F.2. of the final rule preamble, the standards for new sources do include limited circumstances that could result in flaring. For the reasons explained there, EPA still finds that these are necessary to include. For all modified and some existing sources, EPA is finalizing our proposal that could allow for routine flaring, but only in limited circumstances after a demonstration that the discussed zero emissions options are technically infeasible. For the reasons explained in Sections X.F.2. and X.F.2. of the final rule preamble, EPA finds this appropriate. Lastly, in the context of existing sources, EPA's final EG OOOOc includes a subcategory for sources that produce 40 tpy methane or less of associated gas. The

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<sup>12</sup> Agerton M., Gilbert B., & Upton Jr. G. B. (2020) Working Paper: The Economics of Natural Gas Flaring in U.S. Shale: An Agenda for Research and Policy, 28.

<sup>13</sup> Cushing L., Chau K., Franklin M., & Johnston J. E. (2021) Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US, ENVIRON. RES. LETT. 16:1–10, 2.

<sup>14</sup> Cushing L., Chau K., Franklin M., & Johnston J. E. (2021) Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US, ENVIRON. RES. LETT. 16:1–10, 7.

<sup>15</sup> Johnston J. E., Chau K., Franklin M., and Cushing L., (2020) Environmental Justice Dimensions of Oil and Gas Flaring in South Texas: Disproportionate Exposure among Hispanic communities, ENVIRON.SCI. & TECH. 54: 6289– 6298, 6289.

<sup>16</sup> Cushing L., Chau K., Franklin M., & Johnston J. E. (2021) Up in smoke: characterizing the population exposed to flaring from unconventional oil and gas development in the contiguous US, ENVIRON. RES. LETT. 16:1–10, 7.

<sup>17</sup> Juhasz A. (13 Dec 2021) Halting the Gas Export Boom, Sierra Club (last visited 5 Jan 2022).

<sup>18</sup> Colorado Oil and Gas Conservation Commission Rule 903 (2021).

<sup>19</sup> New Mexico Administrative Code Title 19, Chapter 15, Part 27.



presumptive standard for the subcategory allows routine flaring without a showing of technical infeasibility because EPA's analysis conducted after reviewing comments on the supplemental proposal indicated that it is not always reasonable with respect to cost to require these sources to route their associated gas to a sales line. See Sections X.F.2. and X.F.2. of the final rule preamble for further explanation of this subcategory.

Our data and that submitted by other commenters to the proposal and supplemental proposal indicate that alternatives to routine flaring are practical, in wide use, and increasingly cost-effective. Two state jurisdictions (NM and CO) have preceded ahead of EPA to prohibit long-term routine flaring, while two more (ND and TX) have placed significant restrictions and required similar analyses prior to allowing routine flaring. Please see the TSD chapter on associated gas in the docket regarding the cost of achieving BSER.

See Volume I, Chapter 6, Response I-6-5 of this Response to Comment Document for EPA's responses to comments on environmental justice.

Comment: Commenter (0844-EDF *et al.*) points out that as the Rystad report conveys in detail, at least one or more of the best practices for gas capture and sale, productive use, or reinjection described above are broadly available to operators at a reasonable cost in every basin and at every production level.

First, the commenter (0844-EDF *et al.*) notes that the routing gas to gathering lines for sale is very broadly available to operators. As Rystad notes, this approach is proven, ubiquitous, scalable, and relatively quick to deploy.<sup>20</sup> As 95 percent of associated gas produced in the U.S. is currently not being flared, most of this captured gas is presumably being sent to sale through gathering infrastructure.<sup>21</sup> Not only is the vast majority of associated gas routed to gathering lines, but of the quantities that are flared instead, "the vast majority of flaring is from wells that are hooked up to [infrastructure]" at some point in the wells' life.<sup>22</sup> Further, Rystad's analysis shows that a relatively small number of wells are responsible for a large proportion of total flaring across each of the states.<sup>23</sup> This ranges from 3 percent of the wells contributing 83 percent of the flaring in Colorado, to 16 percent of the wells contributing 77 percent of the flaring in North Dakota, and totals 7 percent of the wells contributing 70 percent of the flaring on average.<sup>24</sup> According to the commenter, this means that in every state analyzed, the majority of wells, and likely the great majority of wells, are already capturing gas and routing it to gathering lines.

With the exception of Colorado, the commenter (0844-EDF *et al.*) states that infrastructure access (as opposed to capacity) was identified as the constraining factor for capture for 3 percent or less of the total gas volumes flared, and upcoming compliance with Colorado's routine flaring prohibition will necessarily address the issues there.<sup>25</sup> Finally, the commenter notes that, for the

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<sup>20</sup> Attachment W at pg. 43 of commenter's submission.

<sup>21</sup> Id. at 21.

<sup>22</sup> Id. at 78.

<sup>23</sup> Id. at 6.

<sup>24</sup> Id. at 27.

<sup>25</sup> Id. at 78.

very small proportion of associated gas production where infrastructure access (*i.e.*, distance from gathering infrastructure) is identified as the key constraint, other transport, on-site use, and reinjection options are available at potentially somewhat higher but still reasonable costs.<sup>26</sup>

Commenter (0844-EDF *et al.*) reports that a system of emissions reduction that is already used by most operators for the vast majority of associated gas, mostly because it has net negative costs, is the epitome of a broadly available and highly affordable solution. The commenter adds that the fact that there are instances where operators have not already found it worthwhile to capture gas only means that in some cases there will be small net costs to this pollution control system, not that sale, productive use, or reinjection of associated gas is not an available approach. The commenter contends that, while the Rystad report identifies challenges and some constraints to deploying each of these approaches, they are clearly almost never prohibitive for gas gathering. In addition, compressed natural gas (CNG) and reinjection, the two capture approaches that Rystad identifies as the next most promising options, have different, non-overlapping constraints. The commenter states that this makes them independent alternatives, and at least one if not both should be available to most of the wells where routing to gathering is temporarily unavailable (due to, *e.g.*, downstream outages) or is long-term cost-prohibitive (due to distance from infrastructure). Overall, the commenter states that the breadth of availability and the very reasonable costs of the options more than satisfy the criteria to find capture and sale, productive use, or reinjection the “best system.”

Commenter (0558-Center for Climate and Energy Solutions (C2ES)) suggests that improving the existing pipelines capacity would allow owners and operators to capture more associated gas instead of flaring it. Alternatively, the commenter notes that the gas can be compressed and trucked to a gas processing plant or another location where it can be used as a fuel in the absence of nearby pipelines. Also, the commenter adds that gas can be utilized for local power generation by converting the gas to electric power using small-scale generators (gas-to-power). The commenter adds that EPA can require project developers to define gas utilization plans prior to developing new fields. According to the commenter, while the cost associated with transport and processing infrastructure development might be high for some owners and operators, there is an opportunity for clustering flare developments to bring the overall cost down by enabling economies of scale. These flare clusters can be co-developed in a way that allow operators to share both risks and resources as they connect their associated gas to existing or new pipelines.

Response I-17-4: See response I-17-3. See also the discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>27</sup>

Comment: Commenter (0941-350 Silicon Valley) recommends that the deadline for retrofitting flares at existing facilities be no later than January 2026. The commenter suggests that, to accomplish zero routine flaring and venting, all applications for drilling a new oil or gas well (including modifications or reconstructions) be required to include an acceptable Gas Capture Plan. The commenter suggests that this plan would include methods of operation and equipment that would ensure that no routine flaring, or routine venting would be necessary. Approval of the plan would require agreements (1) between the applicant and a pipeline company guaranteeing

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<sup>26</sup> See generally Pederstad et al., *supra* note 30; Attachment W at pgs. 38-76 of commenter’s submission.

<sup>27</sup> 87 FR 74779-74780.

transport of all its captured gas to market, (2) that well completion would not occur until gathering pipelines were available to receive the gas, (3) that production would be cut back if gathering pipelines became unable to accept its gas. The commenter states that, if all the applicant's existing wells in the basin are not connected to gathering lines, the plan would require another agreement between the applicant and a pipeline company to attach existing wells to gathering pipelines according to a specified schedule. The commenter notes that BP recently announced that it would not drill any new well in the Permian Basin unless it has guaranteed access to a pipeline.

For existing wells, the commenter (0941-350 Silicon Valley) suggests that, if no gathering pipelines are available (either because none exist or because of insufficient capacity) and there are not sufficient on-site uses for the associated gas, operators be required to seek other outlets for their associated gas. According to the commenter, flaring is not an acceptable solution for removing associated gas from a well site. The commenter provides that studies have shown that compressing associated gas at the well site and trucking it to a nearby processing plant or a location where it can be added to the pipeline system can reduce flaring substantially. This CNG trucking solution, according to the commenter, can be scaled up to carry away nearly all associated gas produced<sup>28</sup>. If the associated gas has a high heavy carbon content, natural gas liquid (NGL) recovery of propane, butane, and pentane prior to compressing the gas can increase the value of the CNG, since it improves its use in engines or pipelines, and add another source of revenue.

Response I-17-5: See December 2022 Supplemental Proposal (87 FR 74779), in which the capture, compression, and transport of associated gas to a nearby processing plant, pipeline, or methane pyrolysis operation is noted, where we state that this option is provided for under the third criterion, "used for another useful purpose." See also Response I-17-3 of this Chapter.

### ***17.2.2 Flaring as a Viable Option***

Comment: Commenter (0597-Indiana Oil and Gas Association (INOGA)) suggests that the environmentalist groups who are advocating for EPA to eliminate oil and gas companies' ability to burn gas at well sites through a flare, are the same environmental groups who also oppose a new pipeline to move gas into markets. Without the ability to transport gas to market via pipeline, burning the gas through a flare is the last option available. Commenter (0598-Countrymark Energy Resources, LLC (CER)) agrees with the above statement, and reminds EPA that the Illinois Basin has been producing oil for more than 100 years, gas pipeline infrastructure was not constructed due to the lack of sufficient gas to sell into a nearby market. The commenter does not have the ability to sell the small volume of associated gas into a pipeline system to increase revenue. Eliminating the ability to flare associated gas will significantly impact their ability to produce oil for their refinery to process into high quality fuels for their customers. The commenter states that flaring operations provide a destruction rate of 90 percent to 95 percent, or greater, of VOCs and methane. This is a viable solution in controlling emissions. The commenter recommends that EPA maintain this solution for operators that are not able to sell gas.

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<sup>28</sup> Lesley Fleischman, "Putting Out the Fire: Proven Technologies to Improve Utilization of 4 Associated Gas from Tight Oil Formations", Clean Air Task Force, November 17, 2015.

Commenter (0955-Vaquero Energy, Inc. (Vaquero)) also believes that flaring is often the only option available and urges EPA to consider the hypocrisy of these environmentalist groups.

Response I-17-6: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>29</sup> In addition, EPA agrees with the commenter that the complete elimination of flaring of associated gas in all situations is not practical, for safety and other reasons. EPA therefore has designed our final rule to prohibit long term (routine) flaring for some sources, while leaving options open to other sources to manage associated gas in ways that makes flaring less frequent. See Section X.F.2. of the final rule preamble for discussion of the final standards for OOOOb as well as the final presumptive standards for OOOOc. In the context of existing sources of associated gas, EPA included a subcategory in the final emission guidelines for sources that produce 40 tpy or less of methane that allows those sources to flare routinely without a demonstration of technical infeasibility. In accordance with the final EG, existing sources that produce over 40 tpy of methane could also flare provided other options are technically infeasible. See the final notice regulatory text for model rule text in OOOOc on this point. As alluded to above, EPA's final standards also allow for flaring where circumstances are not routine and flaring is the reasonable option for interim periods such as malfunctions or interruptions in sales line service. See section 60.5377b and 60.5377c for specific regulatory language described here. EPA believes that these various allowances for flaring address the bulk of commenters concerns. The finalized standards are not an absolute prohibition on flaring. EPA further points out that the standards in OOOOb will apply to new wells, such that only those new wells will be subject to standards that do not allow routine flaring. Existing wells where the gas is already being captured and routed to a sales line could continue that practice. Upon being designated facilities under OOOOc EG, EPA does not see a problem to continue routing to a sales line. As stated in the previous paragraph, EPA's final standards allow for flaring where circumstances are not routine and flaring is the reasonable option for interim periods such as malfunctions or interruptions in sales line service.

Comment: Commenter (0793-Permian Basin Petroleum Association (PBPA)) contends that EPA and the oil and gas industry are aligned in seeking to reduce flaring. The commenter notes that EPA defines the "affected facility" as every oil well that produces associated gas<sup>30</sup> whether or not a sales line is accessible. Because EPA has not provided regulatory text, the commenter believes that the November 2021 Proposal could be interpreted as banning flaring where a sales line is accessible through requiring that all casinghead gas be routed to the sales line.

If it were that easy, the commenter (0793-PBPA) contends that EPA's November 2021 Proposal would be unobjectionable as a practical matter, but EPA's approach falls short of acknowledging the realities of active oil field settings. When a production facility is connected to a sales line, the commenter notes that flaring may still be periodically required in a number of situations: for safety reasons when there are unexpected facility or downstream malfunctions, when there are integrity issues with the sales line, when the specifications of produced gas do not meet those required by the third-party sales outlet, when produced gas exceeds the capacity of the sales line,

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<sup>29</sup> 87 FR 74779-74780.

<sup>30</sup> 86 Fed. Reg. at 63,238. EPA also seeks comment on how to define "associated gas." Id. Associated gas should be defined as the main produced gas stream from an oil well and should not be defined to include any short-term or relatively small volumes of gas produced from maintenance events involving activities like equipment blowdowns.

compressor station downtime, and processing plant downtime. In the case of a midstream operator's facility malfunction or force majeure event, it is very unlikely that the upstream operator will receive any advance notice or have any control over when the downstream facility comes back online.

According to the commenter (0793-PBPA), a ban on flaring would also significantly chill new upstream production. The commenter explains that basic laws of economics dictate that development of midstream infrastructure like sales lines will always lag upstream development: midstream operators cannot be expected to build out infrastructure to a given area until after establishment of significant upstream production in that area. And chilling domestic production will do nothing to address consumer demand for fuels and may actually drive up fuel prices, especially given demand is only projected to increase as the economy recovers from COVID. The commenter adds that chilled domestic production also risks undermining EPA's greenhouse gas reduction goals because it will greatly increase the risk of carbon leakage (*i.e.*, increase importation of higher carbon intensity fuels produced in countries with relatively less stringent regulations). In brief, the commenter states that any final rules need to incorporate flexibility for operators and not penalize them if, after taking reasonable steps pursuant to best management practices, flaring is unavoidable.

Response I-17-7: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>31</sup> See also Response I-17-6 of this Chapter.

### ***17.2.3 Flaring Control Efficiency/Monitoring***

Comment: Commenter (0844-EDF *et al.*) states that their study of flares in the Permian Basin found that 10 percent of all flares were either unlit or only partially functioning.<sup>32</sup> The commenter recommends that EPA adopt effective monitoring and reporting requirements to effectively address this widespread issue. Further, the commenter urges EPA to adopt regulations requiring that in any case in which flaring does occur, flare efficacy is improved to 98 percent control efficiency on a continuous basis.

Commenter (0844-EDF *et al.*) points out that there will still be residual flaring of associated gas due to phase-in of requirements and all nonroutine flaring. To minimize the resulting emissions, the commenter recommends that EPA enhance monitoring requirements and ensure flares are operating at optimum efficiency and deploying technologies that will help prevent malfunction. Accordingly, the commenter suggests that EPA exercise its authority under sections 111 and 114 of the Clean Air Act (CAA) to both enhance operational requirements and require well operators to report any flaring incidents, including both the total time of flaring and the total estimated emissions [commenter includes a description in their comment letter].

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<sup>31</sup> 87 FR 74779-74780.

<sup>32</sup> EDF, Flaring Aerial Survey Results (2021), <https://www.permianmap.org/flaring-emissions/> (last accessed Oct. 27, 2021).

Response I-17-8: See discussion in section IV.H.2 of the December 2022 Supplemental Proposal preamble.<sup>33</sup>

#### ***17.2.4 Reporting Unplanned and Planned Flares***

Comment: Commenter (0844-EDF *et al.*) requests that in the case of unplanned flaring for reason of emergency, well operators should submit their report no later than 12 hours after the event,<sup>34</sup> and should be required to provide justification for the flare, demonstrating that its reason for flaring falls within EPA's narrowly defined set of emergency circumstances. The commenter (0844-EDF *et al.*) suggests that, to the extent that EPA chooses to permit flaring in other narrowly defined circumstances, such as pressure testing,<sup>35</sup> EPA require the operator to provide notice both no later than 24 hours before the event (at which time the operator should provide a projected estimate of total time and emissions) and no later than 12 hours after the event (at which time the operator should provide an estimate of time and emissions actually produced). The commenter contends that planned flaring instances should be rare and subject to specific EPA restrictions.

Response I-17-9: The EPA has revised the circumstances that allow for temporary flaring due to upset or malfunction. See 40 CFR 60.5377b for the revised rule text. See also the revised text for reporting and recordkeeping with respect to the obligation of affected facilities to record and report on upset and malfunction events that lead to a period of flaring. The EPA disagrees with the commenter on the need to require immediate notification of a malfunction that results in a flaring event. While such flaring events are a deviation from the requirement to avoid flaring by employing another form of emissions control, the EPA is not persuaded that a deviation requires immediate notification to the Administrator. The EPA also points out that such events are unfortunate but foreseeable, such that EPA has required that flares be immediately available to address malfunction events.

### **17.3 General Support/Opposition Regarding Venting**

#### ***17.3.1 Necessary Venting***

Comment: Commenters (1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*) state that none of the November 2021 Proposal's compliance options are workable for the oil-producing members of the Conventional Group. According to the commenters, for many conventional oil wells in Pennsylvania and New York, a gas sales line is not reasonably available. The "associated gas" produced at these conventional oil and gas well sites would not be sufficient to sustain a flare, much less justify the changes and capital expenditures needed to attempt to use the gas onsite. EPA must expressly allow Pennsylvania and New York conventional oil producers to vent the small volumes of "associated gas," which is the only safe and environmentally sound method of dealing with associated gas at some Pennsylvania conventional oil wells. If finalized, the commenters contend that EPA's November 2021 Proposal

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<sup>33</sup> 87 FR 74792.

<sup>34</sup> See 2 Colo. Code Regs. 404-1 § 903(a)(2).

<sup>35</sup> 2 Colo. Code Regs. 404-1 § 903(d)(1)(B),(E) (accessible at <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=9245>).

would undoubtedly eliminate Venango Sands production in Pennsylvania's Venango County, the county in which Pennsylvania's first oil well was drilled in 1859.

Commenter (0831-American Exploration and Production Council (AXPC)) supports non-venting except for when there is technical infeasibility, safety concerns or other similar issues. However, the commenter states that it is also important to understand that there is a limitation on non-pipeline solutions for associated gas. The commenter adds that there are some technological solutions but there are certain circumstances when even the most advanced technological solutions do not work. Also, the oil and natural gas operator does not necessarily have the rights to surface property that would be necessary to implement a pipeline or non-pipeline solution – this is not something that operators have the power to do, nor does EPA have the authority to provide them with this power. Thus, the commenter wants to ensure that EPA understands that “access to a sales line” does not equate to availability.

Commenter (0814-Independent Petroleum Association of America (IPAA) *et al.*) states that EPA's efforts to restrict venting of associated gas may be appropriate for certain scenarios; however, there may be situations where new wells or existing wells that currently do not have gas sales pipeline line to them are either not available, feasible or economic. The commenter adds that there may not be adequate volumes or quality of gas to use onsite or route to a flare. The commenter recommends that EPA allow exemptions for these situations, especially for marginal/low production wells, where lack of adequate volumes or gas quality preclude its use onsite or routing to a flare. In all other situations, the commenter recommends that EPA allow options that operators can implement that best fit their operations.

Response I-17-10: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>36</sup> See also Response I-17-9 of this Chapter.

### ***17.3.2 Eliminate Venting***

Comment: Commenter (0770-Northern Plains Resource Council (NPRC)) calls for the elimination of routine venting of associated gas from oil wells, and the requirement for owners and operators to route gas to sales lines, where available. Commenter (0578-Grand Canyon Trust (GCT)) supports EPA's November 2021 Proposal to eliminate venting at wells with associated gas except in the case of emergency. Commenter (0444-Damascus Citizens for Sustainability (DCS)) supports the November 2021 Proposal to prohibit venting of methane, which is a major source of emissions. Commenter (0437-New York Office of the State Comptroller (NYOSC)) supports the proposed measure to end the venting of associated natural gas.

Commenter (0808-American Petroleum Institute (API)) supports the elimination of venting from “each oil well that produces associated gas and does not route the gas to a sales line” with additional clarifications. While EPA's November 2021 Proposal is overly broad in its description, the commenter generally supports and recognizes the environmental benefit of the elimination of venting of associated gas from oil wells that do not currently route gas to a sales line (EPA's proposed Option 2).

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<sup>36</sup> 87 FR 74780.

Response I-17-11: See discussion in sections IV.F.2.a.ii and IV.F.2.a.iii. of the December 2022 Supplemental Proposal preamble.<sup>37</sup>

## **17.4 General Support/Opposition of 95 Percent Emission Reduction**

Comment: Commenter (0391-KBIC, 0781-NTAA, 0605-Muscogee (Creek) Nation, 0943-Sault EPD, 0833-Ute EPD) believe that EPA should consider standards requiring greater than 95 percent emissions reduction when associated gas cannot be put to productive use.

Commenter (0808-API) recommends that, if associated gas cannot feasibly and economically be recovered to a sales line, that gas be required to be captured for a beneficial use or flaring the gas such that 95 percent control efficiency is achieved.

Response I-17-12: See discussion in sections IV.F.2.a.iii and IV.H.2 of the December 2022 Supplemental Proposal preamble.<sup>38</sup>

Comment: Commenter (0831-AXPC) states that it is unclear what EPA means when they say “continuous” when it comes to a 95 percent destruction. While the commenter does not have regulatory text to directly comment on, they believe that EPA means that it is a 95 percent threshold based on an average over at least 24 hours. The commenter also recommends that there be exemptions for when vent gas rates are insufficient to support continuous flare operation. In those situations, supplemental flare fuel gas would be required to support flare operation resulting in an emission profile exceeding that resulting from the minimal existing vent gas. This situation becomes more common as wells age and overall production rates decline.

Commenter (0831-AXPC) notes that operating a flare in compliance with 40 CFR 60.18 does not demonstrate that the flare is constantly achieving the required 95 percent Destruction Rate Efficient (DRE). The commenter explains that there have been studies that show that oil and gas flares can achieve an average DRE in excess of 95 percent (*e.g.*, Steffes).<sup>39</sup> They add that extreme weather condition can temporarily impact a flares DRE, however that annual average DRE will be equal to or greater than 95 percent.

Commenter (0831-AXPC) states that, for oil wells that produce little or intermittent associated gas, a flare or combustor cannot operate efficiently or in compliance with 40 CFR 60.18 without additional gas being supplemented (propane from a propane tank) to provide fuel gas for the pilot and sweep gas. For these situations, it is common to install a pit flare with an auto ignitor that will ignite the gas when present. According to the commenter, these are not as efficient as an engineered flare that complies with 40 CFR 60.18, but it is the best technology for the situation.

Response I-17-13: Regarding monitoring requirements for the flare, see discussion in section IV.H.2 of the December 2022 Supplemental Proposal preamble.<sup>40</sup> Regarding control efficiency

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<sup>37</sup> 87 FR 74780.

<sup>38</sup> 87 FR 74781 and 74794.

<sup>39</sup> Combustion Efficiency Performance Testing of Pressure Assisted Flares Utilizing Passive FTIR, Sage Environmental Consulting for Steffes Corp. (Testing Conducted Sept. 2015, Report Apr. 2016).

<sup>40</sup> 87 FR 74792-93.



requirements for the flare, see discussion in section IV.H.2 of the December 2022 Supplemental Proposal preamble.<sup>41</sup>

## **17.5 Associated Gas from Wildcat/Delineation Wells**

Comment: Commenter (0808-API) asks for special considerations for handling associated gas at wildcat and delineation wells. The commenter notes that EPA did not allow provisions for wildcat or delineation wells in its proposal. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. Like provisions within NSPS OOOOa for well completions, the commenter recommends that EPA allow special considerations for handling associated gas at these types of operations. Specifically, the commenter recommends that any associated gas initially generated from wildcat or delineation wells be routed to a combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways).

Response I-17-14: See discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>42</sup> EPA has defined associated gas to exclude gas from exploratory and wildcat wells, if and until those wells become producing oil wells with associated gas. See the definition of associated gas in 40 CFR 60.5430b and 60.5430c.

## **17.6 Routing Associated Gas to Sales Line**

### ***17.6.1 Associated Gas with No Sales Line and Low Combustibility***

Comment: Commenter (0955-Vaquero) states that many older fields with heavier hydrocarbons have little to no produced gas. Furthermore, the commenter adds that certain fields require water or inert gas injection to produce oil resulting in associated gas streams diluted with inert gas (nitrogen, carbon dioxide, and water) that require excessive amounts of imported assist gas to achieve its lower flammable limit (LFL). For example, the commenter notes that the associated gas in parts of Wyoming are approximately 97 percent carbon dioxide and 3 percent hydrocarbon, with no combustible field gas available. As such, propane must be added to until the mixture is 11 percent molar volume of propane (or 333 Btu/scf) to reach its LFL.<sup>43</sup> As shown in Table 1 of the commenter's submission, this would require the addition of over 3 gallons of propane per Mscf combusted at a cost of over \$5,000 per ton of VOC removed. Further, the commenter states that the supplemental firing of propane introduces additional VOC to the gas stream. As a result, the commenter notes that the combustion control device would require 98.9 percent destruction efficiency to achieve a net control efficiency of 95 percent to account for the additional propane. Finally, Table 1 of the commenter's submission shows that 36.75 tons of CO<sub>2</sub>e are emitted per 500,000 Mscf (or 1 ton of VOC). According to the commenter, the addition

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<sup>41</sup> 87 FR 74794-95.

<sup>42</sup> 87 FR 74780.

<sup>43</sup> Robert N. MacCallum, PhD, P.E., et al. Flammability of Mixtures of CO<sub>2</sub> and Hydrocarbons. <http://www.trimeric.com/assets/flammability-of-mixtures-of-co2-and-hydrocarbons.pdf>

of propane and subsequent combustion controls of modicum of methane while emitting an additional 2.9 tons of CO<sub>2</sub>. This results in a net increase of CO<sub>2e</sub> by 7.9 percent.

Commenter (0955-Vaquero) states that such associated gas has no utility as a fuel source and must be collected and compressed for offsite utilization or sequestration. The commenter explains that these fields are often sparsely mined and have no pipeline or electrical infrastructure resulting in the need to install miles of gathering and transmission lines as well as gas-fired field compression ignition engines. A gas-gathering pipeline is estimated to cost \$178,000 per inch-mile<sup>44</sup>, meaning that a 6" pipeline traveling 10 miles would cost over \$10MM not counting the costs of compression, operation, and maintenance. The commenter notes that such costs do not consider the secondary environmental impacts from construction, compression, and pipeline operations such as emissions, leaks, and ecosystem disturbance. As such, the commenter requests that the proposed rule provide a categorical exemption from control requirements for associated gas that has a heating value below its LFL. Operators may demonstrate this exemption by maintaining records of associated gas composition and LFL.

Commenter (0598-Countrymark Energy Resources, LLC) is concerned that, because of the low potential to emit (PTE) for their wells (i.e., low pressure and low gas to oil ratio (GOR)), they are unable to economically justify the cost of compliance with an increase in oil or gas sales, for any operational scenario. Further, the commenter states, there is no infrastructure in proximity to a high percentage of their oil wells to be able to sell gas for additional revenue. The commenter states that EPA has not entertained cost discussions with industry and specifically, small businesses were not consulted to see how the costs will impact their operations or overall viability.

Response I-17-15: See discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>45</sup> With respect to the estimated cost of routing to a sales line, please see EPA's analysis of cost with respect to routing to a sales line. In the final rule, the EPA has adopted a prohibition on long-term routine flaring for new wells. For modified wells that demonstrated that routing to a sales line nor any of the alternative uses are technically feasible, the option to flare remains available. Within the presumptive standard in EG OOOOc, for designated well facilities with over 40 tpy methane that demonstrate that routing to a sales line nor any of the alternative uses are technically feasible, the option to flare remains available.

### ***17.6.2 Approval of Routing Gas and/or Using Associated Gas Onsite***

Comment: Commenter (0727-Oklahoma Secretary of Energy and Environment (OSEE) and Oklahoma Department of Environmental Quality (ODEQ)) states that for facilities with existing gas-powered equipment, using the gas onsite seems more logical than sending the gas off site through a sales line and bringing other gas in to power the equipment. Further, the commenter notes that routing gas to a sales line and using the gas onsite appear to be equally viable options.

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<sup>44</sup> Global Energy Monitor.

[https://www.gem.wiki/Oil\\_and\\_Gas\\_Pipeline\\_Construction\\_Costs#:~:text=American%20Petroleum%20Institute%202017%20Estimate,In%20its%20study&text=Combined%20with%20the%20estimate%20of,or%20%243.32%20million%20per%20km.](https://www.gem.wiki/Oil_and_Gas_Pipeline_Construction_Costs#:~:text=American%20Petroleum%20Institute%202017%20Estimate,In%20its%20study&text=Combined%20with%20the%20estimate%20of,or%20%243.32%20million%20per%20km.)

<sup>45</sup> 87 FR 74780.

The commenter states that it is unclear why EPA distinguishes between the two and prefers one scenario over the other.

Response I-17-16: See discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>46</sup>

### ***17.6.3 Exemptions for Routing to Sales Line***

Comment: Commenter (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) suggests in situations where gas sales pipelines to new or existing wells are not available, feasible or economic, or too small in volume, EPA allow exemptions for these situations, especially for marginal/low production wells. In all other situations, the commenter recommends that EPA allow operators the option to implement a proposed requirement (sales pipeline, onsite fuel use, another useful purpose or route to a flare or other control device that achieves 95 percent reduction in methane and VOC emissions) that best fit their operations.

Response I-17-17: See discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>47</sup>

### ***17.6.4 Use of Associated Gas when a Sales Line is Available***

Comment: Commenter (0740-Utah Petroleum Association (UPA)) states that the wording of the November 2021 Proposal suggests that the gas cannot be used as an onsite fuel source or routed to a flare or other control device if a sales line is available. The commenter does not agree with this approach. The commenter recommends that the rule allow using the gas as an onsite fuel source whether a sales line is available or not. According to the commenter, this will improve cost effectiveness of the rule by not requiring expensive retrofits to add new power sources in locations such as rural Utah that may not have ready access to electrical power or might have other limitations and other obstacles as described above. Furthermore, the commenter adds that, even if a sales line is available, most oil wells in Utah do not produce gas at a high enough pressure to put the gas into a sales line and therefore would require a compressor at substantially added cost and additional use of energy and associated emissions. The commenter reports that the Bureau of Land Management recognized this fact in their final waste gas prevention rule wherein they included exemptions from requirements to route gases to a sales line where the operator determines that compliance would be technically infeasible or unduly costly.<sup>48</sup>

Response I-17-18: The CAA with respect to NSPS compels EPA to identify the Best System of Emission Reduction, BSER, and to set the standard applicable to affected sources. In this instance, the EPA has included options (alternatives) to BSER where an operator finds it to their advantage to implement an alternative that achieves equivalent emission reductions. Exercising any of those options is at the discretion of the operator and does not require EPA approval

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<sup>46</sup> 87 FR 74779.

<sup>47</sup> 87 FR 74779.

<sup>48</sup> As cited by the commenter, “See “Waste Prevention, Production Subject to Royalties, and Resource Conservation” final rule; Federal Register Vol. 81, No. 223; November 18, 2016; p. 83008; rule language as adopted at 43 Code of Regulations, Chapter II §3179.203(c)(2) on p. 83086.”

because the alternatives are included in the rule itself (EPA has already determined equivalent emission reductions). For sources where routine flaring is allowed under the NSPS OOOOb and OOOOc EG, the operator must demonstrate that non-flaring options are infeasible on an annual basis (except for presumptive standard in EG OOOOc for wells with 40 tpy methane or less). See discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>49</sup>

#### ***17.6.5 In Support of Use or Combustion in the Case of No Sales Line Accessibility***

Comment: Commenter (0808-API) agrees with EPA's statement that access to a sales line does not equate to availability of a sales line. Although in agreement, the commenter summarizes a few challenges for EPA's awareness and consideration:

- Topography: Mountains, rivers, lakes, *etc.* can limit a producer's ability to connect into a pipeline.
- A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line. In most cases, the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added and if the quality of gas meets their required specifications. Additionally, capacity issues could exist even in cases where the production company is also responsible for the gathering system.
- Necessary permits and right of way (ROW) must be obtained for the pipeline from the well site to the natural gas gathering system. Permits and ROW are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary ROW can be difficult and may require a court order. On certain federal lands, operators have been required by Bureau of Land Management in recent years to reroute proposed pipelines or to adjust installation techniques, which significantly delays the completion of gathering systems. On private lands, individual landowners may deny rights.
- The natural gas must meet the specifications of the natural gas gathering line. Contracts with the gathering company include specifications for entering the gas gathering line, such as allowable concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. The natural gas gathering system owner ultimately controls when an operator can send gas to sales.
- The natural gas gathering line must be operational. Natural gas gathering lines can be temporarily down or unavailable for a multitude of reasons including, but not limited to, compressor maintenance or repair, line maintenance, line inspection, a gas plant being shut down, or temporary reductions in capacity. In some instances, a well will be connected to sales, but if a compressor station has an emergency upset, then the wells tied into the gathering system will not be able to send gas through the pipeline. These instances are often episodic, temporary, and not in the well operator's control.

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<sup>49</sup> 87 FR 74779.

Commenter (0808-API) states that, due to the various challenges described, EPA is correct in allowing the beneficial reuse of gas onsite or combusting the gas where accessing the pipeline is not available or technically feasible.

Response I-17-19: See discussion in section IV.F.2.a.iii of the December 2022 Supplemental Proposal preamble.<sup>50</sup> See also Response I-17-3 of this Chapter.

#### ***17.6.6 Costs of Routing Associated Gas to Sales Line***

Comment: Commenter (0946-Michigan Oil and Gas Association (MOGA)) provides a discussion regarding the innate issues regarding bringing associated gas to a “useful purpose rather than flared.” As stated in Comment #9 of the commenter’s letter, every producer would like the ability to sell all produced assets. The commenter notes, however, that the ability and cost are often not feasible because of conflicting regulations, landowner & community objection, Public Service Commission (PSC) restrictions, and the associated cost of pipeline, metering, compression, and transfer gate installation.

Commenter (0946-MOGA) reports that many wells drilled in the United States are not located at convenient spots. The inconvenient locations are in rural locations such as farmland, forests, and sparsely populated areas. Because these areas are remote and often isolated, the commenter notes that transmission or gathering lines that collect gas are located closer to major distribution areas. The commenter states that natural gas produced in these remote areas are referred to “stranded gas.” According to the commenter, the term “stranded” is used because the value of the gas will not pay for the pipeline needed to move the gas to a distribution line. If multiple wells are in a micro-geographic region, then connecting the flowlines to a distribution point, may justify the installation. However, the commenter states that landowners may object to having flowlines in their fields and local communities may not want subsurface piping down road easements, crossing driveways and stream crossings. So, the natural gas stays stranded, except for wellsite fuel or power generation. The commenter requests that EPA discuss and clarify whether the Biden Administration is proposing financial, regulatory, and political support necessary to install natural gas lines to move stranded gas to a “useful purpose rather than flared?”

Commenter (0946-MOGA) explains that the determination for flowline installation is based on economics for the estimated reserves. The commenter notes that a producing company may consider, based on current commodity price and volume of gas generated, the installation of a flowline to bring gas to market. However, the commenter adds that the purchaser of the natural gas will evaluate their costs to install the same flow line but incorporate a profit margin of \$2.00/MSCF or more and subsequently charge the producer for control equipment, emergency shut-off devices, custody transfer equipment and more. According to the commenter, because distribution companies are regulated by the Federal Trade Commission and individual state's PSC, these are over-designed for commercial and residential safety and are extremely expensive.

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<sup>50</sup> 87 FR 74779.

Response I-17-20: See discussion in section IV.F.2.a.iii of the December 2022 Supplemental Proposal preamble.<sup>51</sup> See also Response I-17-3 and Response I-17-21 in this Chapter below.

Comment: Commenter (0425-Darrah Oil Company, LLC (Darrah)) suggests a rule requiring separation and selling of gas does not consider cost burdens and might create more environmental damage than it protects. For example, the commenter notes that the environmental impact of creating the plastic pipe and safely laying it in the ground may outweigh the lifetime of protection it was trying to create. The commenter asserts that any requirements mandating separation or sales should be stricken.

Response I-17-21: New Source Performance Standards are based on the best system of emission reductions (BSER), which could be particular technology or other measure that has been adequately demonstrated to improve emissions performance for a specific industry or process. In determining the BSER, EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements. The commenters' request for political and financial support for the installation of gathering and collection systems for associated gas is beyond the scope of the standards EPA is setting in this rulemaking. With respect to regulatory support, the EPA is not imposing a "one size fits all" requirement to compel the construction of collection systems to bring the gas directly to market. For all operators with associated gas, the final rule preserves the ability of operators to choose their best option that produces emission reductions equivalent to the standard. The final rule requires operators of new wells to route associated gas to a sales line within 24 months. Operators may choose from several other non-flaring alternatives in the rule at their discretion. These new sources may not flare but for specified exceptions for up to 24 hours in the case of malfunctions or upsets, and lesser periods for other circumstances that compel a source to flare.

For designated facility wells with over 40 tpy methane that will be subject to state plans in accordance with OOOOc EG, BSER (presumptive standard) is to connect to a sales line or similarly choose an alternative. The EG includes a subcategory for wells that have 40 tpy methane or less. In addition, EPA recognizes that for existing wells, states have flexibility under CAA 111(d). We think that this subcategory and flexibility for existing wells will address the commenters concern that associated gas could be stranded without any available or cost-effective route to a sales line.

As a general matter, the EPA does not consider flaring associated gas indefinitely as necessary for many sources, given the number of state jurisdictions that have employed various regulatory systems to curtail routine flaring. Similar to state standards such as New Mexico, and Colorado, the EPA has chosen to set a firm deadline to end routine flaring from new wells, while providing alternatives for modified wells and existing wells that address the concern under some circumstances routing to a sales line may not be feasible. The EPA did extensive analysis on the costs of addressing emissions from associated gas. However, within this rule, EPA did not address the comment about the alleged environmental impact of manufacturing and installing gas gathering or oil pipelines, compared to the practice of routine flaring, because the purpose of this NSPS is to address emissions from the oil and gas category. This comment is out of scope. Other NSPS and National Emission Standards for Hazardous Air Pollution address emissions from

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<sup>51</sup> 87 FR 74779.

categories that produce (manufacture) the material and equipment used by the oil and gas sector. In the context of this rulemaking, an analysis of the kind the commenter asks for, even if such an investigative framework could be devised, would not contribute to a better NSPS or EG for the oil and gas category.

Comment: Commenter (0946-MOGA) notes that EPA does not consider the requirement of additional equipment including compression and dehydration required to make stranded gas “useful.” The commenter states that natural gas will require dehydration because of contract specifications. According to the commenter, if the heating content of the natural gas is greater than the contract limitations, gas conditioning will have to be implemented to sell the gas. The commenter adds that compression will also be required to “boost” the gas pressure high enough to enter the sales and/or transmission line. The commenter provides that compressors typical cost roughly \$50,000 per month to lease and service with an upfront cost of roughly \$500,000 to transport and install. The commenter notes that the inevitable depletion and production decline will make the operation of this equipment uneconomical over time. The commenter believes, as noted in other comments provided by the commenter, that EPA's estimates and feasibility for bringing stranded gas to market fall far short of the actual costs and the breakeven potential, if any.

Commenter (0946-MOGA) expresses that they would support federal regulations allowing oil and gas producers to bypass restrictive PSC rules and regulations to directly sell production and associated gas directly to local landowners, farmers, businesses, and residential dwellings.

Response I-17-22: EPA has established that the introduction of associated gas into a sales line is BSER. Our data and that submitted by other commenters to the proposed rule indicate that alternatives to routine flaring are practical, in wide use, and increasingly cost-effective. Two state jurisdictions (NM and CO) have preceded ahead of EPA to prohibit long-term routine flaring, while two more (ND and TX) have placed significant restrictions and required similar analyses prior to allowing routine flaring. Please see the technical support document in the docket regarding the cost of achieving BSER. The cost analysis that EPA has provided is based upon industry estimates and are comprehensive and detailed enough to reasonable estimates of typical costs that can be expected by operators complying with BSER by routing and connecting to a sales line. While not every source will find their costs to be at the exact level found in the analysis, our estimate is based on the best data available and used by the industry for various types of similar analyses.

EPA agrees with the commenter that certain users of associated gas should be able to continue to use the gas, such as a well operator that uses the gas for home heating on the site of or near the well itself. EPA considers such use to be within the meaning of the criteria of “Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve” since in the absence of such use, the user would be required to find an alternative source of fuel for home use.

Comment: Commenter (0844-EDF *et al.*) points out that currently, most of the associated gas is captured and transported by sales line, and this will likely continue to be the preferred approach of most operators. When new wells are drilled in the vicinity of existing gathering systems, they

can be quickly and cheaply connected to the existing system.<sup>52</sup> The Rystad report shows that connecting wells to gathering line infrastructure is not only highly cost-effective but profitable for operators, with an average net negative cost of \$3.10 per thousand cubic feet (mcf).<sup>53</sup>

As a general practice, the commenter (0844-EDF *et al.*) states that EPA's determination of the BSER for controlling emissions from an affected facility is informed by its analysis of the control options for that emissions source. The commenter suggests that, while EPA recognizes that routing gas to a sales line is a highly attractive option for operators, the Technical Support Document (TSD) does not accurately describe the availability of this option, which is a critical shortcoming for purposes of determining BSER. The commenter notes that the TSD assumes that "access to a sales line" either is or is not available to an operator, without the operator having any ability to influence such availability, much less ensure it. Because gathering systems and natural gas processing capacity are more commonly owned by midstream companies, rather than the producers themselves, and because many of the options for avoiding routine flaring are not plug-and-play control technologies (unlike installing a compressor, which is exactly such a solution in the case of insufficient wellhead pressure), there has been a tendency to view the availability of infrastructure necessary for capture and sale as largely outside of producers' control. This is, indeed, how access to a sales line is treated in the TSD. According to the commenter, this key foundational assumption is not reality; nor is it the prevailing practice among producers that are successfully curtailing routine flaring.<sup>54</sup> The vast majority of routine flaring is fundamentally driven by business decisions, not technical constraints. The practical reality is that operators have substantial and relatively low-cost or negative-cost opportunities to ensure access to take-away capacity for their associated gas.

First, the commenter (0844-EDF *et al.*) states that it is worth noting that the oil and gas industry exists to produce and sell their products – their business model depends on getting these products to market. The commenter states that the United States has billions of dollars in infrastructure in place dedicated to producing, gathering, processing, transporting and delivering natural gas. Investment in this infrastructure responds to the market demands of oil and gas producers and suppliers. Operators of gas wells know how to ensure that they can capture and route gas for sale. They derive their revenues predominately from natural gas, and while there are some wasteful practices, they do not engage in routine flaring. The commenter notes that these operators make sure that the wells are connected to gathering lines with available capacity prior to bringing those wells into production, and when downstream facilities are not operating for extended periods of time, gas wells are commonly temporarily shut in.

The commenter (0844-EDF *et al.*) reports that routine flaring of associated gas is widespread not because gas from an oil well has a different value than gas from gas wells (although prices do vary somewhat by location),<sup>55</sup> but because of the comparative values of gas and oil. Oil has such a higher relative value than gas in recent years that many oil well operators optimize for oil production to the point of treating the associated gas as a waste product. Nevertheless, the commenter notes that, because associated gas does, in fact, have economic value, capturing it for

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<sup>52</sup> Attachment W at pg. 43 of the commenter's submission.

<sup>53</sup> Id. at 11.

<sup>54</sup> Attachment W at pg. 79-80 of the commenter's submission.

<sup>55</sup> See, e.g., id. at 43-44, 78.



sale typically has net negative costs.<sup>56</sup> According to the commenter, even in a situation where an operator might not be able to ensure access to gathering capacity without incurring some net costs, those costs are likely to be modest overall even before (and certainly after) offsetting the value of the gas.<sup>57</sup> The commenter notes that this is quite different from a typical pollution control requirement that imposes only costs.

Second, the commenter (0844-EDF *et al.*) states that, as the Rystad report makes clear, operators can make operational and commercial adjustments to improve or ensure their access to a gathering system (as well as make alternative arrangements for periods of unavailability).<sup>58</sup> For example, the commenter explains that operators can provide information to midstream companies in advance about expected timing and quantities of gas production, allowing gathering system operators to expand capacity in a timely manner. The commenter adds that operators can require that their new wells are connected to a gathering system with available capacity prior to beginning production.<sup>59</sup> They can also enter into contractual arrangements that guarantee firm gathering or trunkline capacity, and/or that penalize midstream gatherers and processors for downtime.<sup>60</sup> According to the commenter, there are some costs to coordination, information sharing, and negotiating and paying for contractual guarantees, but by and large these should be quite small compared to typical hardware-based pollution control investments. Regardless, the commenter contends that these options make it clear that operators commonly have substantial control over their access to gathering capacity and can exercise this control at typically net negative costs to avoid routine flaring.

Response I-17-23: See Response I-17-21 of this Chapter. EPA generally agrees with the comment. The final rule requires that new sources must route to a sales line, or employ another non-flaring option to handle the associated gas. For modified sources under OOOOb, and existing sources under OOOOc EG, sources with more than 40 tpy methane must evaluate and certify that alternatives to flaring are not feasible before recurring to flaring. For sources with 40 tpy methane or less, the EPA has set BSER to flaring associated gas. EPA adopted routing to a sales line for new sources as BSER because we agree with the commenter that new wells will have the means to route to a sales line.

#### ***17.6.7 “Affected Facility” Definition***

Comment: Commenter (0793-PBPA) asserts that they believe that EPA’s November 2021 Proposal remains legally objectionable. The commenter states that a “standard of performance” is an emissions standard that “reflects the degree of emission limitation achievable through the application of the best system of emission reduction ....”<sup>61</sup> That is, according to the commenter, a standard of performance should reflect the capability of control technologies, not mandate reduced operation of control technologies. The commenter states that BSER stands for “best system of emission reduction,” not operation reduction, and Congress designed section 111 of

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<sup>56</sup> Id. at 11.

<sup>57</sup> Id. at 39.

<sup>58</sup> Id. at 45.

<sup>59</sup> Id. at 80.

<sup>60</sup> Id.

<sup>61</sup> 42 U.S.C. §7411(a)(1).

the CAA to promote technology development.<sup>62</sup> The commenter adds that Congress in section 111 of the CAA differentiated between “operational standards” in section 111(h) (which might include operational reductions or restrictions) from “standards of performance” in sections 111(b) and (d), and Congress only permitted EPA to pursue the former in rare circumstances mostly limited to fugitive emissions.<sup>63</sup>

The commenter (0793-PBPA) recommends that EPA define the “affected facility” to only include oil wells producing associated gas where a sales line is inaccessible,<sup>64</sup> with inaccessibility including an analysis with exceptions for (a) distance from and availability (capacity-wise) of takeaway and processing facilities, including the cost to build takeaway infrastructure, (b) inability to acquire rights-of-way, (c) the composition of associated gas and whether it meets processing and pipeline specifications, and (d) volumes of expected associated gas.

Using this alternative definition, the commenter (0793-PBPA) recommends that the BSER be to beneficially use the associated gas (for example, as onsite fuel) or to route associated gas to a flare or other control device that achieves at least a 95 percent reduction in VOC emissions. According to the commenter, compelling use of non-flaring technologies should be off the table<sup>65</sup> because the availability of non-flaring technologies would vary by site. For example, the commenter states that if an oil producing site beneficially uses 96 percent of associated gas production for gas lift operations, the remaining 4 percent would need to be flared if the site is stranded from a takeaway pipeline perspective. That “excess” 4 percent of gas would be difficult to market due to its small volume and, for the same reason, non-flaring technologies may be unavailable or cost prohibitive. The commenter notes that it may be different from an oil producing site where larger volumes of gas cannot be put to beneficial use at all. The commenter suggests that using this alternative definition would also have the following benefits:

- It would ensure that these new federal regulations do not unnecessarily overlap with existing state regulations. These existing state regulations already prohibit or limit venting and/or flaring under appropriate circumstances, are enforced by agencies with relatively more on-the-ground knowledge than EPA and reflect states’ interests in conserving their own resources.<sup>66</sup> This is particularly important for the forthcoming EGs as it would allow states to develop plans that consider their own regulations and other local considerations.

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<sup>62</sup> See, e.g., 79 Fed. Reg. 1,430, 1,465 (Jan 8, 2014).

<sup>63</sup> 42 U.S.C. §7411(h)(2).

<sup>64</sup> 86 Fed. Reg. at 63,238 (“As an alternative, the EPA is soliciting comments on defining the affected facility as each oil well that produces associated gas and does not route the gas to a sales line.”).

<sup>65</sup> Id. at 63,237 (“The EPA is interested in information on, and the feasibility, of options to utilize associated gas in some useful manner in situations where a sales line is not available. In addition to use as fuel, such options could include conversion technologies where methane is converted into hydrogen or other added value chemicals. The EPA is interested in information on these, as well as other, technologies.”).

<sup>66</sup> Id. at 63,237 (“Typically, State oil and gas regulatory agencies (or, on certain public and Tribal lands, the BLM) regulate venting and flaring of associated gas from oil wells to ensure oil and natural gas resources are conserved and utilized in a manner consistent with their respective statutes. State oil and gas regulatory agencies typically encourage, and in some cases require, capture (conservation) over flaring, then flaring over venting.”).

- It would focus regulation on wells that have the greatest potential of uncontrolled emissions—those that are truly stranded from a takeaway pipeline perspective.

Response I-17-24: EPA is not substantively responding to this comment because of comments received on the November 2021 Proposal, EPA proposed a different affected facility definition for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.F.1 of the December 2022 Supplemental Proposal preamble.<sup>67</sup>

Comment: Commenter (0938-Texas Oil & Gas Association (TXOGA)) supports an alternative “affected facility” definition that would exclude oil wells that route all associated gas to a sales line as a sensible acknowledgment of the fact that if all associated gas is routed to a sales line, there would be no emissions to control under the standard.

Conversely, commenter (0797-North Dakota Department of Environmental Quality (NDDEQ) and North Dakota Industrial Commission (NDIC)) recommends that EPA not exclude oil wells that produced associated gas from the affected facility definition if they route the gas to a sales line. If adopted, the commenter believes that this alternative proposal will only complicate the reporting process and unduly burden both owners and operators in addition to the delegated entities in charge of ensuring compliance with the rule.

The commenter (0797-NDDEQ/NDIC) states that, since there is no draft regulatory text, the alternative proposal does not explain what documentation would be required for instances where access to the sales line is disrupted. In such a case, the commenter asks whether those oil wells would become an affected facility only for as long as the sales line was disrupted? The commenter further asks whether the reporting party would only report for that specific time period, and would there be an additional notification requirement for those oil wells if they would thus become an affected facility every time the sales line is unavailable? The commenter is concerned that for oil wells that produce associated gas and where sales line access is not a guarantee (as is common in North Dakota) they will be constantly changing their “affected facility” status.

The commenter (0797-NDDEQ/NDIC) states that it is also important to note that along with disruptions to the sales lines themselves, associated gas production can fluctuate significantly from larger oil well sites consisting of multiple oil wells, where predictable decreases in production over time is interrupted by dramatic spikes in production as new oil wells are drilled and brought into production, potentially displacing capacity in the sales lines for gas from older, lower producing wells. The commenter notes that this is in addition to the older wells themselves going through associated gas production fluctuations via workovers and recompletions. In such pipeline capacity situations, the commenter notes that access to a sales line may not be feasible even if there are no issues with the sales line itself. The commenter requires that control devices (such as flares) be operational even if all associated gas is routed to a sales line in case of such issues, as they are expected to occur.

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<sup>67</sup> 87 FR 74778.

The commenter (0797- NDDEQ/NDIC) notes that the original proposed requirement in the November 2021 Proposal states for oil wells routing all associated gas to a sales line “the only requirement would be to certify that this is occurring.” 86 FR 63238. The commenter believes this is appropriate as it should already be known or easily available due to the royalty requirements on the sold gas. The commenter adds that the proposed requirement also allows a continuous record for all destinations of associated gas through either its sale, beneficial use, or control. In addition, the commenter believes it will serve as a reminder that when access to a sales line is not available the only appropriate alternatives for associated gas are beneficial use or control, not venting.

According to the commenter (0797-NDDEQ/NDIC), EPA should adopt the original proposal of the November 2021 Proposal every oil well that produces associated gas would be an “affected facility” and should not adopt the alternative interpretation offered in the November 2021 Proposal of defining the affected facility as each oil well that produces associated gas and does not route the gas to a sales line.

Response I-17-25: EPA is not substantively responding to this comment. Because of comments received on the November 2021 Proposal, EPA proposed a different affected facility definition for this particular affected/designated facility in the December 2022 Supplemental Proposal. For details, please see discussion in sections IV.F.1 of the December 2022 Supplemental Proposal preamble.<sup>68</sup>

Regarding comments on disruption of service, see discussion in section IV.F.2.a.ii of the December 2022 Supplemental Proposal preamble.<sup>69</sup>

## 17.7 Reinjection

Comment: Commenter (0844-EDF *et al.*) points out that in some circumstances, well operators may prefer to reinject associated gas. The commenter explains that reinjection is used widely in Alaska, where 90 percent of associated gas is injected into oil-bearing formations.<sup>70</sup> The commenter adds that reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.<sup>71</sup>

Commenter (0844-EDF *et al.*) states that choosing to reinject associated gas may do so either by drilling a new injection well or by reappropriating an existing inactive production well.<sup>72</sup> According to the commenter, shale reservoirs are particularly well suited to injection because of their large storage capacity: “nanopores” in the rock formation can trap and store greenhouse

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<sup>68</sup> 87 FR 74778.

<sup>69</sup> 87 FR 74780.

<sup>70</sup> See EIA, Natural Gas Weekly Update: Alaska Natural Gas Infrastructure (May 27, 2021), [https://www.eia.gov/naturalgas/weekly/archivenew\\_ngwu/2021/05\\_27/](https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/) (last accessed Dec. 15, 2021).

<sup>71</sup> See Fengshuang Du and Bahareh Nojabaei, A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control, MDPI: ENERGIES (June 19, 2018), <https://www.mdpi.com/1996-1073/12/12/2355> at 25.

<sup>72</sup> See SADIQ J. ZARROUK & KATIE MCLEAN, “Geothermal Wells”, in GEOTHERMAL WELL TEST ANALYSIS, 39-61, 54 (2019).

gasses in an absorbed state.<sup>73</sup> The commenter adds that associated gas may also be injected and stored in natural aquifers, which may be suitable for gas storage when the sedimentary rock formation is overlaid with impermeable “cap” rock, or in salt caverns.<sup>74</sup> According to the commenter, reinjection costs vary depending on various factors, but Rystad finds that on average, costs are \$3.4/mcf, and \$177 per MT of methane flaring avoided.<sup>75</sup>

Response I-17-26: See discussion in section IV.F.1.a.ii of the December 2022 Supplemental Proposal preamble.<sup>76</sup>

## 17.8 Fuel Source or Gas-to-Wire

Comment: Commenter (0844-EDF *et al.*) suggests that in addition to the various methods of gas capture and redirection explored above, well operators can use associated gas for power needs on site and implement a gas-to-power system for local loads.<sup>77</sup> For wells that are not yet connected to the power grid, on-site gas-to-power technology can replace the diesel generators that would otherwise be used to power operations.<sup>78</sup> The commenter states that this is very beneficial from an emissions perspective, since diesel is a highly polluting fuel with elevated levels of nitrogen oxides, particulate matter, and toxic pollutant outputs.<sup>79</sup> They add that it can also provide significant cost saving because purchasing and transporting fuel from offsite carries a significant cost. As a result, the commenter notes that the Rystad reports that fully displacing diesel with associated gas for power demand at the well amounts to \$7-\$10/mcf saved— subtracting the cost of power generator and treatment and assuming 50 mcf per day of power used.<sup>80</sup>

Thus, the commenter (0844-EDF *et al.*) states that operators can significantly reduce both costs and emissions by utilizing available associated gas to meet well pad energy needs. And they can make a profit while doing so: Rystad estimates that on average, on-site use of gas nets a profit of \$8.60/mcf.<sup>81</sup> According to the commenter, this makes it a compelling alternative to routine flaring and an appropriate element of the BSER for reductions of associated gas at oil wells.

Commenter (0844-EDF *et al.*) suggests that another option is to use the associated gas to power a small electricity generation plant that sends power to the grid. The commenter reports that this approach depends on an ongoing supply of a relatively large quantity of gas to make the necessary investments worthwhile, so it is not suitable for every application. But where the gas

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<sup>73</sup> Du and Nojabaei at 25. See also Yuan Chi , Changzhong Zhao, Junchen Lv, Jiafei Zhao and Yi Zhang, Thermodynamics and Kinetics of CO<sub>2</sub>/CH<sub>4</sub> Adsorption on Shale from China: Measurements and Modeling, MDPI: ENERGIES (Mar. 13, 2019) at 1.

<sup>74</sup> See EIA, The Basics of Underground Natural Gas Storage (Nov. 16, 2015), <https://www.eia.gov/naturalgas/storage/basics/> (last accessed Jan. 27, 2022).

<sup>75</sup> Attachment W at pg. 69 of commenter’s submission.

<sup>76</sup> 87 FR 74778.

<sup>77</sup> Pederstad *et al.*, *supra* note 30, at 38.

<sup>78</sup> *Id* at 36.

<sup>79</sup> See EPA, ABOUT DIESEL FUELS (last accessed Dec. 17, 2021), <https://www.epa.gov/diesel-fuel-standards/aboutdiesel-fuels>.

<sup>80</sup> Attachment W of the commenter’s submission at pg. 51.

<sup>81</sup> *Id* at pg. 11.

volumes and grid access are available, the commenter adds that it can also be a net negative cost option.<sup>82</sup>

Response I-17-27: See discussion in section IV.F.1.a.ii of the December 2022 Supplemental Proposal.<sup>83</sup> The EPA proposed a hierarchy of uses that are alternatives to routing to a sales line. The uses suggested by the commenter are within the scope of the option to recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. This would include capture and conversion to liquified natural gas, compressed natural gas, chemical or physical conversion to methanol or similar chemical feedstock, or use in gas-to-wire or gas-to-power processes.

## 17.9 Truck Transport of Compressed Natural Gas

Comment: Commenter (0844-EDF *et al.*) points out that in cases where existing well sites lack adequate existing gathering system infrastructure, or where gathering systems are at capacity on a temporary or ongoing basis, well operators may choose to forego construction of additional gathering capacity or coordination with third-party gatherers and instead convert associated gas onsite into CNG<sup>84</sup> and transport it by road in specialized tanker trucks.<sup>85</sup> The trucks would transport the gas to processing plants, where the gas is prepared to meet pipeline requirements.<sup>86</sup> Trucking can be both a long-term option for existing wells lacking adequate gathering line infrastructure or capacity, and a short-term solution in cases of low capacity due to outages, maintenance activities, or temporary system overload—either at the processing plant (in which case trucks could transfer the gas to an alternative plant) or on the gathering system (in which case the trucks can bypass the initial pipelines and transfer the gas directly to the plant).<sup>87</sup>

Commenter (0844-EDF *et al.*) states that a report from the New Mexico state Methane Advisory Panel, specifically examining CNG trucking, found that CNG trucking is a “portable, scalable and low or negative cost” approach to gas capture.<sup>88</sup> Indeed, the commenter notes that in many cases truck transport ultimately presents little or no additional cost to well operators because operators will incur only minimal net costs or achieve net benefits by reselling the gas. The commenter adds that various factors play into the total expense of a trucking operation, including distance traveled. The New Mexico report, for instance, found that trucking is most efficient

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<sup>82</sup> Id at pg. 72.

<sup>83</sup> 87 FR 74778.

<sup>84</sup> Attachment W of the commenters’ submission at pgs. 10-11.

<sup>85</sup> Anders Pederstad, Martin Gallardo, and Stephanie Saunier, IMPROVING UTILIZATION OF ASSOCIATED GAS IN US TIGHT OIL FIELDS, CARBON LIMITS AS (Prepared for Clean Air Task Force) (Oct. 2015), [https://www.catf.us/wp-content/uploads/2015/04/CATF\\_Pub\\_PuttingOuttheFire.pdf](https://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf) at 33 [hereinafter CARBON LIMITS].

<sup>86</sup> Id.

<sup>87</sup> Pederstad et al. *supra* note 30, at 33.

<sup>88</sup> NEW MEXICO ENVIRONMENT DEPARTMENT & NEW MEXICO ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT: METHANE ADVISORY PANEL (2019), <https://www.emnrd.nm.gov/ocd/wpcontent/uploads/sites/6/OCD-Exhibit6-NMENRDNMED-MethaneAdvisoryPanel-Technical-Report.pdf> [hereinafter METHANE ADVISORY PANEL] at 178. New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at <https://www.emnrd.nm.gov/ocd/wpcontent/uploads/sites/6/Part27-FinalRule3.25.21a.pdf>).

when well sites are within 20-25 miles of a processing plant.<sup>89</sup> For CNG, the commenter states that operators must purchase an onsite compressor, the total one-time cost of which can be approximated at \$200,000 for the equipment and \$50,000 for the installation.<sup>90</sup> The commenter adds that operators will also need to pay the truck drivers, and may need to lease the appropriate trucking assembly.<sup>91</sup>

Commenter (0844-EDF *et al.*) provides that an analysis by ICF International reports that the quantities of gas transport needed for CNG trucking to break even as a method of gas capture—considering the costs of the onsite compressor, equipment lifetime, truck fuel, driver salary, and several other factors—range from 134 mcf to 345 mcf of captured gas per day, depending on gas prices.<sup>92</sup> Importantly, the commenter notes that this total volume need not be collected from a single well: instead, operators may capture gas from multiple wells in the same vicinity.<sup>93</sup> For particularly high producing wells, then, the commenter reports that CNG trucking will constitute a net benefit for operators. And overall, the net costs are reasonable in terms of methane emissions abatement: Rystad’s report finds that on average, CNG trucking will cost operators \$1.8/kcf, or \$94 per MT of methane flaring avoided.<sup>94</sup>

Response I-17-28: See the response to I-17-27. EPA has established that the introduction of associated gas into a sales line is BSER.. Our data and that submitted by other commenters to the proposed rule indicate that alternatives to routine flaring are practical, in wide use, and increasingly cost-effective. Two state jurisdictions (NM and CO) have preceded ahead of EPA to prohibit long-term routine flaring, while two more (ND and TX) have placed significant restrictions and required similar analyses prior to allowing routine flaring. Please see the TSD in the docket regarding the cost of achieving BSER.

For all operators with associated gas, the final rule preserves the ability of operators to choose their best option that produces emission reductions equivalent to the standard. The commenter’s suggestion is one of those alternatives that may be a cost-effective alternative to connection to a sales line in certain circumstances.

## **17.10 New Source Performance Standards**

Comment: Commenter (0831-AXPC) disagrees with EPA’s assumption that since there are no NSPS that regulate associated gas venting and flaring, that one is therefore needed. The commenter notes that there are many emission sources not covered under a NSPS. The commenter reports that emissions from associated gas venting and flaring are regulated under Federal and State New Source Review programs. Further, state and federal regulators charged with oversight of the production of oil and natural gas in their jurisdictions have the primary responsibility over regulating gas flaring and venting as part of their overall obligation. Also, today it is uncommon for associated gas to be vented under normal circumstances for safety

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<sup>89</sup> See METHANE ADVISORY PANEL at 173, 178.

<sup>90</sup> See ICF INTERNATIONAL at 4.

<sup>91</sup> See *Id.*

<sup>92</sup> See ICF INTERNATIONAL at 9.

<sup>93</sup> See *Id.*

<sup>94</sup> Attachment W of the commenter’s submission at pg 39.

reasons, and many state regulations, like North Dakota, prohibit the venting of natural gas and have gas capture regulations that already limit the gas that can be flared without impacting the economics of the industry.

Response I-17-29: EPA disagrees with commenter’s claim that emissions from associated gas are currently regulated under NSR in all instances. The commenter did not provide any evidence to support this claim. EPA agrees that some states regulate emissions from associated gas, but not all states, and many of those state regulations take different approaches to regulation (some are more stringent than others). EPA still finds that regulating associated gas in this rule is necessary and reasonable for all the reasons stated in the 2021 proposal, 2022 supplemental proposal, and final rule. . Among other things, as stated in the preambles to the proposal and supplemental proposal, EPA is addressing methane emissions in an effort to address climate change. In addressing associated gas with the goal of addressing climate change, combustion of methane produces carbon dioxide, which also contributes to climate change. While flaring is preferable to venting associated gas when addressing climate concerns, using the gas for a useful purpose is preferable to flaring it as waste disposal. By incentivizing and regulating the use of gas over disposal, EPA is inducing sources regulated by the NSPS to further reduce climate emissions than if they merely flare associated gas. EPA also points out emissions from flares, even when operating properly, are a source of pollutants with potential to affect human health and the environment. To the extent that such emissions can be avoided by curtailing flaring, this is a direct environmental benefit.

## **17.11 Cost Benefit Analysis**

### ***17.11.1 Cost Benefit Analysis of Flare***

Comment: Commenter (0793-PBPA) states that EPA’s assumption in the 2021 November proposal that the flare capital cost is \$5,719.55 is a significant underestimate. The commenter informs that the “all-in” cost to install a flare is closer to \$61,500, which reflects the cost of a low-pressure flare (\$30,000), ultrasonic flare meter (\$24,000), and labor/material installation costs (\$7,500).

Commenters (0788-350Seattle, 0941-350Silicon Valley, 0948-Quirk) cite a Rystad Energy study commissioned by EDF to note that 84 percent of routine flaring could be eliminated at no net cost to producers.<sup>57</sup> Commenter (0788-350Seattle) notes that when market and nonmarket factors are taken into account (reduced mortality, avoided agricultural losses, avoided work loss from extreme heat), methane reduction benefits are \$4,300/ton, and 85 percent of the targeted measures have benefits that outweigh cost (Global Methane Assessment, UN Climate and Clean Air Coalition).

Commenter (0592/1340-CURED) recommends that EPA implement financial incentives to reduce flaring and other waste hydrocarbon resources. The commenter states that in the U.S., the market drives the economy. The commenter contends that wasting resources equals wasting money only if producers are held accountable for paying for every cubic foot of natural gas that comes out of the ground, whether on public or on private land. The commenter contends that wellhead metering (rather than at the gathering point) should be the point of taxation and royalty



application. To increase the effectiveness of such financial incentivization, the commenter recommends EPA consider sur-taxes for wasted gas. The commenter recognizes that the comment may be more applicable to minerals management agencies at the state and federal levels. If so, the commenter asks EPA to refer these comments to partner agencies and work with them for implementation as part of the plan to reduce emissions.

Commenter (0808-API) suggests that EPA underestimated the cost of installing a flare in its cost benefit analysis. The commenter contends that EPA used a value significantly lower than EPA estimates for flares for other affected facilities.

The commenter (0808-API) recommends that EPA re-evaluate the cost effectiveness using more relevant cost information that is consistent with how flares are costed for other emission sources. Throughout the TSD for the November 2021 Proposal, the commenter states that EPA has assumed various costs with respect to installing a flare or other combustion device.

In review of EPA's cost evaluation data for associated gas from oil wells, the commenter (0808-API) states that EPA assumed that a flare would cost only \$5,700. The commenter suggests that this value significantly underrepresents actual costs experienced by operators. According to the commenter, a more representative cost for installing a flare suitable to control associated gas would be \$100,579, based on the average costs EPA uses for analyzing storage vessel controls. To obtain an average cost of \$100,579 per flare, the commenter reports that they reviewed the direct capital costs associated with calculation sheets issued by EPA.<sup>95</sup> [The comment letter includes a Table of the results of the Model Plant (MP) EPA Flares Calculation sheets MP1, MP2, MP-G and MP-H and Average.]

The commenter (0808-API) provides that they did not include the costs from EPA's Workbook "MP1 Plus Monitors.xlsx" because they believe that would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the November 2021 Proposal. The commenter notes that, if EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis.

Commenter (0425-Darrah) suggests that where emissions at sites are low, the impacts of flaring may outweigh the benefits.

Response I-17-30: See discussion in sections IV.H.2 and IV.H.3 of the December 2022 Supplemental Proposal.<sup>96</sup>

### ***17.11.2 Limitations on Beneficial Use by Public Service Commissions***

Comment: Commenter (0946-MOGA) recommends that EPA review each individual state's PSC regulations and provide individual cost analysis and feasibility analysis prior to imposing regulations designed to capture associated gas for useful purposes rather than flaring the gas. The commenter states that every oil and gas producer within the State of Michigan would gladly

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<sup>95</sup> <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0039>.

<sup>96</sup> 87 FR 74792 and 74795.

bring associated gas to market or provide for local landowners, farmers, businesses, homes, *etc.* that would otherwise be combusted. However, the commenter notes that strict rules and regulations regarding the ability to bring associated gas to market prevent oil and gas producers from directing gas to a useful purpose rather than flaring the gas. Until EPA provides a comprehensive feasibility analysis to understand each state's PSC regulations and limitations, the commenter believes EPA should avoid proposing technically infeasible restrictions on oil and gas producers.

Response I-17-31: EPA cannot respond to this comment because it is too general in nature and the EPA cannot agree or disagree without further information. EPA reviewed available online information regarding the sphere of activity for the Public Service Commission (PSC) in Michigan, but could not identify with certainty examples of regulations with a potential for conflict with the NSPS as described by the commenter.

## 17.12 Other

Comment: Commenter (0594-Huntsman Corporation) suggests that - when access to a sales line is infeasible – their technology (methane pyrolysis) is an ideal candidate to serve as a bridge. The commenter states that the use of methane pyrolysis can simultaneously consume the associated gas while generating clean fuel that emits no GHGs and a commercially viable product with unique strength and weight properties. According to the commenter, this is a prime example of one of the agency's proposed control options of "beneficially using the associated gas."

Commenter (0231-West Virginia Attorney General) states that requiring oil wells that produce associated gas to route to a sales line compels source owners and operators to engage in transactions beyond their facilities' fencelines, and Section 111 does not grant EPA power to require beyond-the-fenceline market measures. The commenter also states that routing to a sales line may not accomplish any emission reductions, as any gas sold will ultimately be combusted by any gas purchaser.

Response I-17-32: With respect to methane pyrolysis technology, see the response to I-17-28.

EPA disagrees with the comment that requiring an oil well to route associated gas to a sales line is a beyond the fenceline measure. The technology that routes associated gas (a "waste" product created by oil extraction<sup>97</sup>) is a control that is applied at the source (the oil well) that reduces emissions at the source. It is true that the pipeline that carries the gas away from the source may extend beyond the fenceline of the facility, but at the source controls commonly require off-site disposal of waste captured by the control. Capturing the associated gas occurs within the fenceline at the site. Putting the captured gas into a pipeline also occurs within the fenceline at the site. At some point that gas will transfer into a pipe that exists outside the fenceline of the site where the gas was extracted, but that fact does not negate the fact that the control technique itself (capture gas and put gas into pipeline) happens within the fenceline at the site. Even if routing to a sales line is considered a beyond the fenceline measure, it remains permissible under CAA

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<sup>97</sup> An owner/operator of a well that produces oil may consider associated gas to be waste because it is not the product which the operation intends to extract and sell. However, as EPA has explained in this rulemaking, the associated gas can be used and is therefore not waste to others.

Section 111. *See* EPA's Final Subpart Ba Rule discussing Section 111's requirements. 88 FR 80480 (November 17, 2023). Lastly, EPA disagrees with the commenter that routing to a sales line will not reduce emissions. As compared with venting, which releases uncombusted gas into the atmosphere, routing to a sales line still accomplishes emission reductions even taking into account the fact that the gas sold may later be combusted. Combusted gas has fewer methane emissions than uncombusted gas.

## **Chapter 18. Additional Emission Sources and Definitions**

### **18.1 Abandoned Wells**

Response I-18-1: In the November 2021 Proposal, EPA solicited comment and information on idled and unplugged wells due to the EPA's understanding and concern that these non-producing oil and natural gas wells are generally unmanned and many are in disrepair.

In the December 2022 Supplemental, EPA proposed that owners and operators of each well site or centralized production facility may stop the required fugitive emissions monitoring and repair for that site when the well site has been properly closed because in that event there should not be any equipment or other fugitive components onsite for monitoring. 87 FR 74736. EPA proposed this requirement as an important step in maintaining transparency for the responsible owner or operator and will also prevent well sites from becoming orphaned in the future. This would also help address concerns cited by many stakeholders regarding continuing emissions from orphaned wells and unplugged idled wells.

As stated in section X.A. of the final preamble, EPA is finalizing these well closure requirements under the fugitives monitoring requirements for actively producing wells. The final well closure requirements will prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair. See RTC Volume II Chapter 4, section 4.1.6 (Well Closure Requirements) for response to comments on the well closure plan associated with the fugitive monitoring requirements. See 40 CFR 60.5397b(l) of NSPS OOOOb and 40 CFR 60.5397c(l) of EG OOOOc for the final well closure requirements.

We may consider regulation through a future action, including in the next 8-year review of the NSPS. The comment summaries are provided below for reference but substantive responses are not provided because no emissions standards have been proposed for this emissions source.

#### ***18.1.1 Regulatory Support***

Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0781-National Tribal Air Association (NTAA), 0605-Muscogee (Creek) Nation, 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD), 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD)) express interest in the supplemental proposal. The commenters assert that there are a significant number of abandoned wells throughout Indian country, many of which are not plugged and emitting harmful pollutants. The commenters also state that there are a significant number of oil and natural gas pipelines traversing Indian country that undergo pigging and blowdown activities. Until EPA proposes and finalizes the supplemental proposal, these emissions sources will remain largely uncontrolled. The commenters are concerned about the unknown emissions coming from these sources.

Commenter (0957-Wyoming Coalition of Local Governments (WYCLG)) states that the solicitation of comments on the potential for establishing standards for abandoned and unplugged wells is not appropriately included within the November 2021 Proposal because it fails to provide an adequate description of the issues involved or terms or substance of a proposed rule. The commenter recommends that EPA's request for additional information on other sources of

emissions instead be its own separate rulemaking, starting with an “Advance Notice of Proposed Rulemaking” to obtain the necessary information.

Commenter (0957-WYCLG) states that the November 2021 Proposal fails to document the scope and quantity of emissions from plugged or non-operating wells.

### ***18.1.2 Number of Abandoned Wells in the U.S.***

Commenter (1390-FracTracker Alliance (FTA)) suggests that EPA’s estimate of approximately 3.4 million orphaned and abandoned wells in the U.S. is an underestimate. Based on some peer-reviewed estimates, there could be as many as 750,000<sup>1</sup> such wells in Pennsylvania alone, suggesting that the scale of the problem could be even greater.

Commenter (0734-American Thoracic Society (ATS)) states there is an urgent need for the Biden Administration to curb emissions from abandoned wells and minds and ban routine flaring. The commenter reports that recent work indicates that there are approximately 4,000,000 abandoned oil and gas wells throughout the U.S., with these sites increasing over time.<sup>2</sup> The commenter suggests that EPA may be underestimating the annual methane (CH<sub>4</sub>) emissions from these sites by 20 percent.<sup>3</sup>

Commenter (1426-Public Citizen) reports that there are 6,400 orphaned wells in Texas. The commenter provides an October 2021 analysis from Environmental Defense Fund (EDF) using EPA data. The commenter’s analysis of the Texas Railroad Commission (RRC) data showed that 1,600 of these wells had been abandoned for 20+ years.<sup>4</sup>

### ***18.1.3 Abandoned Wells Emissions Estimates***

Commenter (0831- American Exploration and Production Council (AXPC))) suggests that emissions from abandoned wells are overestimated due to inconsistencies in terminology and a lack of relevant studies. The commenter notes that there appears to be a lot of confusion over the terminology that is leading to misconceptions and misunderstandings. For example, “abandonment” refers to the proper process of removing a well or pipe from service. Wells can be permanently plugged and abandoned, or temporarily abandoned if re-entry is anticipated, however both cases in general speak to leaving the well in a regulatorily compliant, protective state. Whereas EPA’s definition of “abandoned” includes all wells that are no longer in production; however, these wells may or may not be plugged. These terms are also often conflated with references to “orphan” wells or “idled” wells. According to the commenter, these sort of inconsistencies in terminology have led to incorrect counts and estimations as they relate to concerns on the landscape. Similarly, the commenter notes that there have not been many studies looking at emissions from abandoned and unplugged wells, or from orphan wells, and

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<sup>1</sup> “Identification and characterization of high methane-emitting abandoned oil and gas wells.” Mary Kang, et al. <https://pubmed.ncbi.nlm.nih.gov/27849603/>.

<sup>2</sup> Williams, JP; Regehr, A & Kang, M. Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States. *Env. Sci Technol* 55, 570 (2021).

<sup>3</sup> Id.

<sup>4</sup> RRC, Orphan Wells with Delinquent P-5 Greater Than 12 Months, (Sept. 17, 2020, 9:09:12 AM) <https://rrc.texas.gov/oil-gas/researchand-statistics/well-information/orphan-wells-12-months/>.

what studies there are do not geographically represent the entire U.S. and/or were biased by the inclusion of noticeable outliers. For these reasons the commenter believes that emissions from abandoned wells are not as great as EPA suggests. The commenter reports that this type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the U.S. Greenhouse Gas Inventory (GHGI).

Commenter (0808-American Petroleum Institute (API)) states that emissions from non-producing oil and gas wells are comparatively small and may currently be overestimated within the datasets used by EPA's Inventories Program on Climate Change. Under EPA's current methodology, the emissions from non-producing oil and gas wells constitute approximately 3 percent of all methane emissions from the energy sector – a number similar to rice cultivation.<sup>5</sup>

The commenter (0808-API) notes that definitional challenges across state agencies and data sets can lead to apples-to-oranges comparisons. For example, the commenter states that the distinction between “abandoned” and “abandoned and plugged” is considerable. Beyond the Interstate Oil and Gas Compact Commission (IOGCC) definitions, the oil and gas industry often refer to any well that has been properly plugged as “abandoned and plugged.” Similar to industry, EPA's definition of “abandoned” includes all wells that are no longer in production; however, these wells may or may not be plugged, and may or may not be considered “orphan” as defined by IOGCC. The commenter states that this type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the U.S. GHGI.

In an attached letter<sup>6</sup> to the commenter's (0808-API) submission, dated November 16, 2021, to Ms. Melissa Weitz, the commenter recommended the following clarifications and revisions to EPA's proposed GHGI methodology,<sup>7</sup> all of which underscore the challenge of creating an accurate count of wells across data systems:

- Correcting assumptions concerning plugged vs. unplugged wells. The commenter requests that EPA provide a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, the commenter maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72 percent of the wells that would be classed as “abandoned” by the criteria in Table 3 of the 2022 memo are shown as actually “plugged and abandoned.”<sup>8</sup> Hence, the commenter asserts that EPA should not ignore the Enverus data in favor of unsupported assumptions.

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<sup>5</sup> GHGI United States Environmental Protection Agency, Global Greenhouse Gas Inventory (2019).

<sup>6</sup> Attachment D API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks, November 16, 2021.

<sup>7</sup> [https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells\\_sept-2021.pdf](https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf)  
2 IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies.

<sup>8</sup> The commenter's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to the commenter's analysis of current date Enverus well counts. The commenter requests that EPA validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

- Using the IOGCC Data. The commenter suggests that an alternative estimate of historically abandoned wells could be based on data for “undocumented orphan wells” provided in the 2019 report issued by IOGCC.<sup>9</sup> According to the IOGCC 2019 report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000.<sup>10</sup> Beyond the IOGCC information, the commenter is not aware of alternative, high quality sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories.
- Avoiding the double counting of dry wells. The commenter requests that EPA provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. The commenter notes that the designation of “Dry Wells” in the Enverus database indicate a production type rather than a status type and EPA’s approach of considering all wells with no cumulative production as abandoned wells is likely leading to double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA’s assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93 percent of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other state requirements are believed to be similar. Moving forward, the commenter recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus ‘Plugged and Abandoned’ (P&A) status for determining what dry holes are unplugged. The commenter further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells.

In the same attached letter,<sup>11</sup> the commenter (0808-API) also highlights some data considerations which may lead to an overestimation of emissions from those wells:

- Considering the impact of state regulations. Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. The commenter stipulates that the simple assignment of the ‘unplugged’ designation to all the status codes that are not ‘Excluded’ or “Plugged and Abandoned” (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive.
- Using geographically correct emission factors. The commenter commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. The commenter noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the “entire U.S.” emission factors from the Townsend-Small study, which include the much higher Eastern U.S. (Appalachian - Ohio) emission factors. They then use these same Eastern U.S. factors

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<sup>9</sup>[https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020\\_03\\_04\\_updated\\_idle\\_and\\_orphan\\_oil\\_and\\_gas\\_wells\\_report.pdf](https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_report.pdf) Updates Under Consideration – 2022 GHGI.

<sup>10</sup> Id. Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018).

<sup>11</sup> Attachment D API Comments on EPA’s Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks, November 21, 2021.

from Townsend-Small coupled with emissions from Kang 2016 to develop emission factors for Appalachian basin abandoned wells. The commenter recommends that EPA should use the more appropriate “western U.S.” emission factors for abandoned wells outside of the Appalachian basin.

- Treating outliers appropriately. Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hour that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. The commenter contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH<sub>4</sub> emissions from Abandoned Wells to the GHGI.

Similarly, the commenter (0808-API) states that it is important to note that other parts of the U.S. government are already considering the question of outliers or super-emitters. During a recent presentation to the Health Effects Institute, the commenter reports that Natalie Pekney from the Department of Energy’s (DOE) National Energy Technology Lab (NETL) presented research showing that a comparatively small number of super-emitter wells are increasing the average emission rate.<sup>12</sup> This estimate was based on NETL’s techniques for locating undocumented orphan wells by searching for magnetic signatures (using walking, helicopters, and drones) which have been validated through field work in Pennsylvania, Oklahoma, and Kentucky. The commenter suggests that EPA may benefit from looking at NETL’s work in more detail, particularly since NETL intends to undertake more work in this area in Kentucky, New York, and Texas over the next few years.<sup>13</sup> The commenter notes that this observation would be consistent with the states’ established practice of prioritizing plugging and abandonment for individual wells; consequently, they suggest that EPA may benefit from learning more about both NETL’s research and considering how it may already be applied at the individual state level.

#### ***18.1.4 Abandoned Well Definition***

Commenter (0599-Marcellus Shale Coalition (MSC)) believes that abandoned wells do not meet the definition of an affected source for a new source performance standard (NSPS).

Commenter (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK)) recommends that EPA not broadly characterize wells collectively as they are very different. The commenter states that EPA broadly characterizes abandoned wells as oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells such as idle, inactive, dormant, shut-in, and orphaned wells. The commenter explains that these wells, except for orphaned wells, typically have a responsible owner/operator but are not producing for a specific reason *e.g.*, product pricing, held by other production in the unit, or waiting on some specific activity like a workover. On the other hand, the commenter states that an orphaned well is a well

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<sup>12</sup> Slide 8.Dr. Natalie Pekney, presentation on Health Effects Institute’s webinar concerning “Abandoned and Orphaned Oil and Gas Wells,” November 30, 2021.

<sup>13</sup> *Id.*



where there is no responsible owner/operator *e.g.*, the owner/operator has gone bankrupt.

Commenter (0808-API) notes that the IOGCC report provides helpful clarification of terminology, which is often misused in idle/orphan well conversations. The commenter encourages EPA to align its terminology with the terminology used by IOGCC to reduce confusion:

- Idle Wells. The IOGCC defines idle wells as “wells that have not been plugged and are not producing, injecting, or otherwise being used for their intended purposes.”<sup>14</sup> Similarly, IOGCC notes that “[M]any idle wells have potential for oil or gas production or associated uses.”<sup>15</sup> The future outcome for an idled well could be that it is brought into production, plugged, or converted to an injection well for enhanced oil recovery or for disposal. Most regulatory agencies set a timeline and requirements (whether statutory, by rule, or by specific written approval) for how long a well may remain idled before it must be plugged. The total number of approved idle wells reported by the states as of December 31, 2020, is 231,287, which is 14 percent of the total number of documented wells that have been drilled but not plugged.<sup>16</sup> Notably, despite including 4 more states in the 2021 report, this is down over 20 percent from the IOGCC’s 2019 figures, which featured “a total number of approved idle wells is 294,743, which is 15.6 percent of the total number of documented wells that have been drilled and not plugged.”<sup>17</sup> In the three years covered by this report, operators plugged 62,463 wells in the states.<sup>18</sup>
- Orphan Wells. IOGCC defines orphan wells as “idle wells for which the operator is unknown or insolvent. Most states and provinces have inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. As of December 31, 2020, the states reported a total of 92,198 documented orphan wells, and the provinces reported a total of 5,015 documented orphan wells. In the states, the number of documented orphan wells increased by 50 percent from 2018 to 2020, due primarily to the efforts of states to document these wells through investigation and verification of the status of wells and their operators. In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300.”<sup>19</sup>
- Undocumented Wells. IOGCC identified undocumented wells as a category for further work, noting that these are mostly a historical concern. Unverified estimates “do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not constitute a significant risk to the environment or public health and safety.”<sup>20</sup> The commenter states it is important to understand that the lack of plugging documentation for these wells does not mean they were never plugged and the lack of the locations for such wells

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<sup>14</sup> IOGCC (2021) at 2.

<sup>15</sup> *Id.*

<sup>16</sup> *Id.*

<sup>17</sup> IOGCC (2019) at 5.

<sup>18</sup> IOGCC (2021) at 2.

<sup>19</sup> *Id.*

<sup>20</sup> *Id.* at 3.

make any action or quantifications difficult. Thanks to modern record-keeping and regulation it is uncommon to be unable to identify the owner or operator a well. The majority of orphaned or undocumented wells occur as a result of development before the 1950s. For example, Pennsylvania is estimated to have the largest number of orphaned wells in the country, and the Pennsylvania Department of Environmental Protection (DEP) explains, “Since the first commercial oil well was drilled in Pennsylvania in 1859, it is estimated that 300,000 oil and gas wells have been drilled in the state. Only since 1956 has Pennsylvania been permitting new drilling operations, and not until 1985 were oil and gas operators required to register old wells.”<sup>21</sup>

#### ***18.1.5 Abandoned Wells in the Context of Environmental Justice***

Commenter (0573-Kansas Department of Health and Environment (KDHE)) requests that EPA consider abandoned and unplugged wells in the context of environmental justice (EJ) communities adjacent to affected facilities and that EPA incentivize appropriate well closure.

Commenter (0781-NTAA) requests that EPA work with Indian Tribes, the Department of Interior (DOI) and other federal agencies to expeditiously address orphaned and abandoned wells within Indian country. The commenter states that, with proper funding and support, Tribes can partner with EPA and other agencies to reclaim abandoned wells within Indian Country. The commenter suggests that EPA should explore funding options from potential funding streams from infrastructure funding, including a partial set-aside for Tribes from the \$150 million in the Infrastructure Investment and Jobs Act set aside for plugging and remediating orphan wells on Tribal lands. EPA’s response to this request can be provided within the supplemental proposal.

Commenter (0586-Navajo Nation Environmental Protection Agency (Navajo EPA)) requests that EPA work with the Navajo Nation and other federal agencies to expeditiously address abandoned wells on the Navajo Nation.

Commenters (0391-KBIC, 0605-Muscogee (Creek) Nation, 0943-Sault EPD, 0833-Ute EPD) request that EPA work with Indian Tribes and other federal agencies to expeditiously address abandoned wells within Indian country.

#### ***18.1.6 Support for Regulation of Emissions from Abandoned Wells***

Several commenters (0326-Private Citizen, 0391-KBIC, 0401-Mercy Investment Services, Inc. (Mercy), 0414-Waterspirit, 0435-Wespath Benefits and Investments (Wespath), 0437-New York Office of the State Comptroller (NYOSC), 0573-KDHE, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0723-Ceres, 0753-Institute of Governance & Sustainable Development (IGSD) and Center for Human Rights and the Environment (CHRE), 0770-Northern Plains Resource Council (NPRC), 0781-NTAA, 0795-American Lung Association (ALN) *et al.*, 0796-Asthma and Allergy Foundation of America-Michigan Chapter (AAFA-MI) *et al.*, 0833-Ute EPD, 0842-

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<sup>21</sup> DEP Quote Pennsylvania Department of Environmental Protection, “The Well Plugging Program”, <https://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/AbandonedOrphanWells/WellPluggingProgram.pdf>.

Institute for Policy Integrity at NYU School of Law (NYU), 0844-Environmental Defense Fund (EDF) *et al.*, 0918-Colorado Local Government Coalition (COLGC), 0931-Essential Information, Inc. (Essential), 0943-Sault EPD, 1267-California Office of the Attorney General (CA AG) *et al.*, 1282-Earthworks, 1302-Wyoming Outdoor Council (WYOC) and the Powder River Basin Resource Council (PRBRC), 1330-Catskill Mountainkeeper, 1387-350 Bay Area Action (350 BAA), 1390-FTA) support EPA including requirements to reduce emissions from abandoned wells in the supplemental proposal. Some examples of specific comments provided are included in the following paragraphs.

Several commenters (0326-Private Citizen, 0401-Mercy, 0414-Waterspirit, 0435-Wespath, 0578-Grand Canyon Trust (GCT), 0753-IGSD/CHRE, 0795-ALN *et al.*, 0842-NYU, 0844-EDF *et al.*, 0918-COLGC, 0931-Essential, 1282-Earthworks, 1302-WYOC/PRBRC, 1330-Catskill Mountainkeeper, 1387-350 BAA) note the quantity of emissions and/or associated adverse health and climate impacts associated with methane and VOC emissions from abandoned wells as support for the need for regulation/mitigation of emissions.

Commenters ((0391-KBIC; 0586-Navajo EPA; 0605-Muscogee (Creek) Nation; 0781-NTAA; 0833-Ute EPD; 0943-Sault EPD) believe that EPA should also propose monitoring at abandoned and orphaned wellhead only well sites, which also release emissions.

Commenter (0918-COLGC) supports EPA's intention to issue a supplemental proposal in 2022 that will provide proposed regulations for additional sources of pollution of methane and VOC emissions from the oil and natural gas sector. The commenter notes that the EPA estimates that the U.S. population of abandoned wells (including orphaned wells and other non-producing wells) is around 3.4 million (with around 2.7 million abandoned oil wells and 0.6 million abandoned gas wells). EPA points out that wells that are plugged have much lower average emissions than wells that are unplugged (less than 1 kg CH<sub>4</sub> per well per year, versus over 100 kg CH<sub>4</sub> per well per year). Around 40 percent of the abandoned well population in the United States is plugged.

The commenter (0918-COLGC) notes that studies show idle and plugged wells can be super-emitters. A review of recent studies demonstrates an emerging consensus that inactive and plugged wells have the potential to emit methane. For this reason, the commenter supports the inclusion of abandoned and unplugged wells in EPA's upcoming supplemental proposal.

The commenter (0918-COLGC) reports that a 2016 study found that plugged and idle wells contributed 0.1 percent to 0.2 percent of methane emissions in the Denver-Julesburg Basin. It also concluded that methane samples from wells were from both natural gas and coalbed methane, indicating that there was a mechanism allowing for underlying coal formations to vent or leak methane into the wellbore. Another study found:

99% of emissions from plugged wells are attributable to the top 10% of emitters (super emitters), and. . . overall, the top 10% of emitters contribute to 96% of methane emissions from idle wells as a whole. Specifically, the 10 highest emitting wells with over 100 grams per hour of emissions contributed 65% of cumulative emissions from all studies.

Lastly, the commenter (0918-COLGC) states that the 2018 EPA GHG Inventory found that plugged wells emit less than 1 kilogram of methane per year, and that unplugged wells emit over 100 kilograms of methane per year. A 2020 study calculated an average emissions factor of 96 grams per day (equivalent to 4 grams per hour) for plugged wells, but found that this was skewed by a single plugged well that was leaking 1900 grams per day (79 grams per hour). The Colorado Oil and Gas Conservation Commission (COGCC) conducted a literature review in connection with their recent Financial Assurances rulemaking of multiple published, peer-reviewed and state-government scientific studies of methane emissions from idle, plugged, and active wells. These studies reflect that “super-emitter” wells have a significant impact on mean/median emissions values. Super-emitters are wells with a significant integrity issue or other problem that results in substantially higher emissions than other similarly situated wells. The commenter asserts that unplugged wells pose multiple risks to the environment, including methane and other harmful hydrocarbon leaks.

Commenter (0844-EDF *et al.*) appreciates EPA’s attention to this issue. The commenter is strongly in favor of EPA minimizing emissions from abandoned wells and urges EPA to explore various options to minimize emissions from abandoned wells. The commenter reports that abandoned wells that are improperly plugged or not plugged are a significant source of emissions and may pose a safety threat. EPA estimates there are 2.1 million unplugged and abandoned wells nationwide emitting methane into the atmosphere. EPA further estimates that these wells emitted 55,000 metric tons of methane in 2019 alone, and other studies suggest that the number may be much higher. The commenter notes that many wells are orphaned or owned by entities that cannot pay to properly plug them, leaving that task to states and taxpayers—and the price tag can be hefty. According to a 2010 Government Accountability Office (GAO) report, between 1988 and 2009, the Bureau of Land Management (BLM) reclaimed 295 orphaned wells and spent an average of \$12,788 per well, with costs ranging as high as \$582,829 for a single well.

Commenter (1302-WYOC/PRBRC) notes that according to estimates from the Wyoming Oil and Gas Conservation Commission, Wyoming has over 1,300 documented abandoned oil and gas wells on state or private lands alone.<sup>22</sup> This number is certainly an undercount of the true total found across all jurisdictions. Unfortunately, orphaned and abandoned wells can be significant emitters of methane and other harmful gasses as well as a public liability and hazard. In future rules, the commenter recommends that EPA structure regulatory requirements to ensure responsible maintenance and closure as well sites reach the end of their productive and economically viable lives.

Commenter (0578-GCT) recommends EPA require monitoring and plugging at abandoned and improperly plugged wells, not only will this create jobs within the oil and gas industry, it will also protect the health, safety, and environment of surrounding communities. The commenter notes that Colorado Plateau counties collectively are home to over 8,000 abandoned/orphan oil and gas wells. These wells often have no owner, and no party legally responsible for cleanup.

Commenter (0753-IGSD/CHRE) supports EPA’s intention to include abandoned and unplugged wells in the final rule. Because of their persistent emissions and interconnectivity with other oil and gas sources, they believe that abandoned and unplugged wells are properly regulated as a

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<sup>22</sup> Wyoming Oil and Gas Conservation Commission. Orphaned Well Site Plugging, Remediation, and Restoration.

source within the Crude Oil and Natural Gas source category under the Clean Air Act (CAA) section 111. To fulfil its CAA mandates, the commenter recommends that EPA propose and finalize regulations that protect communities from the harms caused by abandoned and unplugged wells and hold well owners accountable to the greatest extent possible. The commenter recommends that EPA promulgate stringent requirements for new and idled wells that can be quickly implemented to prevent tens of thousands (or more) wells from being abandoned and sitting unplugged for years. According to one study, “In the U.S. from 2000 to 2013, an average of 18,600 wells were abandoned per year....”<sup>23</sup> The U.S. GHGI found that abandoned gas wells (including orphaned and other non-producing wells) in the U.S. had increased by 84 percent from the 1990s, leading to a 38 percent increase in methane and carbon dioxide (CO<sub>2</sub>) emissions from abandoned gas wells.<sup>24</sup> In a recent release, the commenter reports that the Department of Interior counted more than 130,000 abandoned or orphaned wells—more than double the figure it had announced in 2019.<sup>25</sup> As EPA notes in the November 2021 Proposal, the GHGI estimates that around 3.4 million abandoned oil and gas wells were responsible for 264 kilotons (kt) of methane in 2019.<sup>26</sup> Substantial as those numbers are, the commenter suggests they are likely grossly underestimated.<sup>27</sup> Using geospatial and statistical analysis, a 2021 report concluded that the actual magnitude of methane emissions from abandoned oil and gas wells is likely 20 percent more than EPA estimates.<sup>28</sup> Experts also worry

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<sup>23</sup> Williams J.P., Regehr A., & Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, ENVIRON.SCI. & TECH. 55:563–570, 568 (“In the U.S. from 2000 to 2013, an average of 18,600 wells were abandoned per year, with a maximum of 35,500 in 2008 and a minimum of –4000 in 2009. The negative numbers of AOG wells drilled per year, represent a decrease in total AOG well numbers, and is likely a result of idle/inactive wells being re- entered into the production life cycle. Overall, the growing number of AOG wells implies that methane emissions from AOG wells are likely to be increasing.”).

<sup>24</sup> EPA (2021) U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990-2019, 3-111.

<sup>25</sup> Budryk Z. (5 January 2022), Interior: US has twice as many abandoned oil and gas wells as previously thought, THE HILL (“In a memo Wednesday, the department said there are currently more than 130,000 documented abandoned, or orphaned, wells. Comparatively, a 2019 report from the Interior documented a total of 56,600 orphaned wells across 30 states. Across the entire country they found that the number of abandoned wells in that report ranged from zero to 13,226.”).

<sup>26</sup> EPA (2021) U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990-2019, 3-111, tbl. 3-96 (2021).

<sup>27</sup> Williams J.P., Regehr A., & Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, ENVIRON. SCI. & TECH. 55:563–570, 568 (“Our estimates for annual methane emissions from AOG wells are consistently higher than those reported in the latest inventory report by 150%2 for Canada and by 20% for the U.S.1 The reasons for the larger degree of underestimation in the Canadian inventory are due to our use of a larger number of wells and higher emission factors. In contrast, the difference in the U.S. inventory is primarily due to our use of a larger number of wells. Nevertheless, emissions factors for the “entire U.S.” relied on data that were not distributed throughout the country but focused on western states, Wyoming, Utah, and Colorado and missing data from major oil- and gas-producing states such as Texas, Oklahoma, and California.”); Kang M., et al. (2021) Orphaned oil and gas well stimulus—Maximizing economic and environmental benefits, ELEMENTA 9:1–13, 3 (“According to state and provincial/territorial records, there are 4,653,000 historic and active oil and gas wells in the United States and another 788,000 in Canada (Tables S3 and S4). Of these, 1,954,000 (42%) and 313,000 (40%) wells are active in the United States and Canada, respectively. In the active well counts, we include wells drilled for enhanced recovery (e.g., injection wells) and disposal wells (e.g., saltwater disposal well that was formerly producing gas) in addition to those drilled to produce oil and gas. In the United States, 1,519,000 (33%) wells are plugged; while in Canada, 351,000 (45%) are plugged. Thus, two of three wells ever drilled in the United States are currently inactive, but only one in three are plugged (Tables S3 and S4).”)

<sup>28</sup> Williams J.P., Regehr A., & Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, ENVIRON. SCI. & TECH. 55:563–570, 569 (“Our estimates for annual methane emissions from AOG wells are consistently higher than those reported in the latest inventory report by 150%2 for Canada and

that the spate of oil and gas exploration and production companies that filed for bankruptcy or receivership in early 2020 may lead to an increase in abandoned wells.<sup>29</sup>

Commenter (0414-Waterspirit) asserts that indirect, direct, and cumulative emissions need to be considered.

Commenter (0723-Ceres) urges EPA to ensure strong methane emission performance standards by crafting a regulation that ensures abandoned wells are properly plugged at the end of their productive lives and do not leak methane in perpetuity.

Commenter (0326-Private Citizen) states that EPA must include many omitted methane sources in this proposal to ensure that the improvements due to increased monitoring are not offset by exemption loopholes and non-comprehensive oversight.

Commenters (0391-KBIC, 0781-NTAA, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0943-Sault EPD, 0833-Ute EPD) support: (1) the proper closure of abandoned oil and natural gas wells and restoration of the well site; (2) periodic inspection, and (3) monitoring of abandoned wells capable of emitting. The commenters also support requirements for owners/operators to submit a closure plan describing how the well would be closed and financial assurance or bonding to assure compliance with closure requirements.

Commenter (0573-KDHE) requests that EPA consider a program for capping abandoned wells to ensure those wells are properly closed and not leaking.

Commenter (0437-NYOSC) recommends that EPA develop a comprehensive policy that achieves significant emission reductions throughout the natural gas value chain and addresses emissions from the full complement of oil and gas production wells, including older, lower-producing wells and inactive or abandoned wells.

Commenter (1267-CA AG *et al.*) supports EPA's adoption of new source performance standards and emission guidelines that require fugitive emissions monitoring of idled and unplugged wells.

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by 20% for the U.S.<sup>1</sup> The reasons for the larger degree of underestimation in the Canadian inventory are due to our use of a larger number of wells and higher emission factors. In contrast, the difference in the U.S. inventory is primarily due to our use of a larger number of wells. Nevertheless, emissions factors for the "entire U.S." relied on data that were not distributed throughout the country but focused on western states, Wyoming, Utah, and Colorado and missing data from major oil- and gas-producing states such as Texas, Oklahoma, and California.").

<sup>29</sup> E.g. Kang M., et al. (2021) Orphaned oil and gas well stimulus—Maximizing economic and environmental benefits, *ELEMENTA* 9:1–13, 2 ("In the first half of 2020, 30 oil and gas exploration and production companies filed for bankruptcy or receivership in the United States and Canada (Tables S1 and S2). Across the United States and Canada, these companies operate 116,245 wells in 32 states and four Canadian provinces/territories, with the most in California (37,620), Texas (16,529), and Oklahoma (12,258; Figure 2). Wells operated by companies going bankrupt are not necessarily orphaned but may change ownership or continue to produce within the restructured company (Schuwerk and Rogers, 2020). In some cases, wells change hands multiple times before being abandoned. As a result, available data cannot yet be used to understand precisely how many of the wells operated by bankrupt companies are being, or will be, orphaned across the United States and at what timescale (Figure S2). Nevertheless, data from Alberta show that a drop in oil price leads to an increase in the number of orphaned wells in the following approximately 3 years (Figure S3).")

Commenter (0770-NPRC) urges EPA to establish new standards to ensure oil and gas wells are properly shut down and plugged, to prevent them from leaking in perpetuity and to prevent closure costs from falling to taxpayers later. The commenter states that EPA has an obligation to strengthen its November 2021 Proposal and advance rules that leave no loopholes nor future opportunities for methane pollution from oil and gas infrastructure. The commenter notes that, as one testifier at EPA’s December public hearing noted, “[w]e have learned that most oil and gas operators only respond to that which is required by rule or law.”

Commenter (1390-FTA) recommends that locating and plugging should be approached with the utmost sense of urgency. Currently, the commenter suggests there exists a disincentive for states to locate and plug such wells, as they become the responsible party in the absence of a viable operator. They add that this perhaps explains why the official list of orphaned and abandoned wells in Pennsylvania is only 8,959 wells,<sup>30</sup> or about 1.2 percent of the estimated total of these wells. DEP has only been able to find resources to plug just a handful of wells<sup>31</sup> in recent years – to plug the full inventory would take millennia at this rate. Pennsylvania is shown as an example here; the commenter is aware that other oil and gas producing states find themselves in a similar predicament. It is the commenter’s opinion that those who seek to exacerbate the methane pollution crisis by drilling new wells should pay for the locating and plugging of wells. And yet, they believe that models based on permit fees can never suffice without drilling hundreds of thousands of new wells, thereby making the methane crisis all that much worse.

Commenter (1267-CA AG *et al.*) supports and strongly encourages EPA to address emissions from abandoned wells at the federal level through NSPS and EGs. The commenter supports EPA’s adoption of NSPS and EGs that establish uniform federal requirements to minimize or eliminate emissions from abandoned wells, including by establishing as the Best System of Emission Reduction (BSER) work practice or operational standards designed to prevent wells from becoming improperly abandoned in the first instance. The longer wells are allowed to remain idle, the greater the potential for them to deteriorate and leak or become orphan wells. Thus, the NSPS and EGs should limit as the BSER the time that operators are allowed to idle wells and require strict management plans for idled wells to ensure that wells are properly plugged and do not become orphan wells.

Commenter (0842-NYU) recommends that EPA propose supplemental standards to cover abandoned wells, flares, and other equipment within the oil and gas source category. Given the broad definition of the source category, and this additional equipment’s large contribution to methane emissions, the commenter recommends that EPA issue any additional standards that the agency determines are cost-benefit justified. The commenter believes that EPA should regulate these additional sources to the extent that doing so will increase net benefits for society. The commenter notes that additional sources undoubtedly fit within the oil and gas source category, as EPA has already concluded that the category is broad enough to include any equipment that is

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<sup>30</sup> Pennsylvania Department of Environmental Protection Abandoned and Orphaned Well Report. [http://cedatareporting.pa.gov/Reportserver/Pages/ReportViewer.aspx?/Public/DEP/OG/SSRS/Abandoned\\_Orphan\\_Web](http://cedatareporting.pa.gov/Reportserver/Pages/ReportViewer.aspx?/Public/DEP/OG/SSRS/Abandoned_Orphan_Web).

<sup>31</sup> “DEP Well Plugging Program.” Pennsylvania DEP. <https://www.dep.pa.gov/Business/Energy/OilandGasPrograms/OilandGasMgmt/LegacyWells/Pages/Well-Plugging-Program.aspx>.

part of the sequence of functions that are interrelated and necessary for getting distributed gas ready for distribution. Furthermore, the commenter states that the benefits of regulating these additional sources standards are likely substantial, as EPA recognizes that abandoned and unplugged wells, flares, pipeline pigging operations, and tank truck loading operations generate significant methane emissions. Abandoned and idled wells have a particularly strong need for federal regulation given that such idling is frequently the result of market failures due to owner/operator bankruptcy with insufficient bonding or market conditions making continued production unprofitable.

Commenter (0842-NYU) contends that proposing supplemental standards for these sources would better fulfill EPA's statutory mandate to determine the best overall system of emission reduction for the source category, as well as with President Biden's recent memorandum reaffirming the principles of Executive Orders 12,866 and 13,563—including that agencies should select regulatory alternatives that “maximize net benefits” while also accounting for distributive impacts and equity. Accordingly, the commenter recommends that EPA fully evaluate the costs and benefits to controlling emissions from these additional sources and propose supplemental standards to the extent that such controls are net beneficial.

Commenter (0326-Private Citizen) recommends that EPA propose a jobs program to plug abandoned oil wells. The commenter suggests that one of the largest emitters of methane originates from unproductive oil wells. Leakage from abandoned oil and gas wells was estimated to be the third largest source of emissions in the industry by the Agency yet the November 2021 Proposal sets no requirements for plugging the 2.1 million inactive wells across the country. These numbers, according to the commenter, are likely to grow as oil production declines with the pandemic and as we move to cleaner sources of energy in the coming years, are already unmanageable by state budgets or current manpower. For this reason, the commenter notes that emerging methane mitigation objectives must be understood as job-creating opportunities. Some local governments abroad have already implemented well-plugging programs. Last spring, the government of Alberta in Canada financed a non-profit organization initiative to plug 1000 wells in the province, thereby creating 500 direct or indirect jobs. Given the scale of the abandoned wells problem in the U.S. however, the efficiency of a jobs program would require a better definition of abandoned wells. The commenter notes that EPA's November 2021 Proposal provides a broad definition of abandoned wells: “a wide range of non-producing wells (...) includes wells that state governments classify as idle, inactive, dormant, or shut-in, but not plugged.” This category mixes new, deeper, shale wells which would be more expensive to plug with wells abandoned since the 19th century. It also mixes inactive wells with known owners to “orphaned” sites. Since the plugging cost will likely vary according to the well's age and will be distributed differently depending on ownership, the commenter recommends that EPA provide a more precise definition of abandoned wells to allow more accurate impact analyses for future rulemaking.

The commenter (0326-Private Citizen) states that a well-plugging program's feasibility is also dependent on identifying an attainable target of leaking inactive wells. Fortunately, the reality is that not all wells are high emitters: one study found that only 16 percent of leaks account for 98 percent of methane emissions from idle wells. To focus efforts on high emitters, the first step is to incentivize the deployment of nationwide measurements of methane from abandoned wells.



This would provide more data on the number and location of wells to target as well as the volume of emissions that can be mitigated. The commenter recommends that EPA create a carbon offset program which attributes carbon credits to well-plugging projects according to methane leakage levels. This market-based incentive would require participating companies, non-profit organizations, and researchers to measure methane leaks and thus increase investments in technology to scale up leakage monitoring.

Commenter (0795-ALN *et al.*) provides that studies have found high rates of methane leakage from abandoned wells. For example, a study of inactive wells in Pennsylvania estimated the number of abandoned wells in that state to be between 470,000 and 750,000, significantly higher than previous estimates. The study estimated that, overall, Pennsylvania's abandoned wells contributed between five and eight percent of the state's annual greenhouse gas emissions.<sup>32</sup> A study of abandoned oil and gas wells in California found 124,000 abandoned wells. Based on measurements from a representative sampling of those wells, the study found that those with the highest leakage rates released enough methane to substantially impact the state's methane budget.<sup>33</sup>

Commenter (0795-ALN *et al.*) notes that methane leakage from abandoned wells varies widely, with a few high emitters responsible for a disproportionately large share of the problem. A 2020 study by a research team from McGill University in Canada collected and analyzed data on methane emissions from almost 600 abandoned wells in the United States and Canada, then extrapolated a cumulative total. The research team concluded that 96 percent of cumulative emissions came from 10 percent of wells, with unplugged abandoned gas wells being the highest emitters. While noting uncertainty about the actual quantity of these emissions, given that few abandoned oil and gas wells have been measured for leakage, the study indicated that for the U.S., methane emissions from abandoned wells were 20 percent higher than previously estimated.

Commenter (0795-ALN *et al.*) states that there are currently no federal regulations to require monitoring methane emissions from inactive and abandoned wells, although some states have their own requirements. Nor does the federal government currently govern the remediation of orphaned wells.<sup>34</sup> The commenter explains that states require oil and gas companies to put up bonds for well plugging prior to the onset of drilling, but the amounts of these bonds often fall dramatically short of the costs. In many cases, according to a California news report, "companies have no incentive to spend more money, and essentially walk away, leaving the responsibility and costs to state and federal governments."<sup>35</sup> The commenter notes that, as a consequence, as a

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<sup>32</sup> Kang, M., Christian, S., Celia, M. A., Mauzerall, D. L., Bill, M., Miller, A. R., Jackson, R. B. 2016. Identification and characterization of high methane-emitting abandoned oil and gas wells. *Proceedings of the National Academy of Sciences*, 113(48), 13636-13641. doi: 10.1073/pnas.1605913113.

<sup>33</sup> Lebel, E.D., Lu, H.S., Vielstädte, L., Kang, M., Banner, P., . . . Jackson, R.B. (2020). Methane emissions from abandoned oil and gas wells in California. *Environmental Science & Technology*, 54(24), 14617-14626. doi: 10.1021/acs.est.0c05279.

<sup>34</sup> Steven Nelson and Jonathan M. Fisk, "End of the (Pipe)Line? Understanding How States Manage the Risks of Oil and Gas Wells," *Review of Policy Research* 38, no. 2 (2021): 203–21, <https://doi.org/10.1111/ropr.12411>.

<sup>35</sup> Mark Olander, "Oil Bankruptcies Leave Environmental Cleanup Bills to California Taxpayers," *Desert Sun*, June 25, 2021, <https://www.desertsun.com/in-depth/news/environment/2021/06/25/oil-bankruptcies-leave-environment-cleanup-california-taxpayers/4977647001/>.

journal article noted, “Government agencies responsible for well plugging often face funding shortfalls and many orphaned wells remain unplugged.”<sup>36</sup>

Furthermore, the commenter (0795-ALN *et al.*) believes that oil and gas well owners should be held responsible for the prompt cleanup of their wells, and action should be taken promptly, as the risk of methane leaks increases as inactive wells age. The commenter asserts that strengthening monitoring requirements to require all wells to be subject to frequent leak detection and repair inspections, prohibiting the routine flaring of associated gas at oil and gas sites, engaging frontline communities and other observers in documenting pollution and emissions and addressing methane’s climate impact utilizing the all-important 20-year timeframe would strengthen EPA’s efforts to protect us from climate change and would convey immediate health benefits by reducing air pollution.

Commenter (0940-Responsible Drilling Alliance (RDA)) asks EPA to carefully consider the written comments of companies engaged in emission detection and mitigation, such as the one submitted by Smith Analytical. According to the commenter, Smith claims its methane/VOC mitigation system is far more cost effective than well plugging and can also be used for emissions from problematic equipment in active wells to eliminate methane, VOC, and hazardous air pollution (HAP) emissions with 99 percent effectiveness. The commenter urges EPA to test and consider such methods.

Commenter (0931-Essential) states that the 2021 GHGI estimates that in 2019 there were around 3.4 million abandoned wells (including orphaned wells and other non-producing wells). Of these, 2.7 million are abandoned oil wells and 0.6 million are natural gas. These non-producing wells often have significant and damaging methane, CO<sub>2</sub>, and VOC emissions. The GHGI estimates that abandoned oil wells emitted 209 kt of methane and 4 kt of CO<sub>2</sub> in 2019, while abandoned gas wells emitted 55 kt of methane and 2 kt of CO<sub>2</sub> in that year.

Commenter (1390-FTA) is concerned that the mechanism of having the various states act as the means of enforcement of the regulations puts the efficacy of the entire guidance in question. The commenter advises adding provisions to hold the states themselves accountable, so that the numerous shortcomings of co-regulation are not repeated. The commenter notes one glaring example of this failed co-regulation dynamic is the Underground Injection Control (UIC) program, which regulates fluid subterranean fluid injections. EPA has shared authority and responsibility with the various states in a patchwork system of primacy.<sup>37</sup> Based on the language of the November 2021 Proposal, the commenter is concerned that the mechanism for regulating methane emissions by sharing responsibility with the states from oil and gas sources will follow down this same foreboding path. The results of this model have been disastrous. In some states, UIC wells are permitted to in such quantities and permitted to inject in such volumes that

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<sup>36</sup> Mary Kang et al., “Orphaned Oil and Gas Well Stimulus—Maximizing Economic and Environmental Benefits,” *Elementa: Science of the Anthropocene* 9, no. 1 (2021), <https://doi.org/10.1525/elementa.2020.20.00161>.

<sup>37</sup> “Primary Enforcement Authority for the Underground Injection Control Program.” Environmental Protection Agency. <https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program>.

widespread seismic activity has become commonplace. In others, affected neighbors dealing with ongoing health or environmental degradation must deal with both agencies, both of which frequently seem eager to claim that they are not responsible for overseeing the issue at hand. The system outlined in the proposed regulations seem like they could be designed in a similar way, with EPA providing emissions guidance to the various states, leaving enforcement up to them. As with the UIC program, any ambiguity with respect to which agency is in charge is likely to lead to inconsistencies, data gaps, and overall poor regulation. The commenter thinks that if EPA wishes to pursue a joint regulation with the states that they should do so with extreme caution, and that the various states must be held accountable for upholding their delegated authority. Without such enforcement mechanisms in place, the proposed rules are likely to be far less effective, and damaging emissions would therefore likely continue in a nearly unimpeded fashion.

#### ***18.1.7 Implications of Exempting Wells from Monitoring Under Fugitives Monitoring Requirements***

Commenter (0578-GCT) notes that EPA's recommendation not to monitor oil and gas wells that produce under 3 tons per year (tpy) of emissions each year leads to exempting declining sites such as abandoned oil and gas wells, as many of these wells produce less than 3 tpy per year of methane emissions.<sup>38</sup> The commenter reports that abandoned wells contribute a significant amount of emissions to the atmosphere. Like active wells, they emit methane and VOCs and HAPs which are known to harm human health. There are also documented incidents where methane from abandoned wells has made its way into nearby homes causing explosions.

Commenter (1390-FTA) states that major gaps remain in the November 2021 Proposal. The regulations appear to fully allow methane emissions at any well site that does not exceed 3 tpy. One problem with this is the very high number of oil and gas wells that are orphaned and abandoned that exist in unverified locations, which cannot be effectively regulated if they cannot be found.

Commenter (0844-EDF *et al.*) asserts that the November 2021 proposed exemption from regular monitoring for sites below 3 tpy is problematic for end-of-life well issues. Exempting these sites from federal regulatory standards enables strategic asset transfers that perpetuate the cycle of improper abandonment and orphaning.<sup>39</sup> When smaller and declining sites are exempt from standards that apply to all other wells, it creates a perverse incentive to keep those wells in production for far longer than if the true costs were internalized. It also allows operators to forgo upkeep and maintenance required by methane regulations, creating high-emitting and dangerous site conditions. With no federal regulatory oversight and highly inconsistent state oversight,<sup>40</sup> operators often keep wells open beyond when they otherwise might in order to avoid the cost of plugging; many such wells would likely not be profitable if they were obligated to internalize

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<sup>38</sup> Data from the 2018 Greenhouse Gas Emissions Inventory for the Colorado Plateau.

<sup>39</sup> Zachary R. Mider and Rachel Adams-Heard, An Empire of Dying Wells, Bloomberg (Oct. 2021), <https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/>.

<sup>40</sup> Ho et al., Managing Environmental Liability: An Evaluation of Bonding Requirements for Oil and Gas Wells in the United States, 52 Env. Sci. Tech. 3908 (2018), <https://pubs.acs.org/doi/10.1021/acs.est.7b06609>.

plugging costs. Many of these companies go bankrupt, leaving taxpayers holding the bag.<sup>41</sup> Exemptions for these sites allow operators to avoid yet another cost and disincentivize proper closure.

The commenter (0844-EDF *et al.*) uses the following definitions:

*An abandoned well* is a well that is not producing, and that the operator does not presently intend to return to production.

*An orphan well* is an abandoned well where the operator or owner is insolvent or unknown.

*A plugged well* is a well that is no longer in production and has been plugged.

*A shut-in well* is a well where the valves have been closed so it is not producing.

*A wellhead only* is a well where all equipment has been removed other than the Christmas tree piping.

Under CAA section 111, the commenter (0844-EDF *et al.*) states that EPA may define “affected facilities” in various ways and set the parameters that a source must meet to qualify as an affected facility.<sup>42</sup> For example, EPA has allowed operators to remove all major production and processing equipment from a well site to become a “wellhead only” site, which is not an affected facility for purposes of fugitive monitoring.<sup>43</sup> The commenter recommends that EPA clarify in the well site affected facility definitions that any well which has not been properly plugged with cement according to the applicable state or federal standards is still an affected facility subject to leak detection and repair (LDAR) and any other applicable standards.<sup>44</sup> This would incentivize proper closure because it would provide an off-ramp from affected facility status, allowing operators to avoid incurring compliance costs that would otherwise be mandatory. Operators of shut-in or abandoned wells would thus be forced to choose between compliance costs and plugging, rather than remaining in a potential gray area and doing neither.

The commenter (0844-EDF *et al.*) notes that the wellhead only exemption from LDAR is another potential barrier to this approach because many idle or abandoned wells will satisfy this definition and have little incentive to plug. The commenter recommends that EPA could resolve this problem easily by eliminating the wellhead only exemption. If EPA retains that exemption, it will have to otherwise address this issue, potentially by setting time limits on the applicability of the exemption or requiring reporting on the status of these wells.

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<sup>41</sup> Alex Wolf, Bankruptcies Fueling Environmental Crisis at Abandoned Oil Wells, Bloomberg Law (Sept. 2, 2021), <https://news.bloomberglaw.com/bankruptcy-law/bankruptcies-fueling-environmental-crisis-at-abandoned-oilwells> (“More than 260 domestic oil producers filed Chapter 11 over a six-year period . . . . Many distressed fossil fuel companies are passing environmental obligations on to government bodies . . .”).

<sup>42</sup> See 42 U.S. Code § 7411(a).

<sup>43</sup> 40 CFR § 60.5430a.

<sup>44</sup> EPA might consider a variance from this requirement for orphaned wells that are already on a list to be plugged.

Commenter (1267-CA AG *et al.*) notes that, according to EPA, most idled and non-producing wells would be classified as wellhead only, which EPA is proposing to exclude from LDAR requirements. The commenter recommends that any idled “wellhead only” well should no longer be exempt from LDAR requirements given the risks associated with allowing wells to remain idled for long periods and to incentivize owners and operators to either produce or plug wells. The commenter recommends that EPA consider removing the “wellhead only” exemption entirely. Although “wellhead only” well sites have less ancillary equipment and therefore fewer fugitive emissions components, the wellhead itself does have emissions and should be inspected for leaks.<sup>45</sup> The commenter states that California’s regulation requires quarterly monitoring of “wellhead only” well sites,<sup>46</sup> which demonstrates feasibility of these requirements.

### ***18.1.8 Specific Abandoned Well Requirement Recommendations***

Several comments (1270-League of Women Voters of the United States (LWVUS), 0756-Baker Hughes, 0795-ALN *et al.*, 0828-Union of Concerned Scientists (UCS), 0918-COLGC, 0931-Essential) were received that provided specific recommendations for approaches to regulating/mitigating emissions from abandoned wells.

#### **18.1.8.1 Well Closure/Plugging Requirements**

Comment: Commenter (0931-Essential) recommends that EPA require owners to plug wells and restore well site for any well that is non-producing for four years that is producing methane emissions or VOC emissions of 1 tpy or more. The commenter explains that this four-year window gives owners adequate time to take a well temporarily out of production, and to decide whether they will invest more to seek to increase production, or to close up a well site. The commenter suggests that having an emissions guideline threshold should also put it within the purview of these rules.

Commenter (0756-Baker Hughes) recommends properly isolating zone(s) with flow potential deeper in the well before closing the well to the atmosphere near the surface. The commenter explains that, if only closing to the atmosphere (and not deeper in the well) there will be a risk of future leakage over time when corrosion compromises the casing integrity and formation near the surface cannot contain the well pressures from below.

The commenter (1270-LWVUS) explains that gas wells that are no longer in use can leak significant amounts of methane, along with aromatic hydrocarbons and water contaminated with toxic compounds-- either added during hydraulic fracturing or dissolved from deep in the earth. EPA studies,<sup>47</sup> as well as many others, have shown that unplugged or inadequately plugged wells

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<sup>45</sup> Emissions from Oil and Gas Production Facilities, TCEQ Contract 582-7-84003, Prepared by Eastern Research Group, Inc., Aug. 31, 2007, available at [https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/582078400\\_3FY0701-20090831-erg-i-ei\\_from\\_old\\_gas\\_facilities.pdf](https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/582078400_3FY0701-20090831-erg-i-ei_from_old_gas_facilities.pdf). Wellhead emissions were estimated using emission factors, wellhead counts, and production data.

<sup>46</sup> See Cal. Code Regs. tit. 17, § 95669.

<sup>47</sup> Table 3-101 in <https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-maintext.pdf?VersionId=yu89kg1O2qP754CdR8Qmyn4RRWc5iodZ>.

are a major source of methane emissions. A 2021 analysis by Reuters<sup>48</sup> indicated that in 2018 there were more than 3.2 million abandoned wells in the U.S. that emitted a total of 281 kilotons of methane that year. This was estimated to have the same global warming potential as the amount of oil used in one day in our country. This problem will grow significantly in the near future as many wells drilled in the past decade become insufficiently productive to be economically sustainable.

The commenter (1270-LWVUS) states that cement plugs are currently considered to be the best solution to stopping the leaks. A program to locate wells that are not plugged or improperly plugged, and ensure that they are appropriately capped- off, is necessary. Follow-up measurements will be needed on newly plugged wells because there are many factors that can interfere with formation of a strong, stable cement barrier. The cement must adhere firmly to the top of the wellhead and must also be free of contaminants such as drilling mud that could lead to the formation of leaks within a few years.<sup>49</sup>

The commenter (1270-LWVUS) adds that efforts to ensure that all wells remain properly plugged must continue on a long-term basis, because the cement plugs used on the wells have limited lifetimes, even when they are made using the best current practices. In general, cement plugs undergo environmental degradation resulting in a half-life of approximately 50 years. However, leakage may continue for many decades, or even centuries.<sup>50</sup>

Commenter (1270-LWVUS) states that since about 2015 there has been a steady increase in the use of longer laterals in horizontal drilling. This has led to significant increases in the flow of natural gas or oil. These increases lead to the use of more fracking fluid under higher pressure and thus these wells cost much more to plug.

Commenter (0756-Baker Hughes) provides details on proper well plugging. The commenter notes that requirements to properly plug wells vary across the world; nevertheless, there is broad industry understanding that wells are best sealed by "restoring the caprock."<sup>51</sup> This means placing a permanent barrier across the wellbore - effectively sealing all annuli and inside of the well - above a zone with flow potential. The caprock is a sealing formation, impermeable and with adequate strength to contain future pressures. The barrier material needs to be selected with permanence in mind, suitable for sealing in the specific wellbore environment. Barrier verification confirming the successful placement and isolation from the zone with flow potential is required. It is common to place a primary and secondary barrier above the zone(s) with flow potential.

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<sup>48</sup> <https://www.reuters.com/article/us-usa-drilling-abandoned-specialreport/special-report-millions-of-abandoned-oilwells-are-leaking-methane-a-climate-menace-idUSKBN23N1NL>.

<sup>49</sup> A Review of Past, Present, and Future Technologies for Permanent Plugging and Abandonment of Wellbores and Restoration of Subsurface Geologic Barriers <https://www.liebertpub.com/doi/10.1089/ees.2019.0333>.

<sup>50</sup> *Ib.*

<sup>51</sup> See API Recommended Practice (RP) 65-3, 1st Edition, Wellbore Plugging and Abandonment.

#### 18.1.8.2 Monitoring of Inactive and Abandoned Wells

Commenter (0918-COLGC) recommends that EPA issue a supplemental proposal requiring quarterly inspections of idle (*i.e.*, inactive, or temporarily abandoned), and annual inspections of plugged wells to detect and repair leaks.

To address leaks, and in particular super emitters, from idle and plugged wells, the commenter recommends the following:

- (1) Quarterly inspections of idle wells using optical gas imaging equipment or other technology capable of detecting surface leaks from idle wells; and
- (2) Annual inspections for plugged wells.

The commenter (0918-COLGC) notes that these recommendations reflect that properly plugged wells should not leak, and thus do not need to be inspected as frequently as idle wells. The commenter asserts that a quarterly inspection requirement for idle wells is consistent with EPA's November 2021 Proposal for producing wells, and since idle wells can be put back into production at any time and may or may not be subject to state requirements that can minimize the likelihood of leaks such as state inspection requirements, the commenter believes a quarterly inspection requirement is appropriate.

Commenter (0828-UCS) recommends, at a minimum, that EPA require periodic monitoring to identify potential leaks, and to ensure that there is a comprehensive well closure plan in place such that the nation's orphaned and abandoned well crisis gets no worse. The commenter states that for too long, the oil and gas industry has been allowed to abandon wells with impunity, repeatedly offloading the responsibility of well closure onto the general public at towering economic, health, and environmental costs. The commenter asserts that, while the country is now advancing efforts to remediate existing orphaned wells and multiple jurisdictions have or are revising some of the contributing factors that enabled such widespread abandonment, the fact is the threat of continued abandonments remains, and given their ongoing methane leakage, EPA has a responsibility to ensure standards reach this class of existing sources.

Commenter (0795-ALN *et al.*) encourages EPA to require that abandoned wells be monitored for methane leaks and, if found leaking, that they be plugged. Abandoned oil and gas wells – those that are not productive and have not been properly plugged – are among the high-volume methane emitters. The commenter adds that “orphaned” wells, which are abandoned wells whose owners are bankrupt or cannot be found, are also high-volume methane emitters.

Commenters (0757-Private Equity Stakeholder Project (PESP), 1282-Earthworks) argue that EPA must require monitoring and plugging of abandoned wells that are leaking methane. The commenter states that, according to a Reuters investigation, which conducted a comprehensive review of all available data in 2020, orphaned and abandoned wells in the United States were collectively responsible for emitting 281,000 tons of methane into the atmosphere in 2018. While orphaned wells no longer have an identifiable owner, abandoned wells are typically defined as an unproductive well with a known owner/operator. The commenters recommend that EPA require

twice-a-year monitoring at idle and unplugged wells, while also including a requirement for companies to submit comprehensive well closure plans in order to properly cap wells at their end of life.

#### 18.1.8.3 Bonding Requirements

Commenter (0931-Essential) recommends that EPA mandate bonding requirements for each new oil and gas well, of an amount sufficient to cover periodic monitoring, the full future costs of plugging and dismantling an oil or gas well, and complete restoration of the well site. The recommendation is in response to environmental concerns. The commenter notes that EPA recognizes that orphaned and abandoned oil and gas wells represent a major environmental problem. Furthermore, according to EPA data, “bonding requirements represent only a fraction of the actual costs to plug the well and restore the well site.”

#### 18.1.8.4 Liability for Costs of Plugging Wells

Commenter (0734-ATS) recommends that in a future version of this rule or in a separate rulemaking that EPA outline steps to ensure that companies are liable for the costs of plugging new and existing wells and mines. The commenter asserts that these protections must be built into the cost of new projects, and regulatory approvals should not proceed without clear allocation of funds for this purpose. The commenter recommends that future regulations and legislation outline mechanisms for industrial responsibility that curbs the ongoing proliferation of these polluting and dangerous sites across the country.

Commenter (0753-IGSD/CHRE) encourages EPA to use its broad authority under CAA section 111 to expand liability for original or other past owners and operators,<sup>52</sup> particularly where the transfer of unproductive wells to new ownership may have contributed to the ultimate improper abandonment of wells without regard to environmental risks, leading eventually to their orphaning. This rulemaking could also serve as an opportunity for EPA to discourage and reduce the unnecessary protracted maintenance of idled wells to avoid closure responsibility and costs. In addition, the commenter suggests that EPA should consider establishing new source performance standards and presumptive standards for abandoned wells that include expanded liability for past owners or operators. The absence of identifiable, liable parties for millions of orphaned wells is an underlying reality that demonstrates the need for EPA to help the sector ensure accountability of operators. The commenter suggests that EPA could use its broad authority under CAA section 111 to develop standards that would hold previous owners and operators accountable for cleanup and ensure orphaned wells are adequately addressed and properly plugged. For example, the commenter notes that, under California law, if the current operator goes bankrupt or does not have the funds to plug a well, the state can require a prior operator to plug the well.<sup>53</sup> EPA also can look to the successful Superfund program promulgated under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as a potential model for accountability mechanisms.

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<sup>52</sup> See generally Rotblat C. (2017) Caring for the Orphans: Approaches for Mitigating Fugitive Methane Emissions from Orphaned Oil and Gas Wells, ENVIRON. L. REP. NEWS & ANALYSIS 47:10529–10541, 10535.

<sup>53</sup> Cal. Pub. Rec. Code § 3237 (2020).



#### 18.1.8.5 Idle Well Plans

Commenter (0941-350 Silicon Valley) recommends that permit applications for a new well require submission of an Idle Wells Plan, in addition to a Gas Capture Plan. The Idle Wells Plan would include a schedule for plugging and capping all the applicant's older idle wells, defined as those idle for 8 years or more, in the state. This Plan would also include purchase of a bond sufficient to cover the cost of plugging and capping new wells. If its current bonds are insufficient to cover the cost of plugging and sealing its existing wells then if legally possible, the commenter suggests that the dollar amount of those bonds should also be increased. The commenter recommends that in cases where the applicant fails to follow the agreed upon schedule for capping its old/idle wells, the company be required to reduce production at the new well site.

Commenter (1267-CA AG *et al.*) recommends that EPA place limits on the number of idle wells that an individual owner can hold, since a high percentage of idle wells may indicate an increased vulnerability of the operator becoming insolvent and leaving orphan wells. Further, the new source performance standards and emission guidelines should require prompt reporting of any transfer of well ownership.

#### 18.1.8.6 Well Closure Plans

Comment: Several commenters (0844-EDF *et al.*, 1267-CA AG *et al.*, 1282-Earthworks) requested that EPA require the submission of a well closure plan.

Commenter (1267-CA AG *et al.*) recommends that well operators are required to submit a well closure plan describing when and how the well will be closed and demonstrating their financial capacity to comply with the rules until it is closed. This demonstration should include financial assurance to provide money for plugging and restoration if the operator defaults. Allowable financial assurance instruments could include cash deposits, certificates of deposit, irrevocable letters of credit, and surety or performance bonds.

Commenter (1282-Earthworks) recommends that EPA require companies to submit a comprehensive well closure plan in order to properly cap wells at their end of life.

Commenter (0844-EDF *et al.*) recommends that EPA take steps to prevent wells from being improperly abandoned and orphaned by requiring operators to develop and comply with closure plans. The commenter also suggests that EPA require operators to submit plans detailing how they will comply with various standards, like the requirement to submit a fugitive monitoring plan. The commenter adds that EPA should use this approach when dealing with end-of-life wells by requiring operators of well site affected facilities to submit closure plans, detailing how the site will be monitored or plugged, and if the latter, identifying the financing that will be used for plugging, along with other relevant information.<sup>54</sup> When the operator chooses to close a well,

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<sup>54</sup> Section 114, 42 U.S.C. § 7414, gives EPA broad information gathering authority that EPA could use to gain information on operator's financial health. EPA could use that information to identify wells at high risk of abandonment and take proactive steps to prevent those wells from becoming orphaned or transferred. EPA could also provide states with this information, which states could use to inform existing efforts to prevent orphan wells.

thereby removing it from affected facility status, it would be required to follow the steps in the plan. Failure to do so would cause the well site to remain an affected facility, and the operator would have to continue complying with fugitive monitoring and other applicable standards or face noncompliance penalties.

Alternatively, the commenter (0844-EDF *et al.*) suggests that EPA could create a separate abandoned well affected facility definition, for which the standard would be monitoring until proper closure. This would have the same effect as an approach that would allow owners and operators a choice between regular monitoring and well closure with proper plugging. Similar to the “closed landfill subcategory,” EPA could require operators to submit closure plans and require regular monitoring for leaks until the closure plan is completed. The commenter suggests that this option may be more difficult to administer, however, because it would require EPA to define abandoned well affected facilities.

#### 18.1.8.7 Emissions Guidelines Considerations

Commenter (1267-CA AG *et al.*) recommends that EPA address how states evaluate requests by owners/operators of idled and unplugged wells for variances from leak detection and repair requirements based on remaining useful life. EPA could explain, for example, that in reviewing whether a state plan is satisfactory, the agency will take into account whether any variances for these types of wells are conditioned on an enforceable shut down based on the source’s projected remaining useful life.

Commenter (0844-EDF *et al.*) states that, under section 111(d) of the CAA, EPA must allow states when applying a standard of performance to an existing source to consider the remaining useful life (RUL) of the source and other factors.<sup>55</sup> EPA has authority to define how states may consider remaining useful life and may also limit what other factors states consider.<sup>56</sup> The commenter asserts that EPA must require a source that is granted a compliance variance on RUL grounds to commit to a federally enforceable shut-down at the end of its useful life, and must specify the conditions of closure. Any variance justified by a short RUL necessarily entails a certain closure date, and EPA must not allow sources that are permitted to forgo required applicable to all other sources on RUL grounds to continue operating beyond that date.

Further, the commenter (0844-EDF *et al.*) adds that, under section 111(d) of the CAA, EPA can also specify and limit the “other factors” states are allowed to consider when applying a standard of performance to an existing source.<sup>57</sup> The commenter suggests, for example, EPA might require states to consider the financial stability of the operator and specify that EPA would not approve any variance for sources owned by operators with poor finances unless they provide financial assurances to EPA or the relevant state agency. The commenter notes that this could even be done on an operator-wide rather than source-by-source basis. Colorado is updating its financial assurance regulations and may consider the percentage of an operator’s portfolio that is

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<sup>55</sup> 42 U.S.C. § 7411(d)(1).

<sup>56</sup> See *id.*

<sup>57</sup> *Id.*

active versus inactive as a proxy for financial stability.<sup>58</sup> The commenter suggests EPA could do something similar, for example, by requiring a financial demonstration as a condition of approving a variance, or simply not approving a variance for sources owned by an operator with a high percentage of inactive or risky wells.

### ***18.1.9 Identifying and Prioritizing of Abandoned Wells for Monitoring and Closure***

Commenter (0753-IGSD/CHRE) encourages EPA to explore methods for prioritizing, inventorying, and plugging existing abandoned wells based on: the magnitude of emissions; harms to public health, the environment, and the climate; and proximity to environmental justice communities. The commenter states that research demonstrates that a small number of high-emitting wells are responsible for a disproportionate share of methane emissions from abandoned wells.<sup>59</sup> Prioritizing these super-emitters, along with any lower-emitting wells near environmental justice communities first, will best address the climate and justice consequences of unplugged wells.

The commenter (0753-IGSD/CHRE) explains that such a hierarchy would be similar to the prioritization regime in the REGROW Act that Congress enacted as part of the Infrastructure and Investment Act<sup>60</sup> and existing state-level prioritization regimes.<sup>61</sup> The commenter states that

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<sup>58</sup> See Colorado Oil and Gas Conservation Commission, Draft Financial Assurance Rules (Dec. 7, 2021), <https://cogcc.state.co.us/documents/sb19181/Rulemaking/Financial%20Assurance/COGCC%20Draft%20Financial%20Assurance%20Rules%2012-7-21%20-%20Redline%20against%2010-8-21%20Draft.pdf>; Mark Jaffe, Colorado doesn't want to foot the bill for abandoned oil and gas wells. Here's how it will avoid picking up the tab., Colorado Sun (June 17, 2021), <https://coloradosun.com/2021/06/17/colorado-orphan-oil-well-bonding-cogcc/>.

<sup>59</sup> Williams J.P., Regehr A., & Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, ENVIRON.SCI. & TECH. 55:563–570, 569 (“Only 10 high-emitting wells with over 100 g/h have been measured to date, yet they contribute roughly 65% of cumulative emissions (i.e., superemitters) from all studies. Although mitigating a small number of sites can reduce a large percentage of methane emissions, it also means that AOG wells with methane flow rates much higher than those measured to date may exist. Gathering new measurements from regions without prior data may greatly enhance the representativeness of emission factors, help characterize and identify the highest emitters that heavily influence emission factors, and provide information on how these emissions are distributed regionally and across well classifications.”).

<sup>60</sup> 42 U.S.C. §15907(b); Infrastructure Investment and Jobs Act, H.R. 3684, 117th Cong. §40601(b) (2021) (“(ii) ranking those orphaned wells for priority in plugging, remediation, and reclamation, based on-- “(I) public health and safety; “(II) potential environmental harm; and “(III) other subsurface impacts or land use priorities;”)

<sup>61</sup> Rotblat, C. (2017) Caring for the Orphans: Approaches for Mitigating Fugitive Methane Emissions from Orphaned Oil and Gas Wells, ENVIRON. L. REP. NEWS & ANALYSIS 47:10529–10541, 10535 (“States use these funds to maintain prioritized lists of orphaned wells and, as funding permits, to plug the highest priority wells. In 2008, the Interstate Oil and Gas Compact Commission (IOGCC) 97 developed a suggested prioritization schedule for plugging orphaned wells involving 10 factors related to the hazards posed by each well to health, safety, and the environment. However, states still maintain slightly different prioritization systems. For instance, in Texas, prioritization is based on ‘well completion,’ ‘wellbore conditions,’ ‘well locations with respect to sensitive areas,’ and ‘unique environmental, safety or economic concern.’<sup>99</sup> In Kansas, prioritization is based on the risk posed by the well to surface water, groundwater, and public safety. 100 And in Pennsylvania, prioritization is based on ‘whether the well is on public or private land; its distance from public or private water supplies, accessible areas or buildings; its distance from streams, bodies of water, or wetlands; and whether or not it is in a special protection watershed.’ 101 The volume of methane gas leaking from an orphaned well is often taken into account as a public safety factor, due to the risk of ignition or explosion, 102 but the climate change impacts of methane leaks do not appear to be part of any published prioritization system. As a result, even wells leaking significant amounts of methane may remain unplugged for extended periods if they are not located near a water source or occupied buildings. 103”).

EPA should ensure that when addressing abandoned and unplugged wells, methane emissions and climate damage are specifically considered, as well as environmental justice concerns. The commenter states that many existing hierarchies do not reach these critical issues.

Comment: Commenter (0844-EDF *et al.*) recommends that EPA work with states to identify wells at high risk of abandonment and to develop solutions.

Commenter (0753-IGSD/CHRE) encourages EPA to establish a program for identifying undocumented abandoned wells and monitoring emissions at abandoned wells. The existence of known super-emitters (as well as the likelihood that more super-emitters are identified through increased leak detection and repair (LDAR) actions) underscores the importance of monitoring to stop large leaks of methane and other pollutants.<sup>62</sup> Experts emphasize the need to enhance monitoring of abandoned wells (including once plugged) and to document wells not currently identified by states.<sup>63</sup>

Commenter (0598-Countrymark Energy Resources, LLC (CER)) recommends that each state be required to complete an assessment of the abandoned wells and plug the wells that are known to be leaking. The commenter states that this is not an area that EPA should be investing significant resources. High risk, high emission wells should be prioritized through the plugging program to eliminate the emissions source. Monitoring the remaining abandoned wells that may release small volumes of methane and VOCs will add costs for each state. This additional cost will disproportionately impact small businesses through increased fees by the agency responsible for monitoring the wells. Larger companies are better able to absorb the increase in fees to pay for the monitoring, whereas the increases are much more meaningful to the way that small entities

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<sup>62</sup> Williams J.P., Regehr A., & Kang M. (2021) Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, ENVIRON.SCI. & TECH. 55:563–570, 569 (“Only 10 high-emitting wells with over 100 g/h have been measured to date, yet they contribute roughly 65% of cumulative emissions (i.e., super-emitters) from all studies. Although mitigating a small number of sites can reduce a large percentage of methane emissions, it also means that AOG wells with methane flow rates much higher than those measured to date may exist. Gathering new measurements from regions without prior data may greatly enhance the representativeness of emission factors, help characterize and identify the highest emitters that heavily influence emission factors, and provide information on how these emissions are distributed regionally and across well classifications.”).

<sup>63</sup> E.g. Kang M., et al. (2021) Orphaned oil and gas well stimulus—Maximizing economic and environmental benefits, ELEMENTA 9:1–13, 8 (“Here, we outline six policy recommendations for monitoring and managing abandoned oil and gas wells including orphaned wells: 1. Monitor representative populations of plugged and unplugged abandoned wells across multiple basins to understand the ability of plugging to address the full suite and interdependency of environmental risks (Table 1). Ongoing analysis of monitoring results and well attributes are needed to identify representative populations of wells. Moreover, it is important to perform pre- and post-plugging monitoring and understand short-term variations (i.e., daily and seasonal). 2. Study the long-term—decadal to century-scale—impacts of abandoned wells. Such studies should include monitoring at the same wells over decades. 3. Monitor and manage abandoned wells regionally to account for inter-wellbore communication and complex subsurface leakage pathways. The region to investigate will depend on the geology, hydrogeology, and the history of oil and gas and other subsurface activities. Additional research involving field and modeling work is needed to develop a framework for selecting these regions. 4. Find and document wells that are not in current databases so that they can be addressed through plugging and site restoration in a systematic manner. 5. Develop national and international standards for documenting historical and modern wells to improve the long-term maintenance and usability of databases. 6. Train workers on well plugging, site restoration, environmental monitoring, and other jobs that will remain available during and after the transition to clean energy.”).

conduct business. The commenter notes the recently passed infrastructure bill has included funds to plug abandoned wells across the United States.

#### ***18.1.10 Consideration of State/Other Federal Requirements***

Commenters (0391-KBIC, 0781-NTAA, 0605-Muscogee (Creek) Nation, 0833-Ute EPD) are aware of information that the Western Regional Air Partnership has developed that may support EPA's regulation of these activities.<sup>64</sup>

Commenters (0391-KBIC, 0605-Muscogee (Creek) Nation, 0833-Ute EPD) note that they are also aware of the activities in states such as Pennsylvania and Ohio to identify and address abandoned and orphaned wells.<sup>65,66</sup>

Commenter (0803-Ohio Oil and Gas Association (OOGA)) asserts that EPA's regulation of abandoned wells in Ohio is unnecessary. In the November 2021 Proposal, the commenter notes that EPA requests comments to inform its potential development of NSPS and EG for emissions from abandoned wells. The commenter adds that EPA notes that it broadly defines "abandoned wells" as "oil and natural gas wells that have been taken out of production, which may include [wells that are] . . . idle, inactive, dormant, or shut-in, but not plugged. The Ohio Department of Natural Resources, Division of Oil and Gas (ODNR) is the agency vested with statutory authority to regulate all aspects of the permitting, location, and spacing of oil and gas wells and production operations, including, specifically, the plugging and abandonment of wells in Ohio. According to the commenter, EPA developing regulations to address emissions from abandoned wells is unnecessary and may potentially conflict with existing state regulations in Ohio.

Commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) notes that EPA identified a potential strategy to imply practices and procedures to ensure proper well closure that may conflict with existing state regulation. The commenter states that a federal air quality regulation addressing well closures would require significant interagency coordination beyond current levels. The commenter provides details on the West Virginia abandoned wells program, and states that lack of funding is problematic, not lack of regulation. The commenter adds that the Office of Oil and Gas (OOG) is the agency vested with the authority to regulate well closures in West Virginia. An OOG legislative rule establishes abandoned well requirements that include financial responsibility and a priority system for plugging abandoned wells. West Virginia estimates there are 15,000 documented abandoned wells, including 6,300 orphaned or unbonded wells in the state with a projected average cost of \$100,000 to plug each well. The commenter reports that the state began

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<sup>64</sup> Oil & Gas Work Group, Western Regional Air Partnership, <https://www.wrapair2.org/OGWG.aspx>.

<sup>65</sup> Rewriting Pennsylvania's Legacy Plugging & Plugging Support Contractor Survey, Penn. Dept. of Env'tl. Prot. (July 2021),

<https://www.dep.pa.gov/Business/Energy/OilandGasPrograms/OilandGasMgmt/LegacyWells/Pages/default.aspx>.

<sup>66</sup> Kathiann M. Kowalski, Thousands of Abandoned Ohio Oil and Gas Wells May be Hidden. Drones Could Help Find Them, Energy News Network (May 10, 2021), <https://energynews.us/2021/05/10/thousands-of-abandoned-ohio-oil-and-gas-wells-may-be-hidden-drones-could-help-discover-them/>.

permitting wells in 1929, and it is unknown how many undocumented wells existed prior to 1929.

Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) suggests that any proposal to include abandoned and unplugged wells as additional sources for regulation under the CAA would be premature, considering all the ongoing work at the state level and the provisions for additional state plugging and abandoned well research and development expected pursuant to the Infrastructure Investment and Jobs Act of 2021.

Commenters (0810-Petroleum Alliance-OK, 0814-Independent Petroleum Association of America (IPAA) *et al.*) believe that EPA should defer to states to address future orphaned wells. If EPA proposes requirements, the commenters state that EPA needs to provide detailed rationale for its authority. The commenter states that in order to prevent wells from becoming orphaned in the future is complicated. States recognize this issue and are reviewing their programs, statutes, and rules to determine the best course of action to prevent the occurrence of these types of wells. States, like Oklahoma, according to the commenter, are in the best position to address future orphaned wells.

Commenter (0814-IPAA *et al.*) notes that a major issue not addressed in the November 2021 Proposal is various specific agreements, memorandums of understanding and plugging consent orders. The commenter suggests that for EPA come in run roughshod over these existing arrangements would represent a step backwards. The detailed rationale for its authority to regulate the “emission sources” should include why the states should not have primacy in addressing the issue. The commenter believes that EPA lacks authority regulate well bonding.

Commenter (0814-IPAA *et al.*) notes that EPA broadly characterizes abandoned wells as oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells such as idle, inactive, dormant, shut-in, and orphaned wells. These wells, except for orphaned wells, typically have a responsible owner/operator but are not producing for a specific reason *e.g.*, product pricing, held by other production in the unit, or waiting on some specific activity like a workover. On the other hand, an orphaned well is a well where there is no responsible owner/operator *e.g.*, the owner/operator has gone bankrupt. The commenter recommends that EPA not broadly characterize these wells collectively as they are very different and the existing state programs are addressing this problem with much appreciated federal assistance. The commenter suggests that for EPA to attempt a federal overlay of the state programs would represent a step backwards.

Commenter (0744-New York State Department of Environmental Conservation (NYSDEC)) requests that EPA investigate the feasibility and practicality of federal regulation of abandoned wells in close coordination with New York and other oil and gas producing states as there are substantial differences among states with respect to the construction of oil and gas wells, the surrounding geology and the states’ regulatory programs. The commenter notes that EPA lumps idle and orphaned wells into the abandoned category, but states like New York have limited ability to regulate orphaned wells, compounded by a lack of access to these wells on private property. The commenter supports EPA's interest in reducing the numbers of future orphaned

wells by working with active operators now, however EPA should consider whether any requirements to retrofit wells to abate GHG emissions may lead to an increase in orphaned wells in New York. The commenter further supports well plugging and shut in requirements to prevent methane emissions and recommends that well conditions are carefully considered in any future requirements as well construction and conditions differ among states. The commenter states that sealing a well off from the atmosphere has the potential to impact the aquifer due to over-pressuring of the well bore. The commenter recommends that EPA reach out to oil and gas producing states to examine the different requirements and data collection activities currently in place. For example, New York requires operators to request shut-in status for wells that are not producing for one year. In addition, the commenter inspects wells prior to approving shut-in status. The commenter has provided information on New York's idle well program and provided orphaned and idle well counts to IOGCC previously and recommends this organization as a good source of statistics and information on the different programs in IOGCC's member states.

Commenter (0957-WYCLG) states that EPA must avoid adopting any duplicative regulations for the proposed NSPS that it may develop for abandoned and unplugged wells. The commenter suggests that one strategy EPA is considering for supplemental rulemaking is adopting practices and procedures to ensure proper well closure to help reduce emissions from abandoned wells. This would include the requirement to submit a closure plan describing when and how the well will be closed and demonstrating the financial capabilities of an operator to comply with closure requirements. However, the commenter notes that most of the oil and natural gas producing states require the plugging of non-producing wells and subsequent restoration of the well site.

Commenter (0808-API) believes that issues related to well closure are more appropriately addressed by the states and BLM. The commenter recommends that EPA consider all available information before developing policy. The commenter notes that substantial progress on – and additional information concerning - idle/orphaned well clean up may be expected based on recent federal funding. Passed as part of the Infrastructure and Investment Jobs Act of 2021, the REGROW Act provides funding to invest in the environment, and a skilled workforce. This includes \$4.275 billion for orphaned well clean up on states and private lands, \$400 million for orphaned well cleanup on public and tribal lands, and \$32 million for related research, development, and implementation.<sup>67</sup> Any applications from states for these grant funds can help provide more concrete numbers. Additionally, any of these funds that are distributed as grants to state agencies may contain additional environmental and reporting obligations, which, when viewed in the proper context, may lend additional light to this issue. The commenter states that these recent developments further minimize the need or justification for EPA to expand its regulatory efforts on this topic to encompass orphan wells.

The commenter (0808-API) notes that further granularity on idle/orphaned wells was provided in December 2021, when IOGCC released an update of its 2019 report on idle and orphaned wells to include 2019 – 2020 data. Because IOGCC's work is based on over 30 years of review, the commenter recommends that EPA consider this information carefully before determining a course of action.

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<sup>67</sup> REGROW Act Infrastructure and Investment Jobs Act of 2021, H.R. 3684, 117th Congress (2021).

The commenter (0808-API) instructs that IOGCC is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. As an organization, IOGCC is committed to continuing to support the states and provinces in their efforts to continually improve their idle and orphan well programs and to providing a forum for information-sharing of effective tools and strategies. IOGCC has also been included in the (DOI) Memorandum of Understanding (MOU)<sup>68</sup> for the recently enacted grant program referenced above.

Across decades of studying idle and orphaned wells, the commenter (0808-API) reports that IOGCC has published reports on the issue in 1992, 1996, 2000, 2008, and 2019.<sup>69</sup> A new report covering data from 2019 and 2020 was published in December 2021.<sup>70</sup> As these reports show, IOGCC has been following this issue for 30 years. The commenter encourages EPA and other agencies interested in regulations on this topic to review the report in detail.

The commenter (0808-API) provides that the 2021 IOGCC report features survey responses from 32 IOGCC member and associate member states and five Canadian providences. It includes data from 2018 – 2020 and concerns the number of both idle and orphan wells, well plugging and site restoration costs, and remediation strategies (including regulatory tools and funding sources used to ensure idle wells are properly maintained). The commenter notes that oversight for idle, orphan, and historical undocumented orphan wells is state-specific according to local regulatory programs, most of which include requirements for wells to remain idle and established prioritization systems for known orphaned wells. Additionally, the commenter reports that most states already have funding mechanisms for plugging orphan wells, which are supported by industry taxes and fees. To avoid duplication or unintended consequences, the commenter recommends that EPA carefully examine these diverse programs and funding mechanisms prior to any additional regulatory work.

As an example of continuous improvement within the applicable states, the commenter (0808-API) reports that over half of the states and provinces participating in the IOGCC survey reported improvements in their idle and orphan well programs between the IOGCC reports in 2008 and 2021. In 2019, IOGCC noted that these included “process improvements in communication, collaboration, contracting, third-party plugging, compliance assurance, data systems, and bonding; implementation of program efficiencies; increases in staffing and funding; and application of Geographic Information System (GIS) and drone technologies. Through the decades, the states and provinces have made considerable progress in plugging orphan wells and reducing the likelihood of additional wells becoming orphaned. They have also continued to evaluate and adjust their financial assurance requirements and their plugging funds to ensure there will be funds available for well plugging and site restoration.”<sup>71</sup>

The commenter (0808-API) asserts that the 2021 IOGCC report expanded its description of regulatory strategies used by the various states which include, “requirements, such as periodic mechanical integrity testing, that must be met for wells to remain idle beyond a specified time.

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<sup>68</sup> Orphan Well MOU (doi.gov).

<sup>69</sup> IOGCC, Idle and Orphan Oil and Gas Wells, (2019).

<sup>70</sup> IOGCC Idle and Orphan Oil and Gas Wells, (2021).

<sup>71</sup> IOGCC (2019) at 21.



These requirements may be set by statute, rule, or written approval. Most states and provinces also require financial assurance to provide money for plugging and restoration if the operator defaults. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. The types accepted and amounts required vary considerably among the states and provinces. The participating states all provide for single-well and blanket coverage, and the participating provinces provide for either single-well or blanket coverage, or both. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well or case-by-case evaluations. To supplement the funds provided through financial assurance instruments, most states and provinces have established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry. Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using GIS and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration.”<sup>72</sup>

The commenter (0808-API) adds that the activities on federal lands are regulated both by BLM regulations and by the state in which the operations are located. On federal lands, however, existing federal regulations obligate companies to bear the full costs of plugging and abandoning well sites.<sup>73</sup> In fact, companies cannot be released from liability until BLM determines they have properly done so. The April 2019 GAO report identified 296 orphaned wells which is a very small and manageable percentage of the 96,199 onshore federal wells.<sup>74</sup>

Beyond state and federal requirements, the commenter (0808-API) notes that the oil and gas industry has developed relevant standards and practices which apply on both state and federal lands. These are relevant throughout a well’s lifecycle; covering the safe conduct of drilling operations, standards for equipment and materials used during drilling and completion, and practices for well plugging and abandonment. In 2021, API’s Recommended Practice (RP63),<sup>5</sup>-Wellbore Plugging and Abandonment provided specific guidance for the design, placement and verification of cement plugs used in wells that will be temporarily or permanently closed.<sup>75</sup> The standard also provides guidance for well remediation and verification of annular barriers, reinforcing groundwater protection and emissions retention. RP 65-3 joins several established API standards already in use for decades, including but not limited to API 51R, Environmental

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<sup>72</sup> IOGCC (2021) at 3.

<sup>73</sup> Ref federal regs See *e.g.*, Bureau of Land Management, Onshore Order No. 253 Fed. Reg. 223 (1988), available at [https://www.blm.gov/sites/blm.gov/files/energy\\_onshoreorder2.pdf](https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder2.pdf), and other onshore orders available at <https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/onshore-orders>.

<sup>74</sup> Government Accountability Office, Report 19-615 Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Repair Wells (2019) p. 14, citing Footnote 30 explaining that anecdotally BLM also indicated some of these 296 wells may no longer be orphaned.

<sup>75</sup> API RP-63 American Petroleum Institute, Recommended Practice 65-3, Wellbore Plugging and Abandonment (2021).

Protection for Onshore Oil and Gas Production Operations and Leases and API 65-2, Isolating Potential Flow Zones During Well Construction. These are instructive templates for better understanding how industry practices work effectively across varying state and federal regulations.

Commenter (0831-AXPC) notes that the November 2021 Proposal suggests that EPA is considering requirements for operators to have to submit plans for plug and abandonment along with associated financial assurance for decommissioning obligations. The commenter believes issues related to well closure are more appropriately addressed by the states and federal land management agencies like the BLM. State oil and gas agencies and federal land management agencies (*i.e.*, BLM) have the authority to regulate the management and decommissioning of oil and gas wells. Operators are already subject to regulatory requirements for posting financial assurances to cover decommissioning costs and clean up, submittal of plans and technical procedures for temporarily abandoning or permanently decommissioning a well. In addition to this potential for creating redundant regulations, EPA has no authority under the CAA to impose such a financial assurance requirement.

The commenter (0831-AXPC) asserts that it is also important to note that state oil and gas regulators and other parts of the U.S. government are already considering and addressing the issues that EPA has raised related to the proper management of idle well inventories, providing for proper well abandonment, as well as addressing the existing inventory of orphan wells. For example, IOGCC is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. IOGCC has been studying this issue for 30 years and supporting states and provinces in their efforts to continually improve their idle and orphan well programs and sharing effective tools and strategies. As recent as December 2021,<sup>76</sup> IOGCC issued an updated report entitled “Idle and Orphan Oil And Gas Wells: State and Provincial Regulatory Strategies 2021.” In this report, IOGCC found that less than 6 percent of all drilled and not plugged (includes all operational wells) are considered orphaned by the states. Of these orphaned wells, the operator is known for 78 percent of the wells. Estimates for the number of undocumented wells, legacy wells typically drilled prior to the establishment of regulatory programs, are much higher. However, the commenter asserts that the existence of these undocumented wells should not be conflated with the modern definition of orphan wells, which are managed through various techniques such as bonding and state/operator funded orphan well plugging programs. IOGCC’s work and recent report should be relied upon for establishing consistent terminology, improving counts and estimations, and reviewed carefully before considering additional regulations.

### ***18.1.11 Regulatory Funding***

Commenter (0734-ATS) commends the Biden Administration for allocating \$4.7 billion in their infrastructure legislation to plug existing abandoned wells and mines.

Commenters (0808-API, 0810-Petroleum Alliance-OK, 0814-IPAA *et al.*) note that President Biden signed into law the infrastructure bill that includes over \$4 billion in funding to restore and plug orphaned wells on federal, state, private and tribal lands (aka REGROW Act of 2021). In

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<sup>76</sup> [https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc\\_idle\\_and\\_orphan\\_wells\\_2021\\_final\\_web.pdf](https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf).

December 2021, the Department of Interior released guidance on state applications for grants under the program. Since then, the commenters provide that many states, including Oklahoma, have applied for this funding, and are aggressively prioritizing and addressing the plugging of orphaned wells. The commenters add that IOGCC has been working with states and provinces to evaluate their idle- and orphan-well programs and identify useful regulatory tools and strategies to address this issue. In addition, in Oklahoma, the industry voluntarily takes responsibility for orphaned well sites and has invested over \$132 million to clean up over 18,000 orphaned wells sites.

Commenters (1270-LWVUS) state that plugging abandoned wells must be a top priority to help protect us from extreme global warming, but questions who will pay. In cases where the ownership of abandoned wells can be traced to companies still in business, the owners can be asked to provide funding, but there may be no legal route for extracting money from an unwilling owner. The commenter note that states were supposed to secure sufficient funding through bonding to pay for necessary decommissioning activities, including plugging. In general, the commenters report that they did not require anywhere near sufficient funds from owners to complete the work, and most will be unable to pay for it from state budgets.

Commenter (1270-LWVUS) notes that The Bipartisan Infrastructure Investment and Jobs Act, a Part of the “Build Back Better Plan” as envisioned in March, 2021, promised “. . . an immediate up-front investment of \$16 billion that will put hundreds of thousands to work in union jobs plugging oil and gas wells and restoring and reclaiming abandoned coal, hardrock, and uranium mines.”<sup>77</sup> The commenter states that this funding might have provided a start on plugging wells, but it isn’t clear that any such language will be included in whatever legislation is finally passed. The commenter notes that, if passed, the commenter believes that the Build Back Better legislation is likely to provide only a tiny portion of the funding that will eventually be required.

According to a 2020 analysis, commenter (1270-LWVUS) reports that an estimated \$280 billion in funding would be required to clean up the 2.6 million unplugged onshore mines that have been documented to date.<sup>78</sup> The commenter adds that an unknown sum will be required to plug an estimated 1.2 million onshore wells that are believed to be unplugged but are not yet documented. An estimated 1.7 million gas and oil wells are currently active.<sup>79</sup> The commenter states that many are likely to be closed down in the next decade. The commenter believes that the total cost of plugging all these wells will almost certainly exceed \$500 billion.

The commenter (1270-LWVUS) recommends that EPA plan for extensive and long-term work to identify and plug abandoned and orphaned wells. The commenter states that EPA will need to investigate a variety of possible funding sources to secure funding to carry out the vital campaign to plug abandoned wells.

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<sup>77</sup> <https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/31/fact-sheet-the-american-jobs-plan/>.

<sup>78</sup> <https://carbontracker.org/reports/billion-dollar-orphans>.

<sup>79</sup> Oil & Gas Activity in the U.S. (fractracker.org)

There are ~1.7 million active oil and gas wells in the U.S. This map includes both conventional and unconventional (e.g., fracking) wells.

Commenter (0573-KDHE) recommends that EPA or other federal agencies provide states with significant additional funding to address shortfall in plugging abandoned wells. In its 2021 annual report on abandoned oil and gas wells<sup>80</sup> the Kansas Corporation Commission provides estimates of the number of abandoned wells requiring action (5,632 currently), as well as the average cost of plugging by state district. These costs range from approximately \$4,000 per well in southeast Kansas, where shallow coalbed methane (CBM) wells predominate, to \$15,000 in the Hays District, where oil wells predominate. The current program had funds to plug only 159 wells in FY 2020.

Commenter (0598-CER) expresses concern that EPA's additional regulations will add costs to wells that are marginally profitable that could lead operators to decide to terminate their business. While operators are required to maintain bonding for each operator, in the event that this occurs, the commenter has witnessed that the funds from the surrendered bonds are not utilized to plug the operators remaining wells. As a result, the commenter suggests that taxpayers will ultimately pay to plug the wells. The commenter is concerned that the additional regulations will result in many more wells being surrendered to state agencies. Historically, the commenter has seen operators surrender their wells to state agencies to complete remediation of the unplugged wells at the time that the operator ceases to do business.

Commenter (0558-Center for Climate and Energy Solutions (C2ES)) recommends that EPA establish strict criteria that states must demonstrate to be granted funding, including proximity of abandoned wells to frontline communities and ensuring that funding is provided to orphan wells (*i.e.*, no known operator or owner). In 2019, EPA estimated that methane emissions from abandoned oil and gas wells are 6.6 MMT carbon dioxide equivalent (CO<sub>2e</sub>).<sup>81</sup> Fifty-nine percent of these abandoned oil and gas wells are unplugged (almost 2 million wells) which makes them more likely to pose greater health and environmental risks. While different states allocate funds dedicated to plugging abandoned wells and restoring well sites, the scale of the challenge is beyond their capabilities.<sup>82</sup> The commenter notes that the funding for legacy pollution clean-up included in the recently enacted Infrastructure Investment and Jobs Act, which includes establishing new state programs for orphaned wells plugging and remediation, should give EPA an opportunity to help states address methane emissions from abandoned wells.<sup>83</sup>

#### ***18.1.12 Opposition to Regulation of Emissions from Abandoned Wells Without Further Consideration***

Commenter (0792-Interstate Oil and Gas Compact Commission (IOGCC)) is concerned with EPA's solicitation of comments and information on "abandoned and unplugged wells." The commenter notes that the November 2021 Proposal includes a brainstorm of ideas on potential regulations for "abandoned, idled, and non-producing wells" without clearly defining the terms used, without understanding how various elements of a state regulatory program operate as a

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<sup>80</sup> [https://kcc.ks.gov/images/PDFs/legislativeeports/2021\\_Abandoned\\_Oil\\_and\\_Gas\\_Well\\_Status\\_Report.pdf](https://kcc.ks.gov/images/PDFs/legislativeeports/2021_Abandoned_Oil_and_Gas_Well_Status_Report.pdf).

<sup>81</sup> U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2019.

<sup>82</sup> IOGCC, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies (Oklahoma City, OK: IOGCC, 2019).

<sup>83</sup> Infrastructure Investment and Jobs Act, H.R. 3684, 117th Congress, (2021), <https://www.congress.gov/bill/117thcongress/house-bill/3684>.

system, and without considering the potential adverse impact of EPA's ideas on the state regulatory programs and the inventories of idle and orphan wells.

The commenter (0792-IOGCC) adds that the discussion of “abandoned wells” in the November 2021 Proposal highlights the imperative of immediate action to convene the IOGCC and EPA’s Memorandum of Understanding Task Force. The commenter suggests that, among the items the Task Force should discuss is IOGCC’s latest report, *Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021*, which was released in December 2021. This report outlines the regulatory tools and funding sources used to ensure that responsible operators properly maintain and timely plug idle wells and that states have funds to plug orphan wells. The commenter adds that the Task Force should also review the work underway in the states to accelerate the plugging of orphan wells with funding to be provided through the Infrastructure Investment and Jobs Act of 2021.

Commenter (0742-Alaska Department of Environmental Conservation (ADEC)) recommends that EPA exclude abandoned and unplugged wells from this proposal because these are best suited to be addressed by resource agencies devoted specifically to this issue as many states already have in place. Abandoned and unplugged wells are a separate issue in Alaska, where the majority of unplugged and abandoned wells are on federal lands.<sup>84</sup> As Alaska does not accept delegation of individual subparts at what would truly be minor or area sources, the requirement to deal with abandoned and unplugged wells in Alaska already primarily falls upon the federal government, not the state. In 1982, BLM inherited the responsibility to assess, plug, and clean up the wells that the U.S. Navy and United States Geological Survey (USGS) left behind.<sup>85</sup>

Commenter (0756-Baker Hughes) does not support expanding the proposed NSPS and EG to abandoned or non-producing wells because there is no clear authority under the CAA and the management of operating wells are regulated by the states under long-established programs for drilling, operations, well plugging, and site reclamation. To avoid duplication or unintended consequences, the commenter recommends that EPA carefully examine the authority under the CAA, the ability to regulate an asset that has no owner or operator, and existing state regulatory programs prior to any expanding the regulatory scope of the proposed NSPS and EG.

Commenter (0599-MSA) notes that existing wells will vary in construction and methods for appropriate mitigation and believes this is an issue best addressed at a state level.

Commenter (0585-Kentucky Oil and Gas Association (KOGA)) notes that the Kentucky Energy and Environment Division of Oil and Gas has had an active cataloging and plugging program for abandoned and orphan wells for decades. The Cabinet reports and estimated 14,000 orphaned and abandoned wells across the state. These wells were primarily abandoned before the Kentucky’s Oil and Gas Conservation Act of 1960 when permitting newly drilled wells began. Cataloging of these wells has included field inspections and prioritizing wells for plugging that pose the greatest environmental impacts. In 2020, the State of Kentucky plugged 299 wells and

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<sup>84</sup> “legacy wells” that the federal government drilled between 1944 and 1981), Alaska Legacy Wells | Bureau of Land Management (blm.gov).

<sup>85</sup> <https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/alaska-legacy-wells>.

could have plugged more but was limited by funding. The recently passed infrastructure bill has included funding to plug abandoned wells across the United States, and the KECC is already making plans to utilize those funds. The commenter does not foresee the benefit of EPA's potential monitoring requirements for wells that are included in the State of Kentucky's existing plugging program. Requiring Kentucky's Division of Oil and Gas to monitor the remaining abandoned wells, which may or may not release small volumes of methane and VOCs, will only increase operating costs for the division. The commenter states that these additional costs will shift the operating costs to operators through higher fees or citizens through higher taxes.

Commenters (0808-API, 0831-AXPC) state that EPA should exclude requiring a demonstration of financial capacity in the upcoming supplemental proposal because EPA does not have authority under the CAA to impose financial assurance requirements. The commenters note that EPA and states have authority under the CAA to establish "standards of performance" applicable to affected facilities as defined in CAA section 111(a)(1) to mean, in relevant part, "a standard for emissions of air pollutants" – *i.e.*, an emissions limitation or comparable requirement (such as an equipment or work practice standard). This is reinforced by the more broadly applicable CAA section 302(l) definition of "standard of performance," which defines that term to mean "a requirement of continuous emissions reduction." The commenters argue that neither of these definitions can reasonably be construed as authorizing EPA to issue financial assurance requirements for affected facilities. In conjunction with the obligation of EPA and states to issue standards of performance, the CAA section 114(a) provides authority to establish corresponding compliance assurance measures, such as monitoring, recordkeeping, and reporting requirements. However, the commenters explain that a financial assurance requirement is fundamentally different in kind from such measures. Monitoring, recordkeeping, and reporting are designed to provide information necessary to determine applicability and demonstrate compliance with a standard of performance. In contrast, a financial assurance requirement is designed to make sure enough money is available to implement a standard of performance at some point in the future. Notably, in instances where Congress wants EPA to require financial assurance, authorization has been explicit. See, *e.g.*, 42 U.S.C. section 6924(a)(6) (Requiring EPA to establish rules for treatment, storage, and disposal facilities regulated under the Resource Conservation and Recovery Act to ensure "the maintenance of operation of such facilities and requiring such additional qualifications as to ownership, continuity of operation, training for personnel, and financial responsibility (including financial responsibility for corrective action) as may be necessary or desirable."). The commenters assert that the absence of such an express provision in the CAA cannot be construed as a grant of authority.

### ***18.1.13 Continuous Monitoring and Emissions Mitigation (Containment) Technologies***

#### **18.1.13.1 Continuous Monitoring Systems**

Commenter (0933-LongPath Technologies, Inc. (Longpath)) provides details on their inexpensive continuous monitoring systems. The commenter notes that states, the federal government, and tribal nations are facing a challenge in effectively identifying and measuring methane emissions originating from legacy oil and gas wells.

The commenter (0933-Longpath) reports that it creates basin-wide continuous monitoring networks that make it extraordinarily inexpensive to provide either short-term or long-term monitoring of individual sites under the purview of a given node (laser system). Abandoned and orphaned wells share three critical characteristics that make them difficult to prioritize for repair: 1) emission rates are relatively low,<sup>86</sup> 2) emission rates are variable through time,<sup>87</sup> and 3) to cost-effectively prioritize repair, characterizing emissions must be done at a very low cost. The commenter contends that it is uniquely positioned to meet all three needs.

The commenter (0933-Longpath) notes that their system is the only peer-reviewed published continuous monitoring system capable of quantifying emission rates at a small enough rate to provide a match to abandoned wells. The thresholds of detection for aircraft surveys are, by contrast, orders of magnitude too high.

The commenter (0933-Longpath) provides continuous monitoring, which the literature shows is necessary for accurately characterizing abandoned well emissions. According to peer-reviewed studies, “high CH<sub>4</sub> emission events tend to be short-lived, so short-term (< 1 h) sampling is likely to miss them.”<sup>88</sup> Furthermore, continuous monitoring of emissions will be required following their full decommissioning to demonstrate repair effectiveness.

The commenter (0933-Longpath) contends that their unique method of networked area coverage means that marginal and abandoned well sites can be “subscribed” to monitoring coverage for a very low cost. According to the commenter, a very modest capital investment would provide the infrastructure necessary across large areas (e.g., the entirety of the Permian Basin), enabling low-cost continuous monitoring for all operators as well as for marginal and abandoned well sites.

#### 18.1.13.2 Well Closure/Plugging

Commenter (0364-WellHead Emissions Management Systems (WHEMS)) describes Abandoned Oil and Gas Wellheads (AOGW) emissions and a potential cost-effective mitigation solution.

- a. AOGW, by modest accounts, number over 3,000,000 across the United States, and by modest calculations emit over 7,000,000 metric tons of methane emissions per year.
- b. Methane is not the only emission coming from these AOGWs. VOCs and HAP are also freely emitted from the unplugged AOGW.
- c. Smith Analytical has recently used a mobile lab to test AOGWs along with operating wells at the Alabama-Coushatta Tribe of Texas and found benzene, toluene ethylbenzene, and xylene (BTEX) in the leaking effluent. The benzene was measured at rates 3,000 times higher than any refinery fence line program as defined by EPA Method 325A/B. When elevated benzene readings were measured, the toluene, ethylbenzene and xylenes were also elevated (See Table 1 in commenter’s letter).
- d. CH<sub>4</sub> emissions by itself is 90 times more potent than CO<sub>2</sub> which is thought to be the leading cause of climate change.
- e. AOGW, or improperly maintained operating wells, are a significant problem and are

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<sup>86</sup> Kang et al., “Direct Measurements of Methane Emissions from Abandoned Oil and Gas Wells in Pennsylvania.”

<sup>87</sup> Riddick et al., “Variability Observed over Time in Methane Emissions from Abandoned Oil and Gas Wells.”

<sup>88</sup> Id.

acknowledged as such by Republicans, Democrats, as well as various non-profit advocacy organizations such as Greenpeace and Sierra Club.

The commenter (0364-WHEMS) states that the only way to remedy these AOGWs is through the plugging of the well. The commenter notes that this process is expensive, and no state in the U.S. requires that sufficient financial resources be allocated to cover oil and gas drilling, and well head repair costs. One plugging job can range in cost from \$25,000 - \$300,000 and add financial uncertainty for oil and gas companies. The commenter proposes the following Smith Analytical U.S. patented method (U.S. Patent 10,753,204 B2) industry solution to mitigate emissions, that results in over 99 percent elimination of all emissions (CH<sub>4</sub>, VOC, HAP).

1. The Methane/VOC Mitigation System (MVMS) uses a containment system produced of Tedlar® or more commonly steel containment system to encase the leaking AOGW or problematic equipment. Then, by measuring the lower explosive limit (LEL) of the air-hydrocarbon mixture inside the containment vessel, a Programmable Logic Controller (PLC) trips when the internal atmosphere is high enough to safely transfer the emissions to a converter such as the Emission Master, which eliminates the fugitive emissions from the AOGW at a rate of plus 99 percent.
2. The MVMS can also be configured to also scrub the emissions and capture them in a filtration system using 13X Zeolites.
3. Unlike the incredible expense of plugging these AOGWs, the MVMS can be installed and operated for around \$400/mo. (Note the monthly rate varies based on the location, emissions rate and the term of the rental).
4. The MVMS provides a datalink of real-time mitigation, allowing the stakeholder to observe the measurement of emissions in the effluent of the MVMS. The system provides hourly, monthly, and quarterly CH<sub>4</sub>/ VOC emissions reports and provides the Stake Holder with quantifiable information regarding the emissions which have been scrubbed or converted into CO<sub>2</sub>, water vapor and nitrogen (N<sub>2</sub>).
5. For the cost of one AOGW plugging or repair, the stakeholder can use the MVMS system on 5 to 42 AOGWs for a year. This creates an immediate measurable stop-gap solution that is both affordable and effective.

The commenter (0364-WHEMS) notes the following value-added benefits.

1. The Smith Analytical MVMS is a cost-effective application that saves its users millions/year, reduces emissions by nearly 100 percent, and identifies environmental, health, and safety impacts globally.
2. The Smith Analytical MVMS has a proprietary method for quantifying the leak rate of an AOGW using the steel containment system which is installed over the AOGW. As the MVMS is a relatively mobile platform, the stakeholder can have this system installed for a period of ten (10) to thirty (30) days to determine the severity of the leak. As the AOGW inventory is processed, the stakeholder can prioritize the long-term repair of the AOGW or locations that require a long-term MVMS.
3. The MVMS can be remotely monitored via a wireless network to ensure the hardware is performing as designed.



4. The MVMS requires 110VAC to operate or can be fitted with solar and or wind-powered generation hardware to provide the necessary power for the MVMS.

## **18.2 Pigging Operations**

Response I-18-2: In the November 2021 Proposal, EPA solicited comment and data to assist the Agency in evaluating the potential for developing emissions standards for additional emission sources, including pigging operations and related blowdown activities. EPA did not propose emissions standards pigging operations and related blowdown activities in the December 2022 Supplemental Proposal; therefore, this final action does not include emissions standards for these emission sources. We may consider regulation through a future action, including in the next 8-year review of the NSPS. The comment summaries are provided below for reference but substantive responses are not provided because no emissions standards have been proposed for this emissions source.

### ***18.2.1 Regulatory Support***

Commenters (0599-MSD, 0817-GPA Midstream Association (GPA)) state that EPA fails to provide clarity or proposed language on which the commenter can adequately comment. Definitive regulatory text is needed for the commenter to provide truly meaningful comments as to the effects of any proposed regulation. In addition, the commenters note that additional information regarding the feasibility and costs associated with any proposed control technologies are required pursuant to a proposed NSPS.

Commenters (0599-MSD, 0817-GPA) assert that implications of any sort of proposed regulation and/or classification regarding blowdowns cannot be ignored. For example, the commenters state that EPA must consider how such a regulation would impact permitting and how or whether regulated entities would be required to preemptively permit each and every meter station or valve where a blowdown may occur. The commenters contend that the NSPS continuous monitoring requirements would lead to similarly absurd results where blowdown is sporadic, random, and occurring as needed.

Commenter (0957-WYCLG) states that the solicitation of comments on the potential for establishing standards for pipeline pigging and related blowdown activities is not appropriately included within the November 2021 Proposal because it fails to provide an adequate description of the issues involved or terms or substance of a proposed rule. The commenter recommends that this request for additional information on other sources of emissions instead be its own separate rulemaking, starting with an “Advance Notice of Proposed Rulemaking” to obtain the necessary information.

### ***18.2.2 Support for Regulation of Emissions from Pigging Operations/Blowdowns***

Commenter (1414-Sane Energy Project (SEP)) asserts that fugitive methane emissions reportage must include gas emitted into the atmosphere via “blowdowns” (intentional venting) and leakages from compressor stations.

Several commenters (0391-KBIC, 0458-Maryland Department of the Environment (MDE), 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0744-NYSDEC, 0776-Air Pollution Control Division, Colorado Department of Public Health and Environment (CDPHE), 0789-Pennsylvania Department of Environmental Protection (PADEP), 0781-NTAA, 0809-Earthjustice, 0832-New Mexico Environment Department (NMED), 0833-Ute EPD, 0943-Sault EPD, 0844-EDF *et al.*, 0918-COLGC, 1302-WYOC/PRBRC) express support for the regulation of emissions from pigging operations/blowdowns. Examples of some of the specific comments are provided in the following paragraphs.

Commenter (0809-Earthjustice) recommends that EPA not delay its duty to regulate these significant sources of uncontrolled emissions simply because of inadequate data. The commenter suggests that, if a targeted Information Collection Request (ICR) is necessary to supply the agency with data it requires, then the agency should undertake this information gathering without delay and well in advance of its rulemaking deadlines.

The commenter (0809-Earthjustice) notes that the November 2021 Proposal does not include standards, but rather seeks comments. The commenter asserts that pipeline pigging operations have the potential to emit large amounts of VOCs, methane, and HAPs. Emissions from pigging “can exceed fifty (50) tons of VOC per year” in oil operations and “in the range of one (1) to two (2) tons of VOC per year” in natural gas operations, according to comments provided to EPA by the Colorado Department of Health and the Environment.<sup>89</sup> These estimates align with recent permit reviews in Pennsylvania, where EPA has entered a consent decree requiring midstream operators to include emissions from pigging sources and requirements to control those emissions in applications for operating permits.<sup>90</sup>

Commenter (0789-PADEP) suggests that EPA consider regulating natural gas emissions from blowdown activities. The commenter notes that since 2018, Pennsylvania has required pigging operations to employ a variety of best management practices to minimize emissions, in addition to a 95 percent emission reduction requirement for high emitters. Based on the state’s experience, the commenter recommends that EPA define pigging operations as a source category and include appropriate emission limits.

Commenters (0391-KBIC, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-Ute EPD, 0943-Sault EPD) support regulation of emissions from pigging operations and related blowdown activities. The commenters state that they understand that technologies are available, feasible, and cost effective to prevent harmful emissions of methane, VOCs, and HAPs during these operations. The commenters add that they support a combination of the strategies identified as potential control options.

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<sup>89</sup> Reconsideration Petition, *supra*, at 29.

<sup>90</sup> See Memo from Bradley Spayd, Pa. Dep’t of Env’tl Protection to AQ Case File SOOP-63-00968, Re: Comment and Response Document, MarkWest Smith Compressor Station at 4 (Dec. 2020) [hereinafter DEP MarkWest Memo] (estimating facility’s potential to emit 2.08 tpy VOCs and 0.08 tpy HAPs from pigging), <https://ehb.courtapps.com/efile/documentViewer.php?documentID=48038> MarkWest Consent Decree, *supra*, at 22-23, app. 1, app. 3.

Commenter (0744-NYSDEC) is encouraged to see EPA considering requirements for pigging and blowdown activities in a potential supplemental proposal as it would result in both emissions reductions and public health benefits. The commenter notes that the state's regulation will include a notification threshold of 10,000 standard cubic feet (scf) for blowdowns and will require annual reporting of pigging activities. The commenter believes that a threshold of 10,000 scf for blowdown is sufficient to cover most blowdown events. Compressor stations, where these activities take place, may be located near populated areas and/or EJ communities. The commenter asserts that it is important that these communities are notified of blowdown activity in a timely manner. Blowdown events result in significant releases of methane and VOCs, which have a negative impact on public health.

Commenter (0832-NMED) asserts that pigging operations and related blowdown activities should be addressed in a supplemental proposal and encourages EPA to adopt requirements similar to New Mexico. The commenter proposed a comprehensive emission reduction and LDAR strategy for pigging operations in the proposed Part 50. Individual pipeline pig launcher and receiver operations with a potential to emit (PTE)  $\geq 1$  tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, are subject to the requirements of Part 50.

Commenter (1302-WYOC/PRBRC) suggests that there are opportunities to strengthen supplemental rules that the agency is considering in the future by addressing additional emission sources and ensuring that resources are being used efficiently to quickly prioritize and repair the most significant emission sources. The commenter specifically recommends that the future rule focus on reducing emissions from pigging and pipeline operations. The commenter notes that cleaning pipes through pigging operations can be a significant source of greenhouse gas emissions, and that there are existing technologies (such as installing multi-pig barrels and pump-down systems) that are already being used by some operators to reduce the frequency and intensity of venting during this common process. Similarly, the commenter asserts that future rules should eliminate the use of uncontrolled well blowdowns and require that these emissions be captured, used, or routed to combustors. The commenter notes that in areas like Wyoming's Upper Green River Basin, these blowdown events have been documented frequently as a major source of fugitive emissions and waste methane that have led to air quality concerns.<sup>91</sup>

Commenter (0918-COLGC ) supports a supplemental proposal that will provide proposed regulations for additional sources of pollution of methane and VOC emissions from the oil and natural gas sector. The commenter supports EPA proposing regulations to address pipeline "pigging" operations and pipeline blowdowns because effective technology currently exists to control emissions from these sources and several states have robust rules addressing emissions from these sources. The commenter asserts that the following state rules demonstrate the feasibility and cost effectiveness of requiring capture and control requirements to address venting from pigging and blowdowns and provide a blueprint for EPA to base a supplemental proposal to address emissions from these sources.

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<sup>91</sup> 5 CCR 1001-9, Part D, § II.H.3.f.

The commenter (0918-COLGC) notes that Colorado recently updated its rules related to pigging emissions and emissions from blowdowns. In Colorado, the commenter states that owners or operators must capture and recover gas from pigging and blowdown activities, and if not possible, must request approval to install and operate air pollution control equipment, such as vapor recovery, flare/combustors, or utilize an approved alternative to reduce hydrocarbon emissions.<sup>92</sup>

The commenter (0918-COLGC) reports that Colorado also requires the use of certain best practices to reduce either the need or frequency of pigging and blowdown events or reduce the emissions from those activities.<sup>93</sup> These include keeping pipeline access openings to the atmosphere on the pig receiver closed at all times except when a pig is being placed into or removed from the receiver or during active pipeline maintenance activities and where feasible for pipeline blowdowns other than for pigging operations, rerouting gas to the low-pressure system using existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems.<sup>94</sup> The rules also require creating or updating operating and maintenance plans to provide for the use, where practicable, of other best practices including using short pig barrels, where it reduces the gas volume for potential release; planning for venting-reduction steps, such as pipeline pump-downs techniques (*e.g.*, in-line compressors, portable compressors, ejector), when large vessels and pipelines need to be isolated and depressurized; minimizing the volume that must be released. For example, adding stops to isolate a smaller section of a pipeline to reduce the length of pipe that must be vented; using inert gases and pigs to perform pipeline purges; Hot tapping to make new connections to pipelines; coordinating operational repairs and routine maintenance to minimize the number of emissions events and volume.<sup>95</sup>

The commenter (0918-COLGC) notes that in its recent rulemaking, Colorado analyzed the costs of pigging and blowdown emission reductions. The state reported an average cost per ton of emission reductions of \$5,707.06 per tpy VOC and \$40.78 per mtCO<sub>2</sub>e/year. These costs, however, do not separate out pigging emissions or specific types of blowdowns (such as compressor blowdowns), but do exclude pipeline emissions which are subject to BMPs but not control requirements in the proposal.<sup>96</sup>

The commenter (0918-COLGC) reports that New Mexico is currently updating their rules for Ozone Precursor Pollutants in the Oil and Gas sector and has proposed rules for pig launching and receiving. Under the proposed rules, individual pipeline pig launcher and receiver operations with a PTE equal to or greater than 1 tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations would be subject to the proposed requirements. Under the proposed rules, owners and operators of affected pipeline

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<sup>92</sup> 5 CCR 1001-9, Part D, § II.H.3.f.

<sup>93</sup> 5 CCR 1001-9, Part D, § II.H.

<sup>94</sup> 5 CCR 1001-9, Part D, § II.H.4.

<sup>95</sup> 5 CCR 1001-9, Part D, § II.H.4.d.

<sup>96</sup> Colorado Air Quality Control Commission, Cost-Benefit Analysis, p. 32 (Dec. 3, 2021), [https://drive.google.com/drive/u/1/folders/1b9rQvQ4IZADyCGi-BD\\_rvOt6h3Xfyd0X](https://drive.google.com/drive/u/1/folders/1b9rQvQ4IZADyCGi-BD_rvOt6h3Xfyd0X).

pig launcher and receiver operations must capture and reduce VOC emissions from pigging operations by at least 95 percent within two years of the effective date of this Part. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98 percent. The owner or operator conducting an affected pig launching and receiving operation must also employ specified best management practices.<sup>97</sup>

The commenter (0918-COLGC) notes that in Pennsylvania, owners or operators that conduct pigging operations must employ best management practices to minimize the liquids present in the pig receiver chamber and to minimize emissions from the pig receiver chamber including, but not limited to, installing liquids ramps, installing liquids drain, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers. For pigging operations with a methane emission rate of 200 tpy or greater, or a VOC emission rate of 2.7 tpy or greater, or a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, after employing best management practices, the owner or operator must control methane, VOC, and HAP emissions from all pigging operations by at least 95 percent with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device, or any approved alternative method.<sup>98</sup>

Commenter (0776-CDPHE) provides details on Colorado's regulatory program for reducing emissions from pigging activities. The commenter notes that operational and maintenance activities in the midstream segment are the largest contributors of methane for midstream operations (other than from fuel combustion equipment), based upon data reported to the Air Division under Regulation 7 for 2020. The commenter contends that a number of studies and materials have documented that there are cost effective and technically feasible best practices to reduce these emissions.<sup>99</sup> The commenter provides that the Colorado's Air Commission adopted a rule in December 2021 addressing pigging and blowdown emissions at midstream operations.

The commenter (0776-CDPHE) reports that the Air Division consulted stakeholders and EPA enforcement officials to evaluate pigging operations<sup>100</sup> and analyze the potential for emission reductions, particularly methane reductions, throughout the segment. Colorado's rule covers pigging units at natural gas compressor stations, natural gas processing plants, and "stand alone

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<sup>97</sup> NMED Proposed 20.2.50 NMAC, Section 20.2.50.121 (Jan. 18, 2021, Version).

<sup>98</sup> Pennsylvania GP-5 Permit, Section K; Pennsylvania GP-5A Permit, Section K.

<sup>99</sup> See, e.g., Methane Guiding Principles, Reducing Methane Emissions: Best Practices Guide – Venting (Nov. 2019) (submitted herewith as Attachment 16); ZEVAC, Sales Sheet, Safely and quietly reduce emissions to ZERO with ZEVAC's patented vacuum and compression technology (submitted as Attachment 17 to the commenters' letter); Dominion Energy, Environmental Stewardship through Methane Emission Reduction (Feb. 19, 2021) (submitted herewith as Attachment 18); Summit Utilities, Colorado Natural Gas Innovates with Methane Recapture Technology (Jan 27, 2021) (submitted herewith as Attachment 19); EPA, Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities (June 1996) (submitted as Attachment 20 to the commenters' letter)

<sup>100</sup> Colorado defines "pigging" as the process pursuant to which a pig is used, unrelated to the purpose for which the activity is conducted. Reg. 7, Part D, Section II.A.31. The "pigging pipeline" is the length of pipeline along which the pig traveled during a particular pigging operation. Reg. 7, Part D, Section II.A.33. The "pigging unit" is the piece of equipment into which a pig is placed (pig launcher), and from which a pig is removed after traveling the pigging pipeline (pig receiver). Reg. 7, Part D, Section II.A.34. Pigging units release emissions during the process of placing and removing a pig. The "pigging facility" is the source at which the pigging unit is located (e.g., well production facility, standalone pigging station, compressor station, etc.). Reg. 7, Part D, Section II.A.32.

pigging stations.”<sup>101</sup> Through stakeholder engagement and consultation with government agencies, the commenter determined that there are a number of standalone pigging stations that are not located within the boundaries of natural gas compressor stations or natural gas processing plants, and that it was necessary to also address pigging at these stations.

The commenter (0776-CDPHE) states that Colorado’s rule requires most operators in the Denver-Julesburg (“DJ”) basin (where production includes a significant amount of hydrocarbon liquids) to employ a liquids management system. As a pig travels through the pigging pipeline, it pushes liquids into the pig receiver. These liquids must be appropriately handled. The commenter worked with stakeholders to ensure that these practices are designed to reduce the emissions from pigging operations by reducing the flashing of hydrocarbons entrained in the liquids when the pigging unit is opened to remove the pig.

The commenter (0776-CDPHE) states that Colorado also requires the capture of gas emitted during pigging.<sup>102</sup> Based upon consultation with EPA staff and stakeholders,<sup>103</sup> Colorado relies upon a matrix of the size and pressure of the pigging pipeline to determine applicability of capture requirements. Colorado determined that all pigging operations where the diameter of the pigging pipeline attached to the pigging unit is twelve (12) inches or greater and pigging operations where the pigging pipeline has a normal operating pressure over 500 pounds per square inch gauge (psig) must employ capture or control techniques.<sup>104</sup> For smaller size and lower pressure pigging pipelines, Colorado determined that an emissions-based threshold was an appropriate approach. These thresholds are based on the location of the pigging unit, and depend on the type of location, such as whether the unit is located in a disproportionately impacted community (more stringent thresholds apply to sources in disproportionately impacted communities). For both pigging and blowdown emissions, Colorado’s thresholds are based upon VOC and methane to capture pigging operations across the state where gas composition varies.<sup>105</sup>

Commenter (0458-MDE) recommends that EPA follow Maryland’s example of transparency and require the use of the internet to post large blowdown events. The commenter notes Maryland’s recent regulations for controls in the natural gas sector, final effective on November 16, 2020, can provide a basis for the commenter’s suggested improvements to the November 2021

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<sup>101</sup> Standalone pigging stations are “a pigging unit or group of co-located pigging units owned or operated by a midstream segment owner or operator but not located at a natural gas compressor station or natural gas processing plant.” Reg. 7, Part D, Section II.A.39.

<sup>102</sup> Colorado’s regulation also allows for operators to use control equipment in certain cases, but establishes a clear regulatory preference for capture of the gas. Colorado’s rules recognize that a minimal amount of gas will be emitted even after the use of required capture techniques. The emission of this residual gas is still considered effective capture.

<sup>103</sup> See Midstream Segment Data Collection - Blowdowns of Pigging Operations (Proposed Section II.H.) (submitted as Attachment 21 to the commenters’ letter).

<sup>104</sup> For newly constructed compressor stations, gas plants, and standalone pigging stations, gas emitted during pigging must be captured on all pigging units attached to pipelines with a normal operating pressure over 500 psig, regardless of the diameter size of the pipeline. Reg. 7, Part D, Section II.H.1.d and II.H.2.a.

<sup>105</sup> All emission calculations under this Section II.H - for both pigging operations and blowdowns - must be done pursuant to a Division-approved calculation method.

Proposal. The commenter generally supports federal rules, which better serve environmental protection and provide for industry certainty.

Commenter (0844-EDF *et al.*) recommends that EPA include proposed NSPS and EGs for pigging and blowdown activities on gathering pipelines in its supplemental proposal and consider proposing such standards for transmission pipelines as well. The commenter notes that pipeline pigging and blowdown activities are notable sources of methane, and technology and work practices are readily available to mitigate these emissions. The commenter agrees with EPA's identification of this issue in the November 2021 Proposal as an area of concern. The commenter asserts that because pigging and blowdown activities are similar on transmission lines, EPA should consider proposing NSPS and EGs for pigging and blowdown activities on transmission pipelines. The commenter provides the following details on methane releases and the prevalence of pigging and blowdowns.

The commenter (0844-EDF *et al.*) asserts that gathering pipelines have historically been subject to minimal federal oversight and are drawing increasing scrutiny as an environmental and safety concern. There are currently over 430,000 miles of onshore gas gathering lines in the United States,<sup>106</sup> yet EPA has never regulated pollution emissions from this equipment, although it has regulated associated gathering and boosting infrastructure in its oversight of methane emissions from gas production and processing. In 2020, the Pipeline and Hazardous Materials Safety Administration (PHMSA) regulated only 11,569 miles of onshore gas gathering lines, which are subject to reporting and leak survey and repair requirements.<sup>107</sup>

The commenter (0844-EDF *et al.*) states that the surge in domestic U.S. gas production since 2006 resulted in a significant expansion in the mileage of the gathering pipeline network and the volume of gas transported by gathering lines<sup>108</sup> Before 2006, gathering lines were generally smaller-diameter and lower pressure-pipelines that were “thought to pose relatively low risk to the public and the environment.”<sup>109</sup> But as industry expansion has placed increasing demand on this infrastructure, “[m]odern gas gathering lines often bear a closer resemblance to large interstate transmission lines than the diffuse network of small, low-pressure lines that previously characterized gathering lines.”<sup>110</sup> The commenter states that larger pipelines pose a greater risk of safety and environmental incidents and release higher volumes of methane during blowdown and pigging events.<sup>111</sup>

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<sup>106</sup> Highwood Emissions Management, Technical Report: Leak detection methods for natural gas gathering, transmission, and distribution pipelines at 13 (Jan. 12, 2022), <https://highwoodemissions.com/pipeline-report/>.

<sup>107</sup> PHMSA, Annual Report Mileage for Natural Gas Transmission & Gathering Systems, Year 2020 (last updated Jan. 4, 2022), <https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gastransmission-gathering-systems>.

<sup>108</sup> See U.S. Dep't of Trans., PHMSA, Final Rule: Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266, 63,267 (Nov. 15, 2021) (“Gathering Line Rule”).

<sup>109</sup> *Id.* at 63,266-67.

<sup>110</sup> *Id.* at 63,271.

<sup>111</sup> See M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 11 (June 2016), <http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf>

The commenter (0844-EDF *et al.*) notes that emissions from pipelines can be categorized as either fugitive emissions that result from leaks, or operational emissions that result from pigging, blowdowns, and other activities associated with operation of the pipeline. Recent surveys and research have found that gathering lines are a significant source of methane emissions, including super-emitting events. Airborne surveys in the Permian Basin across Texas and New Mexico found that about 30 facilities persistently emitted large volumes of methane over multiple years (2019-2021), and repairing those leaks could immediately reduce 100,000 metric tons of methane per year.<sup>112</sup> Nearly 20 percent of the persistent super-emitting leaks were from gathering pipelines.<sup>113</sup> While persistent emission points on gathering lines are likely attributable to pipeline leaks, intermittent methane super-emitter events have also been identified on gathering pipelines, and may be the result of pigging and blowdown activities.<sup>114</sup>

The commenter (0844-EDF *et al.*) states that blowdowns are conducted intermittently on natural gas pipelines for multiple reasons, including to conduct integrity inspections, clean a pipeline, or conduct repairs. Blowdowns conducted without mitigation practices can be significant emissions events, as all of the gas is evacuated from a segment of pipeline. A recent transmission pipeline blowdown by Kinder Morgan in Texas released approximately 25,000 dekatherms of methane as part of a road construction project, and the release was detected by a European Space Agency satellite.<sup>115</sup> Upstream of gas processing plants, blowdowns and pigging activities release not only methane, but significant amounts of other pollutants, including VOCs and HAPs.<sup>116</sup> Pipeline operators conduct blowdowns on all types of pipelines: gathering, transmission, and distribution pipelines. Although pigging activities are most common to clean gathering pipelines transporting unprocessed gas, they are also used on transmission and distribution lines—for example, smart pigs may be deployed in any type of pipeline for integrity management, to identify stress, corrosion, and leaks.<sup>117</sup>

Commenter (0844-EDF *et al.*) notes that EPA states in the November 2021 Proposal that through the 2019 Greenhouse Gas Reporting Program (GHGRP), operators reported “472,995 total individual blowdown events from 1,212 facilities for a combined 307,630 metric tons of methane emitted, including 79,746 events at pig launchers or receivers for a combined total of 19,066 metric tons of methane.” The commenter adds that EPA acknowledges that the GHGRP data only includes emissions from blowdown equipment with a “unique physical volume greater than 50 cubic feet and occurring at a facility with total emissions greater than 25,000 metric tons

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<sup>112</sup> EDF & Carbon Mapper, Press Release: Dozens of “super-emitting” oil and gas facilities leaked methane pollution in Permian Basin for years on end (Jan. 24, 2022), <https://www.edf.org/media/dozens-super-emitting-oiland-gas-facilities-leaked-methane-pollution-permian-basin-years-end>.

<sup>113</sup> *Id.*; see also Cusworth *et al.*, Intermittency of Large Methane Emitters in the Permian Basin, *Environ. Sci. Technol. Lett.* 2021, 8, 7, 567–573 (June 2, 2021), <https://doi.org/10.1021/acs.estlett.1c00173>.

<sup>114</sup> See Cusworth *et al.*, Intermittency of Large Methane Emitters in the Permian Basin, *Environ. Sci. Technol. Lett.* 2021, 8, 7, 567–573 (June 2, 2021), <https://doi.org/10.1021/acs.estlett.1c00173>.

<sup>115</sup> Naureen S Malik & Aaron Clark, How a Rural Texas Road Project Triggered a Cloud of Methane, *Bloomberg* (Dec. 1, 2021), <https://www.bloomberg.com/news/articles/2021-12-01/this-rural-texas-road-project-triggered-a-cloud-of-methane>.

<sup>116</sup> *Supra* Section II.I.

<sup>117</sup> See Proposal at p 63,242; see also Page Leggett, How smart PIGs keep pipelines safe, *Duke Energy Illumination* (Jan. 6, 2017) (explaining that Piedmont Natural Gas uses cleaning pigs and smart pigs to inspect “hundreds of miles of transmission pipelines each year”), <https://illumination.duke-energy.com/articles/how-smart-pigs-keep-pipelines-safe>.



CO<sub>2e</sub>.” The commenter suggests that, because there may be blowdown events on gathering lines below the EPA reporting threshold, it is likely that EPA’s data underreports the true extent of emissions from these events. Furthermore, small gathering line operators “are less likely to have data on the characteristics of their gathering lines readily available,” and that “data on the characteristics of older gathering lines are less likely to exist than for newer pipelines.”<sup>118</sup> For this reason also, the commenter believes that pipeline operators reporting to the GHGRP may provide data that underestimates the actual emissions resulting from blowdowns.

Commenter (0844-EDF *et al.*) states that the blowdown emissions EPA describes in the November 2021 Proposal appear to be limited to gathering lines, but similar activities occur on transmission and distribution pipelines and cause significant emissions. The commenter notes that EPA quantifies methane emissions from pipeline blowdowns under the following categories in the GHGI and presents a table presenting GHGI emissions: [see TABLE in commenters’ letter: Methane Emissions from Pipeline Blowdowns, 2019 lists the CH<sub>4</sub> emissions in kt from Production-G&B Pipeline Blowdowns (31.5), Transmission-Pipeline Venting (199.4), Distribution-Pipeline Blowdown (4.4), and Total (235.3) <sup>119</sup>]

### ***18.2.3 Specific Pigging Operation/Blowdown Requirement Considerations***

Commenter (0808-API) recommends that EPA focus on reducing emissions volumes associated with pigging operations, allowing facilities to implement necessary emission reduction alternatives that are most appropriate as each location has a different set of circumstances for its operations. The commenter notes, as mentioned by EPA, that there are several alternatives for reducing the various emissions from pigging operations. Some alternatives might be appropriate for broad application and other alternatives could require unreasonable cost and infrastructure modification for minimal emissions reductions. Existing programs and practices already implemented by operators also need to be considered. There is a distinction in the feasibility of capturing and controlling pigging emissions from those pig launchers and receivers co-located at a compressor station or gas plant as compared to remote launcher and receiver locations where supporting infrastructure (*i.e.*, electrical power, line jumpers to low pressure pipelines, flares, etc.) does not exist.

The commenter (0808-API) provides examples of how emissions from a pig launcher or receiver can vary widely. Emissions from a pig launcher or pig receiver occur primarily from opening the isolated pig barrel (and often a short distance of piping connected to the pig barrel) to either insert or remove a pig. The emissions are from the natural gas inside this isolated area when the pig barrel is opened, which is typically called a “blowdown.” When a pig receiver is opened, there may be some residual liquids in the receiver, primarily from liquid falling off the pig itself. The commenter notes that the volume of liquids in the receiver is unrelated to the amount of

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<sup>118</sup> U.S. Gov’t Accountability Office, Operators of Natural Gas and Hazardous Liquid Gathering Lines Face Data Collection Challenges at 9, 10, Report No. GAO-22-104817 (Jan. 2022), <https://www.gao.gov/assets/gao-22-104817.pdf>.

<sup>119</sup> U.S. EPA, Natural Gas and Petroleum Systems in the GHG Inventory: Additional Information on the 1990-2019 GHG Inventor, Annex 3.6: Methodology for Estimating CH<sub>4</sub>, CO<sub>2</sub>, and N<sub>2</sub>O Emissions from Petroleum Systems (published Apr. 2021), <https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg>.

liquid a pig pushes down a pipeline. This limited amount of liquid in the receiver may have the potential for minimal flash emissions and perhaps volatilization.

The commenter (0808-API) explains that emissions from pig launchers and receivers vary widely based on several different, and sometimes interrelated factors: the diameter of the pig barrel and connecting midstream gathering pipeline; the length of the barrel or portion of the midstream gathering pipeline in between the pigging unit isolation valves; the pressure and composition of the gas within the unit; pig launching or receiving frequency; and the amount of liquids accumulation (applicable to receivers only). Consequently, frequency of pigging operations alone is not a good proxy for actual emissions as it is just one element that informs emissions. As a result, the commenter states that, if one were to compare two pig launchers that are each used once per month, where the temperature is the same and the gas composition is the same, but the barrels have different diameters and lengths and different pressures, the actual emissions—calculated using the ideal gas law—from the two launchers would not be equal, potentially by a wide margin.

Commenter (0755-Texas Pipeline Association (TPA)) urges EPA to allow operational flexibility in technology and avoid overly prescriptive requirements in any pigging operations regulations. In the area of pigging operations, there is no one-size-fits-all approach; the most effective, efficient, and environmentally sound procedure will vary greatly from site to site and is highly dependent on each individual site's particular characteristics. If any standard is implemented, the commenter recommends that it be one that sets a goal and leaves it to individual regulated entities as to how that goal is to be achieved. The commenter states that overly prescriptive standards are inadvisable for the additional reason that reduction of emissions in pigging operations is an emerging field with new technology being developed on an ongoing basis. A top-down prescriptive approach, *i.e.*, a rule that does not just say what the goal is but goes on to dictate how that goal must be achieved, would run the risk of stifling, if not altogether killing, the innovation that is currently underway as companies and consultants develop innovative and varied ways to reduce pigging emissions. The commenter recommends that EPA allow such emerging innovation to flourish.

Commenters (0599-MSA, 0817-GPA) recommend that any requirements be technology-neutral. If EPA determines that emissions controls are required for pigging operations, the commenter asserts that specific methods should not be mandated because of the differences in equipment and pipelines on which they are used (*e.g.*, diameter, pressure, available space). Each potential control method has limitations depending upon the specific application.

Commenter (0831-AXPC) states that, similar to upstream operations, it is important that any regulation of pipeline “pigging” operations provide for operational flexibility in technology and approach.

Commenter (0585-KOGA) understands EPA’s mission and wishes to support common sense and economically viable solutions to enhance emission reduction. The commenter provides pipeline operations details for consideration.

The commenter (0585-KOGA) states that pipeline operations differ considerably by product transported and geography. Natural gas is produced throughout the U.S. from varying plays and with that the constituents of the raw product ranges from very saturated to very dry, resulting in a wide array of configurations and operational requirements to manage pipeline gas quality concerns.

The commenter (0585-KOGA) explains that the frequency of pigging varies greatly and the necessity to complete pigging activates ranges from operational purposes to regulatory required options to support overall integrity of pipe systems. Although pigging valves are an excellent option for operational pigging those facilities typically are not viable when completing internal inspection utilizing “smart” devices.

*Multi-pig launcher systems:* The commenter (0585-KOGA) asserts that these systems are a valuable tool for operators of larger diameter pipes and systems that require pigging on a frequent basis. However, application of this type of device would require significant modifications and equipment upgrade from small operators who frequently pig smaller diameter and low volume pipes for operational fluid removal. Those existing pigging facilities are typically smaller in diameter and contain less volume by function and design.

*Liquids Management:* The commenter (0585-KOGA) generally supports guidance regarding pigging facility design allowing for fluid to be drained from the bottom portion of the facility. Many pigging facilities already have this design and retrofitting existing facilities for future compliance would be manageable.

The commenter (0585-KOGA) provides that the installation of a ramp to allow for free draining of potential liquids entrapped by pigging devices inside of the receiver barrel seems unnecessary as receiver barrels are typically designed with larger diameters than the pipeline facility thus allowing room around the pigging device for fluid draining. Similarly, the installation of impermeable membranes would be excessive providing appropriate drain line installation. Certainly, the utilization of absorbent pads or similar devices placed at the entrance door opening would be a viable alternative to recover any minor amounts of fluids experienced during post pigging assembly entrance. The commenter (0585-KOGA) does not want to create an unsafe situation by adding absorbent pads and requiring their employees to handle the pads.

The commenter (0585-KOGA) believes that installation of jumpers between facilities is a viable method to transition from high to lower pressure or volume facilities during planned maintenance activities. Providing those facilities are of like maximum pressure thresholds and consideration can be made to protect the established design Maximum Allowable Operating Pressure/Maximum Operating Pressure. However, the commenter reports that many operators may not have ability to complete this activity due to system configurations or upstream and downstream sensitive customer load demands.

*Utilizing barrel pump devices:* fixed or portable compression or pump devices are becoming more widely available; however, the commenter (0585-KOGA) states that a similar affect can be achieved utilizing the jumper method for depressurization and volume transfer where system configurations permit. Operators of smaller diameter, low volume facilities may find the capital

purchasing, training, and potential qualifications for personnel to utilize these types of device an uneconomic option.

Commenters (0599-MS, 0817-GPA) assert that EPA should not impose control options for pig launcher and pig receiver blowdowns. The commenters explain that methods to reduce emissions from pig launchers and pig receivers are continuing to emerge, and the commenter urges EPA not to stifle innovation by mandating prescriptive requirements. In addition, the commenters note that there are limitations with these methods—there is no “one size fits all” solution. As such, if EPA develops a proposal, the commenters recommend that EPA limit any requirements to documentation of work practices employed to reduce emissions rather than mandate which work practices must be used. In addition, the commenters believe that EPA should not mandate certain emission reduction percentages, as doing so would preclude the use of certain methods (*i.e.*, a 95 percent control requirement may preclude the use of barrel pump down systems as described below). The commenters note that a reduction percentage requirement would also force operators to record theoretical emissions (*i.e.*, if a multi-pig launcher is used, would operators record the theoretical emissions of a traditional pig launcher?).

The commenters (0599-MS, 0817-GPA) provide comments about six methods to reduce or control blowdown emissions from pig launchers and pig receivers:

1. *Multi-Pig Launcher Systems.* The commenters state that multi-pig launcher systems are not an appropriate emissions reduction system. The commenters recommend that EPA not consider mandating multi-pig launchers as an appropriate system for emission reduction. The commenters note that the EPA’s statement that it “understands that multi-pig launchers and receivers are most appropriate for large diameter pipelines,” 86 Fed. Reg. at 63,243, is somewhat oversimplified and should not be the foundation for regulatory requirements. Multi-pig barrels may refer to a specific technology where multiple pigs can be loaded into a launcher apparatus (usually accompanied by a multi-pig receiver). The use of such multi-pig launchers and receivers is usually dictated by the frequency of pigging. For example, the commenters provide that a multi-pig launcher that can accommodate seven pigs may be used when a pipeline must be pigged every day, and the downstream pig receiver is sized to hold seven pigs. Once a week, the pig receiver would be opened to retrieve the pigs, and the pigs would be loaded into the pig launcher. Or a multi-pig launcher may send multiple pigs a day. However, if pigging frequency is expected to decline rapidly over time (*e.g.*, from daily to monthly), pigs may be pulled per pigging event, and the larger multi-pig systems could have larger emissions per pigging event. Multi-pig systems are expensive, costing approximately \$1 million per system for a 16-inch pipeline.

Longer pig receiver barrels may also be referred to as “multi-pig barrels” because they could theoretically accommodate multiple pigs. These longer barrels are usually installed where “smart pigs” are used for pipeline inspections. However, in practice, the commenters report that most operators remove each pig as it is received to ensure all pigs are accounted for (*i.e.*, to ensure the pig isn’t stuck in the pipeline).

2. *Pig Ball Valves.* The commenters state that pig ball valves should not be considered valid

control devices as they are not commonly used. The apparatus tends to have many small crevices where liquids can get trapped and freeze. Further, where pig launchers and pig receivers operate close to production sites, debris (such as sand) in the pipeline fluid can damage the valve seals. In either case, the entire pipeline to the nearest upstream and downstream isolation valves must be blown down to repair the pig ball valve.

The commenters report that the cost of a pig ball valve varies by pipeline size, but operators report costs ranging from \$15,000 to \$60,000, which depends on the size of the pipeline. Generally, these are only cost effective for pipelines six inches or less in diameter. Further, should the pig ball valve need maintenance, to avoid blowing down the entire pipeline and creating a significant emissions event, operators may install isolation valves on either side of the pig ball valve, however, this significantly adds to the cost. Pig ball valves are best suited when physical space is too small to accommodate a traditional pig launcher or pig receiver.

The commenters add that another drawback is that some pig ball valves require the use of a specific manufacturer's pig or one of a particular type. This reduces operational flexibility and may add to costs. Notably, pig ball valves are not compatible with smart pigs. Therefore, operators may have to use both a pig ball valve and a traditional pig launcher or pig receiver to use smart pigs. This obviously involves increased costs.

3. *Jumper Lines.* The commenters recommend that jumper lines not be mandated due to their limited use. Jumper lines (which the commenter understands to be temporary or permanent hosing or piping) to route gas from a high-pressure system to a lower pressure system should not be mandated, as they are limited to pig launchers and pig receivers operating at higher pressure that are physically near to a low-pressure system, such as a low-pressure pipeline. The commenters estimate that jumper lines are only feasible for less than 5 percent of pig launchers and pig receivers.

The commenters add that jumper lines raise safety concerns due to the need to route higher pressure gas to a lower pressure system (including pipelines that are only rated to operate safely up to a certain pressure). Over-pressurization is a significant risk, so the use of jumper lines necessitates very specific operating procedures and, ideally, engineering "backstops" such as a rupture pin valve, to prevent over-pressurization.

Additionally, the commenters report that a low-pressure system would need to also provide some place for the gas to go or be used, which may not be available. For example, a fuel gas system at a compressor station is a low-pressure system, but only so much fuel is consumed. As a practical matter, the pressure "draw down" rate would be set according to the capacity of the low-pressure system to move or consume the gas.

According to the commenters, installing a low-pressure blowdown system at a facility would cost around \$100,000. One operator reports connecting three separate high-pressure pig barrels to low pressure lines that were 250 feet away at a cost of approximately \$35,000 (this included a hot tap, which was necessary to have a tie in point to the low-pressure system).

Further, the commenters add that EPA states that “[g]ases that remain in high pressure barrels after venting to low pressure systems, and gases in low pressure barrels, can be recovered during depressurization by discharging the gases to very low-pressure systems at the site (e.g., 10–15 psig).” 86 Fed. Reg. at 63,245. But some operators have vapor recovery unit (VRU) lower pressure suction shutdowns at 25 psig. Therefore, the commenter recommends that EPA not assume the pressure at which low pressure systems operate. Additionally, where VRUs are not available, low pressure gathering lines will act as the low-pressure system, and the pressure of these lines vary and more typically range from 40 psig to 200 psig.

4. *Barrel Pump Down Systems.* The commenters assert that barrel pump-down systems are a costly investment without the recovery that EPA assumes. The commenters state that in a pump-down system, the pig launcher or pig receiver is isolated from the main pipeline by closing the isolation valves. Once isolated, the launcher or receiver is connected by (an often temporary) pipe or hose to the pump down unit, which is then connected by (an often temporary) pipe or hose to the main pipeline. The pipe/hose and the pump down unit may need to be cleared of oxygen before they are put into service so some of the vapor in the isolated pig launcher or pig receiver is used to purge the pipe/hose and pump down unit. The remaining gas in the pig launcher or pig receiver is routed to the main pipeline. The pump down unit reduces the pressure of the isolated launcher or receiver to the lowest pressure allowable for the pump down unit (e.g., 5 psi). The gas remaining in the isolated pig launcher or pig receiver at this low pressure is blown down to atmosphere. The gas remaining in the piping/hosing and pump down unit are also released to atmosphere upon disconnecting the piping/hosing and pump down unit from the pig launcher or pig receiver.

The commenters add that some pump-down units are driven by an air compressor. The air compressor is driven by a diesel engine, truck engine, or electricity, if available. The commenters states that EPA’s claim that pump-down units recover greater than 99 percent of the depressurization vapors from pig launchers and pig receivers does not appear to account for purging the pipe/hose and pump down unit prior to commissioning, residual gas in the pig launcher or pig receiver once the lowest pressure is achieved, disconnecting the piping/hosing and pump down unit, and emissions from a generator or truck engine to drive the air compressor. The percent control achievable is largely a function of the pressure of the gas in the pig launcher and pig receiver after isolation, which is a function of the operations of that pipeline.

The commenters report that pump-down systems cost approximately \$500,000, excluding the cost of personnel to operate the equipment. According to the commenters, this can be significant because using these systems takes much longer than a blowdown, so operators would need to add staff to account for this additional time.

5. *Low-Capacity Combustion Devices.* The commenters state that low-capacity combustion devices are not appropriate control measures. The commenters note that temporary flares are generally not designed for a high pressure blow down that may contain some liquids, and this can cause smoking. Smoking can be reduced by assist air or gas but that is often

unavailable or infeasible at remote locations. The commenter is concerned that temporary flares do not meet NSPS control device requirements.

Where liquids are present, the commenters state that operators would need to employ a liquid knock out system and then manage those liquids. This would require two trailers at the site—a flare trailer and knockout skid trailer. Additionally, flares are designed for certain operations and services. A flare designed to combust gas from a low-pressure pig launcher or pig receiver would not be appropriate to combust gas from a high-pressure pig launcher or pig receiver; thus, operators may need to purchase multiple flares.

The commenters add that significant planning and coordination are required to use temporary flares safely and within the often-cramped confines of the right-of-way. Erecting trailer-mounted combustors many times a day throughout the field is simply an unacceptable safety hazard while permanent combustion devices at remote locations would be both economically infeasible and would likely be opposed by the public.

6. *Short” Pig Barrels.* The commenters assert that other technologies such as “short” pig barrels present issues and should not be mandated. The commenters oppose any regulation pertaining to the use of “short” pig barrels because these preclude the use of multi-pig launchers which may be better technologies for reducing emissions at certain operations. Also, the commenters note that short pig barrels may not accommodate smart pigs without the construction of duplicate pigging systems. The commenters’ statement is in response to EPA’s request for comment regarding other pigging operations technologies, and the commenter’s consideration of technologies and work practices included in consent decrees or state rules.

The commenters (0599-MS, 0817-GPA) recommend that EPA not mandate potential control options for pig receiver liquids management and present details regarding liquids management methods that are presented below.

The commenters (0599-MS, 0817-GPA) note that most liquids pushed by the pig either continue down the pipeline (if the pig receiver is not at a compressor station or gas plant) or are collected in a vessel such as a slug catcher (if the pig receiver is at a compressor station or gas plant). In other words, most of the liquids that are pushed by the pig are not retained in the pig receiver. Additionally, regarding work practices for managing pig receiver liquids, after the pig reaches the receiver, gas continues to flow through the receiver until the operator isolates it from the main pipeline. This provides a sweep of gas that also removes some residual liquids from the receivers. The commenters report that many operators restrict gas flow through the main line to push additional gas through the receiver and provide an additional “sweep” prior to isolation. The commenters assert that this work practice already assists greatly in liquids management. The commenters offer three points regarding liquids management:

1. *The commenters recommend that EPA not mandate condensate drain lines.* Liquids that drop out in a pipeline are pushed ahead by a pig (or pigs) for recovery. Some pig receivers have condensate drains connected to the main pipeline. When the drain line is open, gas pushes the residual liquids in the receiver to the pipeline. The drain line must

return to the pipeline at a lower elevation (often underground) than the pig receiver to create the necessary differential pressure. Although condensate drains are commonly used, compliance mandates would not be possible in all operating conditions/facilities. For example, cold weather has presented problems in certain regions and those operators cannot—and do not—install condensate drains due to freezing in the winter.

Even for those operators that can comply, the commenters state that retrofitting is a substantial effort. The process would likely require excavation to connect the line to the main pipeline, in addition to other requirements, and would be costly (\$30,000–\$75,000 depending on if a hot tap is required) and may trigger other regulatory or permitting requirements. According to the commenters, mandating condensate drain lines for existing pig receivers is, therefore, not appropriate.

2. *The commenters recommend that EPA not mandate pig ramps as they offer limited benefits and present safety risks.* A pig ramp is a structure built into a pig receiver barrel that slightly elevates the received pig to allow liquids to flow back to the barrel drain (if a drain is present). Liquids on the pig itself may also drain off. There is a small “lip” on the pig ramp near the door which may retain some liquids within the barrel. Pig ramps do not eliminate liquids in the receiver barrel; they only route them to drains.

The commenters add that pig ramps provide limited VOC and methane emission benefits. Draining the small amount of residual liquids may avoid some flash emissions or volatilization. Depending on liquid volume, liquid composition, and how well liquids are currently managed by nature of the pig receiver design, pig ramps may or may not be cost effective. Pig ramps are not commercially manufactured and require fabrication shop construction. The commenters are aware of only one operator using pig ramps and that is only due to a consent decree requirement. The commenters estimate that a pig ramp could cost \$1,000 to \$4,000, depending upon the pipeline diameter. This is based on the sole operator who has fabricated pig ramps and fabrication shop quotes from other operators.

According to the commenters, there are risks involved with using a pig ramp. The ramp must be affixed firmly because there is a risk of spark and explosion with metal-on-metal movement. Using plastic materials is not feasible. In certain circumstances, the barrel must be removed or purged with nitrogen during installation to mitigate explosion risk. The ramp cannot be present for “smart pigging” in all circumstances, requiring the installation of a temporary barrel. Ramps also increase crevice corrosion. This increases costs from inspection and replacement of certain components of the pig receiver. Unless installation and pigging schedules are very closely coordinated, especially for infrequently used pig receivers, installing pig ramps will necessitate an additional blowdown that would not otherwise occur. Because emissions from pig receiver blowdowns may be higher than emissions avoided, it is possible that pig ramp installation will increase emissions.<sup>120</sup>

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<sup>120</sup> See Exhibit 1, Excerpt of the Joint Prehearing Statement of the Colorado Oil & Gas Association and American Petroleum Institute Colorado Before the Colorado Air Quality Control Commission In the Matter of Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 7 and Regulation Number 22.



3. *The commenters state that enhanced liquid containment is not a workable option.* For field pig receivers, enhanced containment would require the operator to attach an impermeable cover over the catch basin after the pig liquids are removed. However, the commenters believe this is unworkable with little to no benefit. Residual hydrocarbon liquids in the pig receiver would begin to flash immediately upon opening the receive door. Even if flashing is not complete after the liquids are emptied to the catch basin, both the catch basin and impermeable lid would have to be pressure-containing and operators would have to develop a process to eliminate liquids and flashed vapors without emissions. The commenters are not aware of any real-world configurations like this.

At some compressor stations and natural gas plants, a system along these lines would include condensate drains on a pig receiver to a downstream pressurized “slug catcher” vessel. The vapor recovery unit on the vessel would route the vapors to the facility inlet. Liquids in the slug catcher would be managed with other liquids at the facility. The commenters report that there could be variations on this design, but it is a robust and complex engineering solution.

The commenters note that some operators have lids that slide over pig receiver liquid troughs, but these are used to prevent rainwater from entering the trough.

Commenters (0599-MS, 0817-GPA) recommend that, as EPA established with storage vessels, any control or work practice requirements developed should only apply to pigging operations that exceed an emission threshold, such as 1 tpy VOC, because the control scenarios will be costly to implement. The commenters believe this to be especially true at existing sources. The commenters contend that providing an emission threshold will also encourage operators to develop innovative engineering solutions that will avoid or prevent emissions from occurring.

Similarly, commenter (0755-TPA) recommends that EPA recognize that the scope and level of emissions varies greatly from one pigging operation and the next, and therefore it is reasonable for any new standard to contain applicability thresholds expressed in emissions amounts, measured at each individual receiver or launcher, to exclude those sources and operations that are not resulting in significant emissions. The commenter notes that in many cases the emissions from a launcher or receiver can be *de minimus*, while a more extensive operation at an upstream location could result in higher emissions. The commenter asserts that in keeping with other provisions in the NSPS, an applicability threshold is a reasonable and fair way to avoid undue burden on small sources and further avoid imposing requirements that do not meet a reasonable cost versus environmental benefit standard. The commenter states that an applicability threshold would have the additional benefit of incentivizing owners and operators to find ways to reduce emissions, to keep emissions below applicability levels.

Commenters (0599-MS, 0817-GPA) recommend that EPA only consider proposed language regarding the control of pigging emissions for new facility construction due to the significant capital required to add or modify or retrofit existing control devices.

Commenter (0755-TPA) recommends that EPA requirements on pipeline blowdowns should only apply to large blowdowns, as supported by a reasonable cost-benefit analysis in this area. The cost of reducing blowdown emissions can be substantial, as the effort would generally include procurement, installation, and operation of recovery or combustion control equipment such as pump down systems or temporary combustion devices. Installation of such equipment should not be required in the context of small blowdowns producing minimal emissions. Thus, any regulatory limits in this area should contain an exclusion for small blowdowns creating minimal emissions.

Commenters (0599-MSD, 0817-GPA) suggest that if regulations are developed, they apply based on a per event threshold and be limited to planned, non-emergency blowdown events.

Commenter (0789-PADEP) recommends that EPA review and consider the Consent Decree between EPA and Pennsylvania Department of Environmental Protection with Mark West Liberty Midstream & Resources, LLC and Ohio Gathering Company, LLC. The commenter notes that the consent decree requires installation of enclosed flares at select compressor stations and implementation of certain best management practices when conducting pigging operations, among other controls, that may be appropriate to incorporate in the proposed rule.

Commenter (0809-Earthjustice) states that EPA has a great deal of readily available information regarding the implementation, costs, feasibility, and emission reductions of pig launchers and receivers potential control options. The commenter notes that as part of its 2018 consent decree, EPA required the installation and operation of “pig-ramps” and “jumper lines” at existing and new pig launchers and receivers in Pennsylvania and Ohio.<sup>121</sup> The commenter adds that EPA also required MarkWest to “disseminate and make available for use by other oil and gas companies its proprietary design for Pig Ramps” and to educate other operators on the installation and use of pig ramps and jumper lines.<sup>122</sup>

Commenter (0944-Kuva Systems) reports that at sites with continuous OGI camera installations, emissions from pigging operations can be detected, recorded and quantified. This information may be used for checking compliance, and for training purposes to improve operational practices to minimize emissions. The commenter believes that C-OGI cameras are particularly suitable for this task as they generate images with color overlay of emissions that are easily understandable by operations staff and much more likely to result in behavioral change training with then non-visual tools. Moreover, the commenter adds that such information may be collected without incremental cost at sites where C-OGI cameras are installed for other reasons.

Commenter (0844-EDF *et al.*) provides details on technology and work practices that are readily available mitigation practices that can limit emissions from blowdown and pigging events. The commenter recommends that EPA consider these and all other potential options as it considers a supplemental proposal to address methane emissions from blowdown and pigging activities on pipelines.

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<sup>121</sup> See MarkWest Consent Decree, *supra*, at 10-14.

<sup>122</sup> *Id.* at 16-17.

The commenter (0844-EDF *et al.*) notes that the November 2021 Proposal documents multiple proven technologies and practices that are available to reduce blowdown and pigging emissions, focusing on jumper lines, vapor recovery units or other fuel gas systems, small compressors (barrel pump-down systems), and flares. As discussed in a report by M.J. Bradley & Associates, the commenter reports that these kinds of mitigation technologies and practices can reduce methane emissions from gas pipeline blowdown by up to 90 percent.<sup>123</sup> The M.J. Bradley report details five mitigation options, four of which are also identified in EPA's November 2021 Proposal: pressure reduction with in-line compressors, pressure reduction with mobile compressors, transfer of gas to a low-pressure system, isolating a small pipeline section with stopples, and flaring. The report provides detailed cost and man-hour estimates for each mitigation option,<sup>124</sup> summarized in a table presented in their comment letter.

[See Table 6, Costs and Benefits of Blowdown Mitigation Options, lists the Interstate and Intrastate Costs (\$/event), Methane Reduction (MT/event), and Average Cost (\$/MT)]

The commenter (0844-EDF *et al.*) reports that the data show that all of these measures are highly cost-effective, and in most cases, one to two orders of magnitude lower than values that EPA has in the past defined as cost-effective for methane controls. However, consistent with the commenter's recommendations in these comments for other sources, they note that flaring is a decidedly inferior control strategy from both environmental and waste perspectives and should only be permitted as a means of avoiding venting during blowdown and pigging events when all other options are either truly unavailable or would present safety concerns. Furthermore, the commenter notes that the documentation of successful blowdown emissions mitigation efforts indicates the value of specific and detailed work practices. Operators must normalize and incorporate work practices into their regular operations so that consideration of methane abatement is part of the job. Below, the commenter describes some of the work practices (some of which overlap with the measures identified in the M.J. Bradley report) that can successfully curb emissions from pipeline blowdown and pigging events.

*California Gas Utility Methane Abatement Practices.* California law SB1371, enacted 2014, requires natural gas utilities to minimize methane emissions from the transmission and distribution systems. The California Public Utilities Commission approved a gas leak abatement program as part of SB1371 implementation, adopting 26 mandatory Best Practices ("BPs") for minimizing methane emissions that include multiple provisions to reduce blowdown emissions<sup>125</sup> These BPs, which could also help to reduce emissions from pigging activities, include the following:<sup>126</sup>

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<sup>123</sup> M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 14 (June 2016), <http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf>.

<sup>124</sup> *Id.* at 14-20. The report also quantifies the benefits of each mitigation option based on the economic and social value of saved gas, but these values may no longer reflect the most recent and accurate Social Cost of Carbon and Social Cost of Methane values.

<sup>125</sup> California Public Utilities Commission, Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371, Decision 17-06-015, Appendix B: Best Practices for Natural Gas Leak Abatement Program (June 15, 2017).

<sup>126</sup> *Id.* at B5-B6, B14-B15.

- BP23, Minimize Emissions from Operations, Maintenance and Other Activities. – “Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (*i.e.*, no-bleed) or vents significantly less natural gas (*i.e.*, low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.”
- BP5, Methane Evacuation Procedures. – Utilities shall establish “[w]ritten company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.”
- BP6, Methane Evacuation Work Orders Policy. – Utilities shall establish a “[w]ritten company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers.”
- BP7, Bundling Work Policy. – Utilities shall establish a “[w]ritten company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable.”

Commenter (0844-EDF *et al.*) provides that the California gas utility Pacific Gas & Electric Company (PG&E) has documented in detail the implementation of practices to minimize blowdown emissions in its Leak Abatement Compliance Plan, as required by SB1371.<sup>127</sup> The company reported that “[f]or non-emergency gas transmission pipeline blowdowns, PG&E abated approximately 80 percent of the total gas volume released from its transmission pipeline projects through drafting and cross compression.”<sup>128</sup> The breakdown of these emission reductions is presented in a table. [Per Table in comment letter: PG&E 2018 Transmission Pipeline and Regulator Station Abatement Activities details Total Gas Volume (Mscf) per Pipeline Activity type; Drafting (119,833), Cross Compression (504,320), Blowdown (159,215), Total Gas Baseline (783,372), Percent Gas Diverted to Drafting or Cross Compression (80 percent)]

The commenter (0844-EDF *et al.*) reports that to reduce methane emissions during non-emergency blowdowns, PG&E developed a new standard and procedure, TD-5601S and TD-5601P-01. The new standard provides numerous directives, including to “[s]chedule all planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including project bundling, drafting, cross compressing and flaring.”<sup>129</sup> The commenter adds that the company’s Plan also identifies numerous next steps that it will

<sup>127</sup> PG&E, 2020 Leak Abatement Compliance Plan (submitted Mar. 16, 2020; amended Oct. 19, 2020) .

<sup>128</sup> Id. at 1-1.

<sup>129</sup> Id. at 1-13, 1-55, 1-61.

undertake to improve on its existing best practices for blowdowns, suggesting that further methane emissions mitigation can be achieved. For example, the company describes a goal to purchase additional trailers with mobile compressors so that multiple compression jobs can proceed simultaneously; to investigate purchasing a “gas-driven mobile fill compressor and tube trailers . . . to use mobile compression” to reduce emissions from smaller blowdowns or pipelines that do not have a nearby pipeline to cross-compress into; and to “[e]xplore the applicability and feasibility of using multi-stage/boost compressors to further reduce the amount of gas released during backbone pipeline blowdowns.”<sup>130</sup>

The commenter (0844-EDF *et al.*) states that additionally, the company is evaluating new technology to replace flaring by catalytically oxidizing methane, through a pilot project with Stanford University and NYSEARCH.<sup>131</sup> The company is exploring other technologies to reduce blowdown emissions:

PG&E plans to explore the use of ZEVAC technology in gas operation activities. ZEVAC uses compressed air to eliminate emissions. The compressed air is used to suction the pipeline segment and compresses the gas into an adjacent pipeline or tank. The intake could then be discharged back into the system. ZEVAC technology will be assessed for use in reducing emissions from non-emergency blowdowns and has the potential to further reduce emissions from non-emergency blowdowns.<sup>132</sup>

*Methane Guiding Principles.* The Methane Guiding Principles (MGP) is a voluntary, international partnership that has issued detailed best practices to reduce methane emissions along the natural gas supply chain, developed by a coalition of industry and civil society organizations.<sup>133</sup> The commenter (0844-EDF *et al.*) explains that MGP includes best practices to reduce methane emissions from pipeline pigging and blowdown activities.

The commenter (0844-EDF *et al.*) reports that regarding pigging, the MGP recommends the use of pig ramps and jumper lines to reduce emissions during the insertion and removal of a pig from a pipeline. The operating requirements include “extra time . . . from the pig being received to it being removed from the receiver to allow the liquids to drain back to the pipeline,” as well as a low-pressure system “available on-site to accept the gas from the pig trap.”<sup>134</sup> The guide reports industry estimates that “using pig ramps and jumper lines can reduce emissions from pigging by up to 85 percent at a cost of approximately US \$8,175 per facility.”<sup>135</sup> Additionally, the commenter notes that MGP recommends use of a vapor recovery unit to capture the gas vented when a pig is launched/received, and the gas released from storage tanks that receive the liquid

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<sup>130</sup> Id. at 1-15 – 1-16.

<sup>131</sup> Id. at 1-47 – 1-48.

<sup>132</sup> Id. at 1-48.

<sup>133</sup> Methane Guiding Principles, About, <https://methaneguidingprinciples.org/about/> (last visited Jan. 25, 2022).

<sup>134</sup> Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Engineering Design and Construction at 11 (Nov. 2019), <https://methaneguidingprinciples.org/wp-content/uploads/2019/11/ReducingMethane-Emissions-Engineering-Design-Guide.pdf>.

<sup>135</sup> Id. at 12.

and debris removed by the pig.<sup>136</sup> As a last resort, captured gas can be flared rather than vented, although we emphasize again that flaring should only be used when other alternatives to venting are not feasible or would jeopardize safety.<sup>137</sup>

The commenter (0844-EDF *et al.*) reports that regarding blowdowns, the MGP recommends an initial practice of avoiding blowdowns whenever possible. Inline-inspection tools and smart pigs (with the other mitigation measures discussed to reduce pigging emissions) that can be deployed without having to blowdown a pipeline segment are preferable, and necessary blowdowns should be planned in advance and bundled to decrease overall emissions.<sup>138</sup> When blowdowns must occur, the MGP details additional mitigation strategies to reduce blowdown emissions, which are aligned with EPA's November 2021 Proposal:

- Lower the pressure in the pipeline by allowing consumer drawdown;
- Re-route the gas to an existing network with lower pressure or use it as fuel;
- Recompression;
- Mobile compressor stations;
- Install plugging equipment to shorten the segment of pipeline involved; use isolation valves to minimize impact;
- Make new connections and repair with a hot tap;
- Use in-line inspection (ILI), or 'smart pig' technologies instead of hydrotests;
- Reroute the natural gas to a duct burner, thermal oxidizer, or flare if possible, planned, and allowed (although flaring is not always possible during an emergency, and should only be used when other options are infeasible or unsafe).<sup>139</sup>

*Colorado Pigging and Blowdown Standards.* The commenter (0844-EDF *et al.*) states that the Colorado Air Quality Control Commission recently adopted standards to limit oil and gas methane and air pollution, including establishing requirements to reduce pipeline pigging and blowdown emissions.<sup>140</sup> The Commission requires that pipeline "owners or operators capture and recover gas from pigging and blowdown activities, and if not possible, to request Division approval to install and operate air pollution control equipment, such as vapor recovery, flare/combustors, or a Division-approved alternative to achieve a 95 percent reduction in hydrocarbon emissions."<sup>141</sup>

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<sup>136</sup> Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 9 (Nov. 2019), <https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-EmissionsOperational-Repairs-Guide.pdf>.

<sup>137</sup> *Id.*

<sup>138</sup> *Id.* at 12.

<sup>139</sup> Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Transmission, Storage, LNG Terminals and Distribution at 9 (Sept. 2020), <https://methaneguidingprinciples.org/wp-content/uploads/2020/09/Reducing-Methane-Emissions-transmission-storage-LNG-terminals-and-distribution-Guide.pdf>; see also Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 12 (Nov. 2019) (referring to the use of hot taps and flaring).

<sup>140</sup> Colorado Air Quality Control Commission, Regulation No. 7, 5 CCR 1001-9 Section II.H at p164-171, available at [https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn\\_Z0x50X/view](https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view).

<sup>141</sup> *Id.* at p396, Part X., Statement of Basis, Specific Statutory Authority, and Purpose for December 17, 2021 Revisions.

The commenter (0844-EDF *et al.*) provides that the standard requires that pipeline owners or operators use “best practices to minimize emissions from pigging operations and blowdowns during normal operations.”<sup>142</sup> The identified best practices include (a) keeping pipeline access openings on the pig receiver closed at all times except when a pig is being placed into or removed from the receiver, or during active pipeline maintenance activities; (b) using liquids management system to reduce the accumulation of liquids in the pigging unit; (c) rerouting gas to a low-pressure system using existing piping connections, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems. The commenter adds that standards also require that operators create or update an operating and maintenance plan to provide for the use of these additional best practices:

1. Using short pig barrels, where it reduces the gas volume for potential release.
2. Planning for venting-reduction steps, such as pipeline pump down techniques (*e.g.*, in-line compressors, portable compressors, ejector), when large vessels and pipelines need to be isolated and depressurized.
3. Minimizing the volume that must be released. For example, adding stops to isolate a smaller section of a pipeline to reduce the length of pipe that must be vented.
4. Using inert gases and pigs to perform pipeline purges.
5. Hot tapping to make new connections to pipelines.
6. Coordinating operational repairs and routine maintenance to minimize the number of emissions events and volume.<sup>143</sup>

The commenter (0844-EDF *et al.*) asserts that there are numerous cost-effective technologies and work practices that can significantly reduce methane emissions from pipeline blowdowns. The commenter notes that the examples provided above do not represent all available options or all operators using these practices.

#### ***18.2.4 Opposition to Regulation of Emissions from Pigging Operations Without Further Consideration***

Several commenters (0599-MSD, 0742-ADEC, 0755-TPA, 0782-Berkshire Hathaway Energy Company (BHE), 0815-American Gas Association (AGA), 0817-GPA, 0923-Lambda Energy Resources LLC (Lambda)) express opposition to regulating emissions from pigging operations and/or oppose without further consideration.

Commenter (0782-BHE) discourages EPA from adding vented emissions from pigging to the regulations, especially for the transmission and storage (T&S) segment. Related discussion in the November 2021 Proposal focuses on pigging operations upstream of T&S (and gas processing), where pigging may be conducted more frequently to manage liquids that can gather in lines. Liquids are removed upstream of T&S, and pigging is conducted in the T&S segment on a less frequent basis and for a different purpose – to manage pipeline integrity issues. Where possible, the commenter states that they employ best operating and maintenance practices to reduce pigging emissions; however, there are instances where public, employee, and contractor safety

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<sup>142</sup> Id. at 5 CCR 1001-9 Section II.H.4 at p169.

<sup>143</sup> Id. at 5 CCR 1001-9 Section II.H.4.d. at p170.

and asset management are of the highest priority and importance and some venting may occur. At this time, there is limited information available on emissions from pigging operations for T&S, but operator experience indicates this is a relatively small emissions source for the T&S sector. Because a PHMSA program is in place and emissions characteristics are not well understood, the commenter recommends against EPA adding T&S pigging operations into the regulations. At most, the commenter suggests that EPA further investigate the characteristic emissions for T&S (*i.e.*, typical event emissions, frequency of events) before considering any additional action.

Commenters (0599-MS, 0817-GPA) state that “pipelines” should not be regulated as “affected facilities” for purposes of regulating pipeline blowdowns. The commenter notes that it is unclear whether EPA intends to propose language regulating pipeline blowdowns or the pipelines themselves. As a threshold matter, blowdowns associated with pigging operations must be considered separate and apart from blowdown associated with other pipeline operations. The commenters note that blowdowns associated with pigging operations occur at discrete pig launchers and pig receivers, are typically small, and are generally predictable. Pipeline blowdowns, on the other hand, can occur anywhere along the pipeline, can be large, and occur due to unpredictable maintenance or emergency needs.

The commenters (0599-MS, 0817-GPA) assert that before developing any proposal concerning pipelines as “affected facilities,” EPA must identify and explain for stakeholders the “stationary source” within which this “affected facility” would be found. Indeed, the commenter notes that no NSPS standard currently applies to pipelines as stationary sources and EPA has not historically defined pipelines as stationary sources and it is difficult, then, to understand EPA’s position that pipelines could be designated as “affected facilities.”<sup>144</sup> (See section 18.2.5 below for further comments on their position on designating pipelines as affected facilities.) Moreover, pipelines are highly regulated already. Hence, designating entire pipelines as either a stationary source or an affected facility would require coordination with the Federal Energy Regulatory Commission, the Pipeline and Hazardous Safety Administration, and state agencies and require extensive case-by-case evaluation of pipelines and related “affected facilities” that span miles, cross property lines and state borders, and may have multiple operators. Moreover, the commenters state that “pipelines” can be difficult to define. There are hundreds of thousands of pipeline segments and tracking NSPS applicability for individual segments would be burdensome and complicated. According to the commenters, the time, effort, and cost of this alone would be significant. Pipeline blowdowns can cover any combination of segments depending on the locations of isolation valves. Some of these segments would be classified as “existing” while others would be “new, modified, or reconstructed.” The commenters believe that this would likely lead to confusion as to which standard applies to multi-segment blowdowns and unnecessarily subjects operators to non-compliance concerns.

Regardless of how EPA attempts to define or designate pipelines, the commenters (0599-MS, 0817-GPA) assert that EPA should not regulate pipeline blowdowns under the NSPS. Blowdown is defined elsewhere within the CAA as the “act of emptying or depressurizing a vessel.” 40

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<sup>144</sup> See *ASARCO, Inc. v. EPA*, 578 F.2d 319, 327 (D.C. Cir. 1978) (rejecting EPA’s arguments favoring the “bubble concept” and holding that the Act’s definition of “stationary source” precluded the EPA from changing the unit to which the NSPS at issue applied to a combination of units).



C.F.R. § 98.6 (emphasis added). This is not a consistent *source* of emissions, and this act often occurs in the field and in remote areas. Not all blowdown activities are planned as they are safety-driven and random in nature and, therefore, difficult to define in the context of an “affected facility” for purposes of NSPS. Although operators can, and do, reduce blowdown volume for planned, non-emergency blowdowns, there is very little ability to do this for emergency blowdowns. Further, emergency blowdowns are necessary, critical emergency operational practices required to keep pipelines operating safely. The commenters suggest that EPA can only consider regulating *planned* blowdown events, but that any regulation of planned events still does not fit within the NSPS scheme.

Commenter (0755-TPA) questions the appropriateness of imposing regulations regarding pipeline blowdowns under the NSPS or any existing source standards. To begin with, the commenter notes that pipeline blowdowns should not be regulated as a source category; a blowdown is not traditionally considered to be an identifiable source of emissions, but rather an action taken for safety and/or operational reasons in the field.<sup>145</sup> Moreover, source categories in the NSPS context have traditionally been limited to structures that serve as emission sources. See, e.g., 40 CFR § 60.2 (defining stationary source to mean “any building, structure, facility, or installation which emits or may emit any air pollutant.”). Pipelines, which are generally located underground and do not have normal operating emissions, do not fit that description, which may explain why they heretofore been subject to NSPS regulation as a separate source category.

In addition, the commenter (0755-TPA) asserts that regulations in this area would present unduly complex compliance issues. A pipeline blowdown can affect numerous different pipeline segments, some that might be considered new or modified under the rules, and some that might be considered existing. This would raise compliance questions of whether the pipeline affected by the blowdown activity was governed by standards applicable to new sources, existing sources, or both. The commenter states that this could be an extremely difficult question to answer in practice, given that pipelines can run for hundreds or thousands of miles and can be modified or replaced in numerous shorter segments within the overall pipeline length. In addition, they note that there are many types of pipelines outside of the oil and natural gas sector, and regulating pipeline emissions, which is essentially what this emission category would be, would require a broader look at emissions from pipelines prior to proposing a rule.

Commenter (0755-TPA) notes that, in contrast to planned non-emergency blowdowns, where operators are able to reduce blowdown volumes, exigent circumstances such as unplanned repairs or emergencies create a situation where operators have very limited ability to plan ahead and reduce blowdown volumes or emissions. The commenter asserts that it would be inappropriate to impose emissions limits in these circumstances, because it would present a safety issue if operators had to delay blowdowns in order to meet emissions limits, e.g., by delaying the blowdown until a portable control device was in place. EPA's rules should not have the effect of causing operators to delay critical emergency operational practices, which can be essential to keep pipelines operating safely and to meet regulatory emissions limits.

Commenter (0815-AGA) supports efforts to reduce emissions from blowdowns but asserts that EPA needs to offer a new opportunity for affected small entity representatives (SERs) to

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<sup>145</sup> See, e.g., 40 CFR § 98.6 (a blowdown is “the act of emptying or depressuring”).

comment on how proposed standards would impact their costs and operations. The commenter states that this past summer, EPA did not allow an AGA member company that operates a small entity interstate natural gas transmission pipeline to provide testimony before EPA's SBAR panel on the grounds that EPA's proposed methane standards would only affect pipeline compression, not the pipeline itself, and the SER operated an interstate pipeline that had no compression. The commenter notes that it is difficult to determine at this stage how a proposed pipeline blowdown standard would affect such small interstate pipelines without a description of the possible regulatory options under consideration. The commenter states that if the agency wishes to proceed with a pipeline blowdown standard, it will need to convene the SBAR and allow affected interstate pipeline SERs to inform the agency on how the proposed standards would affect small interstate pipelines.

The commenter (0815-AGA) notes that their members have voluntarily sought to improve estimates of blowdown emissions and to reduce emissions from blowdowns on both distribution and transmission pipelines. The commenter adds that member subject matter experts developed the AGA's Blowdown Emission Reduction White Paper,<sup>146</sup> published in August 2020, to share lessons learned and leading practices for avoiding the need for blowdowns when possible and for reducing emissions when blowdowns are necessary. According to the commenter, there is still much to learn, and they plan to review and update the White Paper to help members achieve their emission reduction goals.

Commenter (0755-TPA) recommends that, at a minimum, any rulemaking in this area be preceded by an ICR aimed at gathering data that could allow EPA to fully assess the level of emissions at issue as well as the costs of imposing regulations in this area. The commenter asserts that EPA should not impose requirements on pigging activities at this time as there is currently insufficient data to adequately inform rulemaking. The commenters believe that EPA lacks sufficient information regarding the number of sources, emissions resulting from pigging, and similar basic information that traditionally would be input into a regulatory cost-benefit analysis and necessary to make a determination of BSER. The commenter notes that while EPA collects some data related to pig launchers and receivers through the greenhouse gas reporting program (GHGRP), this information is limited to relatively large operations (above 50 cubic feet actual volume) and the emissions data that is captured reflects aggregate emissions data from multiple sources across an entire basin in the context of gathering and boosting. The commenter asserts that such macro-level, imprecise, and limited data cannot reliably inform a useful cost-benefit analysis.

Commenters (0599-MS, 0817-GPA) contend that EPA must determine it has sufficient information to support the November 2021 Proposal, including support for any proposed regulation being cost-effective. The commenters recommend that EPA, at a minimum, first engage in data gathering to understand the issues presented. The commenters urge EPA not to develop any potential new source performance standards and existing source rules to address pipeline pigging—and blowdowns associated directly with pigging—because there is insufficient

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<sup>146</sup> The AGA Blowdown Emission Reduction White Paper:  
<https://www.aga.org/contentassets/fdb295e9799449d78d3b07b4a0eac453/aga-blowdown-emissions-reductionwhite-paper-final-8.5.20.pdf>.

data regarding the inventory of pigging infrastructure, insufficient data regarding emission reductions associated with any proposed regulations, and broad regulation would fail to include the variety of pigging operations where benefits of emission reduction are unknown. Moreover, the commenters state that the November 2021 Proposal as it relates to other affected facilities will result in dramatic investments of time and resources that will be a challenge for the agency to finalize and then for the midstream sector to absorb.

Commenters (0599-MS, 0817-GPA) note that before regulating pigging operations, EPA should first conduct a thorough cost-benefit analysis to understand the emissions threshold at which additional regulation or control measures are cost-effective. The commenters recommend that EPA exempt from regulation pig launchers and pig receivers below such appropriate emission threshold as some pig launchers and receivers have zero or very low emissions, making the costs and benefits of regulating all equipment inappropriate. The commenters contend that reducing blowdown emissions through recovery or combustion control equipment requires significant capital and maintenance expenses, new operating procedures, and personnel time. Moreover, the commenters recommend that EPA only consider proposed language regarding the control of pigging emissions for new facility construction due to the significant capital required to add, or modify or retrofit existing control devices. The commenters suggest that EPA consider proxies for emissions, such as pipeline size, pressure, and/or blowdown frequency but any proxies should roughly equate to a reasonable emissions threshold where costs and benefits are appropriate.

The commenters (0599-MS, 0817-GPA) express that they are not aware of a nationwide inventory of pig launchers and pig receivers—or any other methodology to estimate such inventory. Nor are the commenters aware of sufficient data or methodologies to estimate the total emissions currently resulting from pigging operations. Indeed, according to the commenters, there are pig launchers and pig receivers that do not have appreciable emissions at all. As detailed further throughout their comments, they note that pigging operations are vastly diverse and without any meaningful data, broad regulation of these operations would fail. Because this is not a “one-size-fits-all” type of operation, and because the varying operations are often highly technical and individualized, the commenters contend it would be premature to advance any EPA regulation here.

Further, as evidenced by the language used in EPA’s requests for comment, the commenters (0599-MS, 0817-GPA) assert that the agency has little to no information regarding pigging operations beyond data associated with the currently-regulated reporting of certain blowdown events through the GHGRP. While blowdown data for pig launchers and pig receivers is collected through the GHGRP, this data set is limited. It only collects data for those pig launchers and pig receivers larger than 50 cubic feet actual volume and most launchers/receivers are smaller than this. Further, the emissions are reported as an aggregate within the reporting facility (*i.e.*, the entire basin for gathering and boosting), and thus do not provide information that would be useful for establishing performance standards for a specific affected facility. Moreover, potential emissions are going to vary widely depending on multiple factors, including frequency of activity, as well as the size, gas pressure, gas composition, temperature, and elevation changes in the pipeline.

At best, the commenters (0599-MS, 0817-GPA) suggest that EPA open a separate public docket to collect more information to help the agency determine whether, and if so how, pigging operations should be subject to federal regulations. The commenters recommend that EPA focus on seeking data identifying those pigging operations with potentially high enough emissions to justify federal rules—such as those with frequent blowdowns (*e.g.*, weekly or more), those operating at high pressure (*e.g.*, 500 pounds per square inch (psi) or greater), and those used on larger diameter pipelines (12 inches or greater).

Commenters (0599-MS, 0817-GPA) also urge EPA to engage further with stakeholders to understand fully the specifics of pigging operations before proceeding to develop a proposed rule to cover those operations. According to the commenters, absent further engagement with those most knowledgeable about these operations, they are generally concerned that any proposed language would apply an incorrect understanding of pigging and blowdown operations.

The commenters (0599-MS, 0817-GPA) assert that EPA does not appear to distinguish between pig launcher and pig receiver blowdown emissions (and potential reduction/control options) and pig receiver liquids (and potential liquids management options). The commenters explain that these are distinct issues that would need to be studied and understood fully before regulations are proposed. Pigs are pushed through the pipeline segment by natural gas via differential pressure (*i.e.*, the pressure behind the pig is higher than the pressure in front). The commenters note for clarity that most liquids pushed by the pig either continue down the pipeline (if the pig receiver is not at a compressor station or gas plant) or are collected in a vessel such as a slug catcher (if the pig receiver is at a compressor station or gas plant). In other words, most of the liquids that are pushed by the pig are not retained in the pig receiver. The vast majority of liquids either continue through the pipeline and/or are collected downstream in a vessel (such as a slug catcher). There are no liquids behind the pig. The commenters note this because when the pig enters the receiver barrel (which generally has a larger diameter than the pig), the differential pressure is “released,” and this flush of gas also pushes liquids out of the receiver. Generally, operators allow gas to sweep through the receiver before isolating the receiver, blowing it down, opening the door, and removing the pig (or pigs). Any residual liquids retained in the pig receiver typically range from a few cups to a few gallons. This liquid is a mix of condensate, water, used oils, and other non-hydrocarbon impurities. Upon opening the pig receiver door, these residual liquids are captured in a trough, sump, or bucket.

The commenters (0599-MS, 0817-GPA) assert that EPA similarly does not appear to recognize that although pig launcher and pig receiver blowdowns are planned and/or predictable, other emission events such as pipeline blowdown are not always planned.<sup>147</sup> The commenters suggest that any future regulation, if supported by data, must ensure terminology is appropriately defined and encapsulates a clear understanding of pigging operations (and distinctions between

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<sup>147</sup> American Gas Association, Blowdown Emission Reduction White Paper, 5, 7 (available at <https://www.aga.org/contentassets/fdb295e9799449d78d3b07b4a0eac453/aga-blowdown-emissions-reductionwhite-paper-final-8.5.20.pdf>) (last accessed January 12, 2022) (Providing additional information regarding the various types of planned and unplanned blowdowns).

blowdown emissions and liquids management) and other pipeline blowdowns, which are generally unpredictable events.

Commenter (0923-Lambda) urges EPA to avoid new regulations to pipeline pigging operations. Pigging pipelines are a very necessary and frequent practice within the commenter's operations. Most pigging operations consist of minute amounts of hydrocarbons (est. 1-20 scf per event) being blown down from either a pig launcher or pig receiver. Because of the minimal amount of venting (est. 10 mcf [thousand cubic feet] per year for all events) associated with these operations, the commenter finds extra efforts to capture gas associated with this practice to be overly burdensome and in some cases infeasible and wasteful. In the event a line is evacuated of its product, the commenter would flare the gas (and report it in subpart W as combustion) or otherwise capture the product to sell.

Commenter (0742-ADEC) asserts that pipeline pigging has no place within the November 2021 Proposal as most states already have in place pipeline agencies that are best suited to strictly regulate pipeline operations. The commenter notes that no oil and gas production facility in Alaska owns a pipeline for which such requirements would be applicable. The pipelines are all owned and operated by separate entities and would comprise separate stationary sources. The commenter further states that no pigging operation alone triggers a permit in Alaska regulations based solely on emissions, and nowhere in the November 2021 Proposal does EPA suggest a Title V permit would be required simply due to source category for “pipeline pigging operations.” The commenter reports that Alaska regulates pipeline pigging operations as insignificant sources of emissions for Title V purposes.<sup>148</sup>

### ***18.2.5 Affected Facility***

Commenter (0844-EDF *et al.*) asserts that pipelines could be defined as an affected facility, defined by pipeline segments based on ownership and major geographic boundaries. The commenter notes that there are benefits to defining the pipeline as the affected facility. First, bundling multiple activities into a single blowdown event is a helpful practice to reduce the total number of required blowdowns on a pipeline and thus to reduce the overall methane emissions.<sup>149</sup> To facilitate planning in advance and ensuring maximum bundling to minimize emissions, the commenter suggests that it would be helpful to consider all different types of blowdowns (including pigging) and view the pipeline as a whole—or even a pipeline segment—as the affected facility.

Furthermore, the commenter (0844-EDF *et al.*) contends that it is beneficial to treat the pipeline itself as an affected facility because a blowdown is not necessarily limited to a discrete point on the pipeline. The amount of methane released during a blowdown is related to the length of the

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<sup>148</sup> 18 AAC 50.326(f)(97).

<sup>149</sup> See Methane Guiding Principles, Reducing Methane Emissions: Best Practice Guide, Operational Repairs at 5 (Nov. 2019), <https://methaneguidingprinciples.org/wp-content/uploads/2019/11/Reducing-Methane-EmissionsOperational-Repairs-Guide.pdf>

(“Look for opportunities to co-ordinate operational repairs and routine maintenance and repairs to minimize the number of blowdowns.”); California Public Utilities Commission, Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371, Decision 17-06-015, Appendix B: Best Practices for Natural Gas Leak Abatement Program (June 15, 2017).

section of pipeline that must be blown down, which depends on where the pipeline has valves that can be closed. Thus, blowing down a longer length of pipeline will result in greater methane emissions:

The commenter (0844-EDF *et al.*) reports that, in order to blowdown a section of pipe, that section must be isolated from upstream and downstream pipe sections by closing valves. Valve spacing varies across the system but is generally ten to twenty miles between valves. This means that, without installing a new temporary valve[,], the minimum distance that can be blown down in order to allow for establishment of maximum allowable operating pressure (MAOP) using pressure testing is 10 – 20 miles (*i.e.*, the valve spacing on that segment of pipeline). As such, if only a two-mile section of pipe between valves needed to be pressure tested (for example because it was pre-1970 pipe in an HCA<sup>150</sup>) but the rest of the section between the valves did not need to be tested (because it was not in an HCA), then the total miles that would need to be blown down to accommodate the pressure testing could be five to ten times longer than the actual pressure test mileage.<sup>151</sup>

For ease of oversight and establishing the BSER, the commenter (0844-EDF *et al.*) recommends that EPA consider defining pipelines as the affected facility, with the endpoints of each pipeline facility established in segments where appropriate. Pipeline segments could be defined by pipeline ownership and major geographic boundaries.

Commenter (0424-WVDEP) asserts that EPA's consideration of whether the pipeline itself could be defined as an affected facility for the purposes of regulating blowdowns is flawed because pipelines do not meet the definition of a stationary source, as defined in section 111(a) of the CAA. The term "stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant. This definition requires boundaries to define the stationary source. Intrastate or interstate pipelines do not have an established boundary and therefore do not meet the definition. According to the Gas Pipeline Safety Division of the West Virginia Public Service Commission, there are approximately 14,000 miles of intrastate natural gas and hazardous liquid transmission and regulated gathering pipelines and natural gas distribution pipelines within the state. The commenter (0424-WVDEP) states that the characterization of the pipeline system in terms of miles rather than number of facilities is an illustration that pipelines do not meet the definition of a stationary source and should not be regulated as such. The commenter notes that in West Virginia, if a pigging operation and related blowdown activity meets the stationary source threshold the related air emissions are currently regulated as part of the stationary source, typically by limiting the number of events over a specified timeframe.

Commenters (0599-MS, 0817-GPA) note that EPA's request for comment implies it is considering the regulation of previously constructed pipelines-to which pigging infrastructure may be temporarily or permanently installed-as a stationary source. The commenters note that

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<sup>150</sup> An HCA is a buffer around a section of a pipeline where there are higher concentrations of people, like in an urban community.

<sup>151</sup> M.J. Bradley & Associates, Pipeline Blowdown Emissions and Mitigation Options at 14 (June 2016), <http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf>.

the current record lacks support or reason for regulating “pigging operations” as an “affected facility”.

Although the commenters (0599-MS, 0817-GPA) believe that considering whether pigging operations should be “affected facilities” is, at best, premature, the following comments are offered. Subpart A of the Act’s regulatory framework provides the procedural application of the NSPS as established in other subparts and is applicable to “the owner or operator of any *stationary source* which contains an *affected facility*, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.” 40 C.F.R. § 60.1(a)–(b) (emphasis added). Each promulgated NSPS should explicitly define and describe the “affected facilities” to which it applies, but NSPS first must apply to a stationary source containing the affected facility. Both the statute and general NSPS regulations define “stationary source” as “any building, structure, or installation which emits or may emit any air pollutant.” 42 U.S.C. § 7411(a)(3); 40 C.F.R. § 60.2. And “affected facility,” with reference to a stationary source, means “any apparatus to which a standard is applicable.” 40 C.F.R. § 60.2 (further defining the terms “commenced” to mean “with respect to the definition of new source in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification” and “construction” to mean “fabrication, erection, or installation of an affected facility.”).

#### ***18.2.6 Pipeline and Hazardous Materials Safety Administration (PHMSA) Coordination***

Commenter (0844-EDF *et al.*), as with other comments mentioned previously, recommend that EPA continue to coordinate with PHMSA at U.S. Department of Transportation (DOT), to ensure comprehensive oversight of pipeline methane emissions across agencies. The commenter notes that The PIPES Act of 2020 directed PHMSA to finalize new standards to extend its oversight of gathering lines.<sup>152</sup> In November 2021, PHMSA issued a final rule extending basic annual reporting requirements to all onshore gas gathering lines and extending leak survey and repair requirements to an additional 20,336 miles of gathering lines.<sup>153</sup> The rule represents an important step forward to increase transparency and heighten oversight of gathering pipelines. However, the commenter notes that it does not establish requirements to limit methane emissions from pigging and blowdown activities. The commenter recommends that EPA remedy this oversight and propose emission limitations for pigging and blowdowns on gathering lines in its forthcoming supplemental rulemaking.

Commenter (0755-TPA) recommends that any regulations in this area should only be implemented after coordination and consultation with PHMSA both to avoid regulatory overlap, duplication, and inconsistency, and in particular to ensure that PHMSA’s pipeline safety program is not jeopardized by rules that might incentivize operators to delay emergency blowdowns to remain in compliance with EPA emissions limits. Further consideration of these issues by EPA and PHMSA might lead to the conclusion that any regulation of blowdown

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<sup>152</sup> FY2021 Omnibus and COVID Relief Response Act, HR133, Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) at § 112(a) (Dec. 27, 2020).

<sup>153</sup> PHMSA, Final Rule: Pipeline Safety: Safety of Gas Gathering Pipelines, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

emissions should be accomplished through a program other than the traditional EPA NSPS rules or EGs for existing sources.

Similarly, commenter (0585-KOGA) notes that PHMSA is already working on similar requirements and recommends that EPA not duplicate emission requirements and additional reporting requirements for pipeline operators. The commenter asserts that there would be no environmental benefit and would only increase administrative costs to manage two separate regulations and reporting to two separate agencies for similar regulatory requirements.

The commenter (0585-KOGA) provides details on the PIPES Act and PHMSA work. The PIPES Act of 2020 (Pub. L. 116-260, Division R) was signed into law on December 27, 2020. This law contains several provisions that specifically address the elimination of hazardous leaks and minimization of releases of natural gas from pipeline facilities. Section 114(b) of the PIPES Act of 2020 contains self-executing provisions that apply directly to pipeline operators. This section requires each pipeline operator to update its inspection and maintenance plan required under 49 U.S.C. 60108(a) no later than one year after the date of enactment of the PIPES Act of 2020 (*i.e.*, by December 27, 2021) to address the elimination of hazardous leaks and minimization of releases of natural gas (including, and not limited to, intentional venting during normal operations and maintenance) from the operators' pipeline facilities (49 U.S.C. 60108(a)(2)(D)).

The commenter (0585-KOGA) adds that the PIPES Act of 2020 also requires those plans to address the replacement or remediation of pipelines that are known to leak due to their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history (49 U.S.C. 60108(a)(2)(E)). In addition, 49 U.S.C. 60108(a)(2) requires that operators continue updating these plans to meet the requirements of any future regulations related to leak detection and repair that are promulgated under 49 U.S.C. 60102(q). Pursuant to the PIPES Act of 2020, operators must have completed updates to their plans by December 27, 2021. PHMSA and state partners are required to inspect these plans in 2022.

On June 10, 2021, the commenter (0585-KOGA) notes that the PHMSA published an advisory bulletin in the Federal Register titled "Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities" (86 FR 31002) reminding pipeline operators of their obligation to comply with Section 114 of the PIPES Act of 2020 by December 27, 2021. That advisory bulletin reminded owners and operators of pipeline facilities that the PIPES Act of 2020 requires operators to update their inspection and maintenance plans to identify procedures to prevent and mitigate both vented/intentional and fugitive/unintentional pipeline emissions. Vented emissions can occur during repairs, maintenance, or operations of pressure relief systems, or other controlled activities. Fugitive emissions include leaks from mains or service lines, meters, or excavation damage, as well as other accidental releases.

Commenter (0831-AXPC) notes that PHMSA is already regulating the midstream pipeline system and recently passed the PHMSA reauthorization law that directed PHMSA to reduce methane emissions in the pipeline. To the extent that EPA believes that it is may be necessary to regulate pipeline pigging operations, the commenter recommends that EPA allow PHMSA to



first develop regulations and determine whether it would be appropriate for EPA to regulate on top of PHMSA.

Commenter (0782-BHE) recommends that EPA exclude T&S pigging operations from the regulations because there is a PHMSA program in place and emissions characteristics are not well understood. At most, the commenter suggests that EPA further investigate the characteristic emissions for T&S (*i.e.*, typical event emissions, frequency of events) before considering any additional action. The commenter notes that transmission pipeline operations, including pigging for pipeline integrity purposes, are regulated by PHMSA. In 2021, operators were required to review and update operating and maintenance (O&M) procedures and minimize vented and leak emissions. The commenter adds that PHMSA is implementing a program in 2022 to assess the status of O&M procedures and recommends allowing the assessment of the updated PHMSA program and requirements to occur before considering additional requirements from EPA. Depending on the significance of the pipeline defect, compromise, or anomaly discovered from pigging, PHMSA may require an immediate action to inspect and repair the fault or defect. When immediate action is required, there may be insufficient time to significantly reduce pipeline pressures and blowdown volumes that may be emitted from a pigging operation – which would most typically be relatively small for any particular event.

As EPA notes in the November 2021 Proposal, the commenter (0782-BHE) states that pigging operations are vital to maintaining the integrity of the pipeline. Pigging provides information to operators about the structural characteristics of the pipeline for safety and maintenance purposes. At this time, the commenter states there is limited information available on emissions from pigging operations for T&S, but operator experience indicates this is a relatively small emissions source for the T&S sector.

Commenter (1391-INGAA) reports that pigging operations are essential for pipeline safety, and its members are working to minimize emissions from these operations. The commenter asserts that EPA needs to be aware of PHMSA efforts and coordinate with the agency to avoid duplicative or conflicting regulations. The commenter contends that EPA should consider deferring to PHMSA on the issue of pigging emissions and supplement only if PHMSA's regulation prove to be lacking. The commenter provides details on pigging and blowdown activities for consideration.

The commenter (1391-INGAA) notes that PHMSA has numerous safety regulations with which their members must comply. In recent years, PHMSA has also been examining options to reduce methane emissions associated with pigging operations. For example, it issued a proposed rule in 2016 that would have regulated blowdown emissions from pipelines.<sup>154</sup> Although the proposed rule has not been finalized, the commenter reports that PHMSA has made it clear in response to

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<sup>154</sup> 81 Fed. Reg. 20,722, 20,741 (Apr. 8, 2016) (noting “proposed rule is expected to prevent incidents, leaks, and other types of failure that might occur, thereby preventing future releases of greenhouse gases ... to the atmosphere, thus avoiding additional contributions to global climate change” and estimating “net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane”).

President Biden’s executive orders on climate change that it will be examining methane emissions from pipelines.<sup>155</sup>

The commenter (1391-INGAA) states that it is important that EPA understand two key points. First, the purpose of pigging differs in each segment of the oil and gas industry, and that these differences impact the potential for emissions. Second, emissions from pigging operations depend on a variety of factors, including the frequency of pigging. The commenter elaborates on these two points.

The commenter (1391-INGAA) provides that, with regard to the *first point*, pigging is different in the transmission segment as compared to the gathering and boosting segment. The general function of a pig is either to clear a pipeline of liquids and debris to avoid reduced gas flow or to monitor the condition of the pipeline for safety purposes. It is the latter reason that pigging typically occurs in the transmission and storage segment.

With regard to the *second point*, the commenter (1391-INGAA) states that pigging happens far less frequently in the transmission segment. The transmission segment involves the movement of pipeline quality gas, which means that the gas has already been cleaned of most impurities at the gas plant and contains far fewer liquids. Thus, pigging to clear the transmission pipeline of liquids and debris occurs far less frequently than it does in the gathering and boosting segments. For example, in the gathering and boosting segments, gathering lines in some areas might be pigged on a weekly or even a daily basis. In contrast, one member of theirs reports that it sometimes mechanically pigs its pipelines annually—and at least every three years—for maintenance purposes. That member also typically conducts an in-line “smart pig” inspection of the pipeline for safety purposes once every five to seven years.<sup>156</sup> In addition, the commenter states that emissions from pigging operations involve emissions only from blowdowns of the pigging barrels—not the entire segment of the pipeline.

The commenter (1391-INGAA) states that these key points result in methane and VOC emissions from pigging operations in the transmission segment being extremely low. The commenter asserts that EPA cannot assume that all pigging operations are similarly situated, and the Agency must undertake segment-specific analysis as it continues to evaluate options for these sources.

Commenter (1391-INGAA) explains that pigging provides information to operators about the structural characteristics of the pipeline for safety and maintenance purposes. The commenter recognizes the need to reduce emissions from pigging operations while conducting integrity and maintenance-related work, where practical. These emissions can be reduced in many instances, but the safety of the public, employees, contractors, and assets must remain priorities. Before considering any additional action, the commenter recommends that EPA further investigate the characteristics of emissions for pigging in the transmission and storage segment. The commenter

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<sup>155</sup> 75 See, e.g., 86 Fed. Reg. 31,002 (June 10, 2021) (PHMSA Advisory Bulletin requiring pipeline operators “to address eliminating hazardous leaks and minimizing releases of natural gas ... from their pipeline facilities”).

<sup>156</sup> PHMSA regulations require that all transmission pipelines within High Consequence Areas (*i.e.*, those areas with sufficient population close to the pipeline) are required to be assessed for integrity at least once every seven years. 49 C.F.R. § 192.937(a). These assessments are usually accomplished by an in-line pigging inspection.

reports that they are working to produce a white paper of best practices that will identify various strategies to reduce emissions from the interstate natural gas pipeline network.

With regard to blowdown emissions from pipelines, the commenter (1391-INGAA) notes that their members have three sets of options that they take to minimize emissions from these activities. First, members eliminate the need for a blowdown for anomaly repair work or project tie-ins, when possible, by using other repair options such as composite wraps or full encirclement “split” sleeves, and using hot taps for the project work. Using these repair procedures and in-service welding methods can eliminate the need for a blowdown. Second, when a blowdown is required for anomaly repair work or project tie ins, the commenters’ member companies typically reduce the emissions by using customer and company compression to lower the pressure prior to the blowdown. Third, members generally use company-owned or third-party portable compression and/or flares to further lower the pressure and reduce emissions prior to the blowdown. These options may eliminate methane emissions and will, at a minimum, reduce them by 75 percent.

The commenter (1391-INGAA) reports, however, that there are factors that can influence what options can be implemented. For example, in some situations, there is limited time because of the need to quickly address potential integrity concerns. Depending on the significance of the pipeline integrity anomaly, the commenter states that PHMSA may require an immediate excavation to inspect and repair the anomaly. When this occurs, there is not sufficient time to significantly reduce blowdown emissions. Whether the pipeline has a single line or parallel lines to compress the natural gas in the same right-of-way also affects the ability to reduce emissions. A parallel line in the right-of-way makes using the second and third options above much more effective and efficient. Finally, the commenter adds that other factors that can affect the ability to minimize blowdown emissions include limited time because of customer commitments (particularly on cold winter or hot summer days), constrained rights-of-way, and population, environmental, and highway considerations.

## **18.3 Tank Truck Loading**

Response I-18-3: In the November 2021 Proposal, EPA solicited comment and data to assist the Agency in evaluating the potential for developing emissions standards for additional emission sources, including tank truck loading. EPA did not propose emissions standards for tank truck loading in the December 2022 Supplemental Proposal; therefore, this final action does not include emissions standards for these emission sources. We may consider regulation through a future action, including in the next 8-year review of the NSPS. The comment summaries are provided below for reference but substantive responses are not provided because no emissions standards have been proposed for this emissions source.

### ***18.3.1 Regulatory Support***

Commenter (0957-WYCLG) states that the solicitation of comments on the potential for establishing standards for tank truck loading operations is not appropriately included within this notice of proposed rulemaking because it fails to provide an adequate description of the issues involved or terms or substance of a proposed rule. The commenter recommends that this request

for additional information on other sources of emission should instead be its own separate rulemaking, starting with an “Advance Notice of Proposed Rulemaking” to obtain the necessary information.

### ***18.3.2 Support for Regulation Under the NSPS/EG***

Several commenters (0391-KBIC, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0766-CO DPHE, 0781-NTAA, 0789-PADEP, 0809-Earthjustice, 0832-NMED, 0833-Ute EPD, 0918-COLGC, 0943-Sault EPD) support EPA considering the inclusion of requirements to reduce emissions from tank truck loading under the NSPS/EG. Some of these commenters (*e.g.*, 0599-MSD, 0817-GPA) only provide support for the use of bottom filling or submerged fill pipe requirements. Specific examples of comments provided are included in the following paragraphs. the use of bottom filling or a submerged fill pipe to reduce emissions.

Commenter (0809-Earthjustice) indicates that data from the 2017 National Emissions Inventory (NEI) showed that total VOC emissions from tank truck loading operations were approximately 72,448 tons per year nationwide.<sup>157</sup> These numbers are substantial and speak to the urgent need for the agency to address uncontrolled emission sources in this cycle of rulemaking.

Commenter (0809-Earthjustice) recommends that EPA not delay its duty to regulate these significant sources of uncontrolled emissions simply because of inadequate data. The commenter notes that, if a targeted ICR is necessary to supply the agency with data it requires, then the agency should undertake this information gathering without delay and well in advance of its rulemaking deadlines.

Commenter (0809-Earthjustice) recommends that EPA set emissions standards in the NSPS rulemaking, and in its reconsideration and CAA section 112(d)(6) review of the 2012 NESHAP rule because tank truck loading has the potential to emit large amounts of VOCs, methane, and HAPs.

The commenter (0809-Earthjustice) reports that it called on EPA to reconsider its decision not to regulate uncontrolled emissions from tank truck loading ten years ago.<sup>158</sup> The commenter renews their demand that EPA use its section 112 authority to set standards for all known sources of uncontrolled emissions in the oil and gas sector as required under the Clean Air Act. See LEAN, 955 F.3d at 1096.

Commenter (0832-NMED) notes that New Mexico proposed emission control requirements for truck loading operations in Part 50 and encourages EPA to adopt similar requirements in the proposed supplemental rule.

Commenter (0776-CDPHE) cites Colorado’s regulations related to truck loading operations:

Colorado adopted requirements to reduce emissions from tank truck loading operations in

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<sup>157</sup> See also DEP MarkWest Memo, *supra*, at 4 (estimating facility’s potential to emit 1.30 tpy VOCs and 0.05 tpy HAPs from truck unloading)

<sup>158</sup> Reconsideration Petition, *supra*, at app. tbl. 1

2019.<sup>159</sup> In addition to the specific practices described below, Colorado also adopted provisions for “storage tank measurement systems,” which limit emissions from tank liquid measurement activities (for both quality and quantity), through the use of automatic tank gauges and sampling technologies and procedures that avoid opening of the thief hatch during these activities.<sup>160</sup>

Colorado’s regulations require owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12- month basis to control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment. Critically, owners or operators must also have signage on-site notifying third parties (*e.g.*, haulers) of these practices and must implement training for employees and third parties that conduct loadout operations. Operators must also periodically observe loadout to confirm that all storage tanks operate without venting. In 2020, Colorado expanded these requirements to owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis.

Commenter (0918-COLGC) urges EPA to follow the lead of oil and gas producing states and propose a supplemental rule that addresses truck loading emissions. The commenter cites Colorado, Pennsylvania, and New Mexico examples to demonstrate that emissions capture or control is feasible and cost effective.

The commenter (0918-COLGC) states that in Colorado, operators must control venting from storage tank hydrocarbon liquids loadouts at well production facilities, Class II disposal well facilities, natural gas compressor stations and natural gas processing plants. Per this rule, operators must control emissions from the loadout of hydrocarbon liquids from controlled tanks to transport vehicles by either using submerged fill or a vapor collection system.<sup>161</sup> The state determined that the weighted average cost per ton VOC of requiring controls on loadout operations at facilities with tank throughput of 5,000 bbl/year would be \$12,998. The commenter notes that this does not account for the additional methane reductions to be realized from the requirement, nor does it recognize the additional reductions from avoiding the opening of the thief hatch during loadout.<sup>162</sup>

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<sup>159</sup> Reg. 7, Part D, Section II.C.5. Colorado uses API gravity 40 to define “condensate”, not the 50 for which EPA solicits comments. Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110, 63,245 (Nov. 15, 2021)

<sup>160</sup> Reg. 7, Part D, Section II.C.4. These practices also promote worker safety, due to avoiding the need for a person to climb up on the tank and open the thief hatch during gauging and sampling.

<sup>161</sup> Colorado Reg 7. Pt. D, § II.C.5.

<sup>162</sup> Colorado Air Quality Control Commission, Regulatory Analysis for Regulation Number 7 Revisions, p. 23 (Dec. 2019), <https://www.edf.org/sites/default/files/content/Attachment%20B%20-%20Regulatory%20Analysis%2C%20Colorado%20Dep%E2%80%99t%20of%20Public%20Health%20and%20the%20Environment%20%28Dec.%205%2C%202019%29.pdf>.

The commenter (0918-COLGC) states that in Pennsylvania, for all truck load-out operations that service a storage vessel with a total methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 8, 2018, the owner or operator must use a vapor balancing system when removing liquids from the storage vessel and ensure that each tanker truck that is used to remove liquids from the storage vessel has passed an annual leak test. Alternatively, VOC emissions must be controlled with 95 percent or greater efficiency.<sup>163</sup>

The commenter (0918-COLGC) notes that New Mexico is also proposing rules for hydrocarbon liquid transfers. The proposed rules require the owner or operator of a hydrocarbon liquid transfer operation to use vapor balance, vapor recovery, or a control device to control VOC emissions by at least 95 percent, when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker railcar for transport. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98 percent.<sup>164</sup>

Commenters (0391-KBIC, 0586-Navajo EPA, 0605-Muscogee (Creek) Nation, 0781-NTAA, 0833-Ute EPD, 0943-Sault EPD) believe that EPA should require, at a minimum, the use of bottom filling or a submerged fill pipe to reduce emissions. Commenter (0586-Navajo EPA) notes that this requirement is what was recently proposed in its Oil and Natural Gas General Permit.

Commenters (0599-MSD, 0817-GPA) would support the use of submerged fill as a practice for truck loading because the work practice is already in place and therefore likely to be more cost-effective than a control efficiency requirement. The commenters note that quite a few states already require, and most third-party trucking companies already use, submerged fill. The commenter states that from an industry perspective, submerged fill is largely standard industry practice. The commenters do not oppose the proposed regulation to make this a requirement for trucks, as trucks designed for submerged fill have an arm extending to the bottom of the tank and where the hose is connected. The commenters contend that because this is part of the truck and not a separate apparatus a truck operator could install at the facility, EPA's inclusion of a proposed cost estimate for *facility operators* appears somewhat misguided. The commenters assert that any proposal should, therefore, focus on imposing requirements on the truck operator, not the operator of the facility.

### ***18.3.3 Opposition to Regulation Under the NSPS/EG***

#### **18.3.3.1 Federal Regulation of Tank Truck Loading is Not Supported**

Commenters (0599-MSD, 0817-GPA) urge EPA to revisit its understanding of tank to truck loading and related operations prior to proposing any regulatory language. As a threshold matter, EPA's request for comment suggesting the use of three "control options" is confusing. The commenters have concerns regarding any proposed regulation based on an incomplete understanding of tank to truck loading and related operations. Vapor balancing, for example, is

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<sup>163</sup> Pennsylvania GP-5 Permit, Section F; Pennsylvania GP-5A Permit, Section F.

<sup>164</sup> Id. at Section 20.2.50.120, <https://www.env.nm.gov/opf/docketed-matters/>.

not a control option separate from closed vent operating. Rather, operators utilize this method in a more comprehensive manner to ensure safe and efficient truck loading and to ensure low risk of oxygen entering a unit during loading. And where facilities have the ability to pipe liquids downstream, tank truck loading is highly unlikely to even occur as it is unnecessary. However, should EPA determine it receives sufficient information to both understand operations and warrant regulations in addition to state requirements, the commenters provide comments for consideration. The commenters assert that if controls are required, operators will need lead time to account for capital budget planning, design and engineering, procurement, construction, training on new procedures, and other logistics related to installing new equipment. The commenters note that this may vary depending on the availability of equipment and contractors (new compliance requirements can lead to a shortage of both equipment and experienced contractors).

Commenter (0742-ADEC) asserts that tank truck loading operations requirements have no place in the current proposal and should be addressed in a separate rulemaking if at all. The commenter suggests that tank truck loading operations could be addressed in an update to NSPS Subpart KKK, 40 CFR 60.630 Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011, or another already established subpart in a transportation sector that more closely aligns with the topic of leaks at non-primary function core facilities.

Commenter (0599-MSC) recommends no control requirements under EG OOOOc because the ability to control existing truck loading under EG OOOOc increases the difficulty of collecting and controlling emissions safely.

#### 18.3.3.2 Truck Loading Emissions Reduction Requirements Should be Left to the States

Commenter (0810-Petroleum Alliance-OK) recommends that EPA not include any tank truck loading requirements at well sites, especially marginal well sites, and instead leave tank truck loading to be addressed within state's permitting program. The commenter states that EPA's three options are costly, require significant training, and have potential safety issues. The first option, vapor balancing using a closed system, would require significant cost to setup the vapor balancing system and significant training for tank truck operators for proper operation and maintenance, and there are potential safety issues with the introduction of oxygen into atmospheric tanks. The second option, the use of a vapor recovery system, would require significant cost especially for marginal/low production wells. The third option considers requiring liquid pipeline connections for all locations. The commenter suggests that this is completely impractical and inordinately expensive. They explain that if a liquid pipeline was accessible and economically feasible, operators would be using pipelines. Finally, the commenter notes that the bulk of the fluids hauled by tank trucks in Oklahoma consist mostly of produced water with minimal emissions.

Commenter (0740-Utah Petroleum Association (UPA)) states that tank truck control requirements would yield marginal benefits, the state has regulations in place, and it would be impractical and impossible to directly pipe liquids downstream. The commenter reports that tank

truck loading only accounts for 1.1 percent of the Utah oil and gas emissions inventory, a very small amount,<sup>165</sup> therefore requirements would have only marginal benefit. The commenter notes that EPA’s Control Techniques Guidelines for oil and gas do not include tank truck loading controls. Nonetheless, Utah already has regulations in place requiring a vapor capture line plus bottom filling or submerged fill<sup>166</sup> and EPA’s proposed Federal Implementation Plan (FIP) requires bottom fill or submerged fill for tank truck loading.<sup>167</sup> The commenter states that Utah’s crude oil has a very high wax content and pour points well above typical ambient temperatures and must be stored in tanks heated to approximately 160 degrees Fahrenheit. The commenter asserts that it would be impractical and impossible to directly pipe the liquid downstream in a standard nonheated pipeline because the wax would solidify at cooler ambient temperatures, rendering the crude oil impossible to pump. The commenter does not recommend heating the pipelines because it consumes additional energy resulting in greater greenhouse gas emissions. Moreover, the commenter references a recent study by three Utah Universities found that Utah crude oil could be mixed with condensate to improve pipeline pumpability but would still likely require the addition of chemical additives to serve as flow improvers or pour point depressants.<sup>168</sup>

Commenters (0599-MS, 0817-GPA) state that tank to truck loading regulation is not appropriate for a NSPS rule and should be left to states. The commenters assert that tank trucks should not qualify as stationary sources within the meaning of section 111 of the CAA. And these trucks are not affixed to any other stationary source such that it would qualify as an “affected facility” within any proposed NSPS. On that basis alone, the commenters believe that regulation is inappropriate.

In addition, the commenters (0599-MS, 0817-GPA) report that there is already significant regulation of these sources at the state level—where regulation appears much more appropriate—and additional regulation from the federal level appears unnecessary, unduly burdensome, and lacking any significant basis. If EPA insists on regulating tank to truck loading, the commenters recommend that EPA consider the cost and benefits associated with additional regulation where state requirements already exist. Further, the commenters recommend that EPA consider reviewing state requirements as a basis for any proposed NSPS regulation to ensure consistency between state and federal programs. The commenters note that Texas already maintains requirements for truck loading of condensate that does not need federal

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<sup>165</sup> See “2017 Uinta Basin Oil and Gas Emission Inventory” located on Utah Division of Air Quality website at <https://deq.utah.gov/air-quality/statewide-oil-gas-emissions-inventory> (accessed on January 9, 2022).

<sup>166</sup> Utah Administrative Code, R-307-504(4).

<sup>167</sup> Proposed FIP, proposed rule language for 49 CFR 49.4180, p. 3532.

<sup>168</sup> See “Characterization of Waxy Crude Oil in Pipelines”, 2014-2015 Final Report, authored by the Utah Energy Research Triangle Project (a collaboration between Utah State University, the University of Utah, and Brigham Young University); available on the Utah State University website at <https://www.usu.edu/binghamresearch/files/reports/Utah-Energy-Research-Triangle-Project-Final-ReportMarch-2015.pdf> (accessed on January 23, 2022).



supplementation. However, the commenter suggests that EPA could rely on the Texas framework in considering a potential federal regulation, if appropriate.<sup>169</sup>

#### ***18.3.4 Specific Tank Truck Loading Requirement Considerations***

Several commenters request that EPA consider specific technical issues and exemptions if EPA proposes requirements under the NSPS and/or EG.

##### **18.3.4.1 Technical Considerations**

Commenter (0808-API) states that options typically used to reduce emissions from truck loading include routing emissions to a process (*e.g.*, by installing a vapor recovery unit (VRU) or to a combustion device. The commenter reports that many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks. The commenter provides the following practical, technical and safety issues details and recommends that EPA consider these when evaluating potential truck loading emissions controls:

- When loading emissions are to be routed to an existing combustion control device, substantial design evaluation work may be required to ensure that use of existing control devices is feasible, and if not, to design and install an additional or larger capacity combustion device.
- Some older facilities do not have the pad size to safely locate an additional combustor dedicated to loadout controls (if needed). Changes to the pad size require state agency and landowner approval, which may not be obtainable. Additionally, local governments and landowners may further prohibit operators expanding the footprint of a facility.
- If truck loadout vapors are routed through the storage tanks onsite prior to combustion, a new design analysis may be needed, which may generate costly modifications to low-producing sites (*e.g.*, adding additional combustion control, larger combustors, change pipe sizing, etc.) in order to properly design the facility.
- Loadout truck drivers, who may not be familiar with truck loadout air emission equipment being used at these older low production facilities, will need additional training to safely use the new equipment. In many situations, the trucking company is a separate entity that may change over time from the producer.
- Older vintage buried and semi-buried tanks are not designed to work with truck loadout equipment.
- Truck loadout controls may introduce excess oxygen in the system requiring the installation of an independent vapor control system.
- There are potential safety issues with the introduction of an oxygen rich vapor stream into atmospheric tanks that have minimal headspace. A higher oxygen percentage in the vapor mixture increases the risk of the vapor igniting and causing a fire or explosion. In these cases, the installation of an independent vapor control system may be required.

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<sup>169</sup> Texas Commission on Environmental Quality, “Tank Truck Loading of Crude Oil or Condensate” (available at <https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/tank-truck-load.pdf>) (last accessed January 25, 2022).

- Loading controls should not be required for sites where tanks are not required to be controlled.
- Lower producing facilities may have infrequent truck loadings based on production decline. EPA must evaluate the cost effectiveness of a reasonable threshold of crude oil/condensate prior to requiring any controls. Some states do not require loading controls if the number of loadouts is below a certain threshold or if the site routinely transfers liquids via a pipeline.

Commenter (0831-AXPC) states that truck loadout controls are added to existing facilities by the addition of new vent lines to an existing combustor and/or installation and operation of an additional or larger capacity combustor at the applicable facility. The commenter asserts that this analysis may require substantial design evaluation work to ensure that the use of existing control devices is feasible, and if not, to design and install a new combustor control device. The commenter notes that there are significant concerns with redesign requirements for older facilities, training of haulers, availability of space for new required combustor/flares, and introduction of excess oxygen to the system if routed to tanks (generally because flare lines may be too small to accommodate the instantaneous volume from a truck load). The commenter adds that these requirements will have disproportional impact on low-liquid-producing sites with infrequent loading/unloading events.

Commenter (0585-KOGA) presents three options for EPA's consideration.

- Vapor balancing which is used to route the vapors displaced during material loading from the tank truck back to the storage vessel.
- Use of a closed vent system operating with a reduction efficiency of 95 to 99 percent. A vapor capture system is used and routed to a vapor recovery device (VRD) or VRU which uses refrigeration, absorption, adsorption, and/or compression.
- Directly pipe liquids downstream. By directly piping liquids downstream, no emissions from tank truck loading are released to the atmosphere.

Commenters (0599-MSD, 0817-GPA) provide details on the availability of VRUs as control devices, VRU safety and emissions concerns, and VRUs impracticability for truck loading operations.

The commenters (0599-MSD, 0817-GPA) are concerned that EPA misunderstands the availability of VRUs. In their discussion of truck loading, the commenters note that EPA assumes that approximately 50 percent of storage vessels will be controlled by a VRU. But while there are facilities that use VRUs as a way of reducing tank emissions, the commenter asserts that all of these facilities do not have the ability to control truck loading emissions. For example, transmission and storage facilities and gathering and boosting facilities using floating roof storage tanks may not have a combustion device on location for vapor balancing. Therefore, facilities that do not have a combustion device available to vapor balance the truck emissions will need an exemption from any mandate. Regarding transmission, for facilities *only* using a VRU, there are other configurations that may lead to noncompliance with a proposed rule despite controlled emissions.

The commenters (0599-MS, 0817-GPA) contend that VRUs can impose serious safety and emissions concerns in truck loading operations. Even where installed, the commenter states that a VRU is generally not a viable option due to the propensity to introduce oxygen into the system, causing serious safety concerns. Additional oxygen can also cause increased flaring, and by introducing oxygen into the gas gathering system, cause increased gas line purging. It is also not correct, in the commenter's experience, to assume that a tank controlled by a VRU allows vapor balancing to the truck. Loading condensate or other products back into the tank system controlled by a VRU only introduces oxygen back into the vent system, sending the product down the line and implicating both safety and emissions concerns. Indeed, across the midstream sector, the commenters report that many regulated entities will not even install a VRU because of the technical concerns regarding introduction of oxygen to the system.

The commenters (0599-MS, 0817-GPA) state that VRUs are not a practicable nor feasible control for truck loading operations because not all tanks using a combustion device or flare have the ability to run vapor balance line to a control device as the control device may not be adequately set up for controlling truck loading vapors. Although circumstances vary, the commenters recommend that these variables in configuration be considered in the cost analysis for controlling truck loading compared to actual reductions gained from any sort of retrofitting or combustion device installation.

Commenters (0599-MS, 0817-GPA) assert that any regulation of truck loading operations must be based on individual truck loading points, not an aggregate emissions determination. The commenters recommend that EPA consider the "affected facility" as the truck loading point. However, the commenters state that EPA should not base truck loading emissions and control requirements on the total aggregate truck loading emissions for an entire facility but should instead base applicability on an individual truck loading point as the regulated facility. Most importantly, the commenters contend that regulating in any different manner would fail to account for the fact that facilities often have a sump or tank on distant outskirts of a facility, not located near any production tanks where the operator would be able to control truck loading operations.

The commenters (0599-MS, 0817-GPA) state that it is common for facilities to have multiple truck loading connections. However, many connections are used infrequently, have low throughput (such as for slop oil), are used for water truck loading, or are not located at a point in the facility where operators could safely route vapor balancing lines to a control device.

Commenters (0599-MS, 0817-GPA) assert that a 95 percent efficiency requirement should not be applied to tank truck loading. The commenters note that because there are significant challenges for routing low flow to combustion devices, midstream tank truck loading operations are very different from bulk gasoline terminals, regulated under Subpart XX. For similar reasons, the commenters contend that midstream tank truck loading connections could not meet the 98.7 percent capture efficiency required under the regulations of Subpart XX. The commenters note that there is varying guidance on what sort of capture efficiency one can claim for the amount of vapors from the truck that are getting to a control device and combusting. As one example, the

state of Texas has guidance providing that if a truck tested and certified consistent with certain DOT requirements, the truck can only claim up to a certain amount of capture.<sup>170</sup>

The commenters (0599-MS, 0817-GPA) note that the proposed language, however, does not consider what requirements are in place for capture efficiency. A blanket 95 percent control requirement would be difficult for truck loading in certain circumstances and there is little guidance on acceptable capture efficiencies outside of DOT, and even the basis for DOT's efficiency standards is not clearly articulated.

Commenter (0599-MS) recommends a threshold requirement for control such as 200 tpy methane, as currently incorporated in Pennsylvania's General Air Quality Permits for oil and gas. The commenter notes that these general permits also recognized safety concerns with controlling truck loading with vapor balancing and allow a general control option of 95 percent.

Comment: Commenters (0599-MS, 0817-GPA) recommend that EPA set a minimum annual emission threshold before a NSPS is triggered, below which loading operations would be exempt, such as for storage vessels.<sup>171</sup> The commenters assert that any such threshold should be determined according to a cost-benefit analysis conducted by EPA. The commenters note that a potential-to-emit demonstration for applicability is one option, but there are others that could be considered, such as composition and/or throughput. This would focus any regulation on emissions larger than *de minimis*.

Likewise, the commenters (0599-MS, 0817-GPA) assert that rather than base regulation on the API gravity of the condensate, any regulation of truck loading should be based on an emission threshold and *not* composition. The commenters note the reality of emissions from truck loading and that relationship to API gravity makes regulation on this basis inappropriate. They add that it is also inappropriate as the emissions from tank to truck loading are caused by vapors from the previous truck load that remain to be displaced into the atmosphere, meaning that the API gravity at the regulated site may be different from the last hydrocarbon load the truck hauled. Furthermore, they explain that emissions from tank to truck loading are already going to be fairly low but if EPA attempts to regulate through a composition requirement (e.g., all condensate, all crude, etc.), for example, instead of an emission threshold, it would be difficult to install a control device or vapor balance to address the emissions. The commenters suggest that a minimum emission threshold would help exclude those truly infrequent sources and aid in compliance monitoring and enforcement.

The commenters (0599-MS, 0817-GPA) explain that such a minimum emission threshold addresses cost effectiveness and safety concerns with low flow loading. The commenters add that truck loading operations may be so infrequent that the installation and maintenance of

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<sup>170</sup> Texas Commission on Environmental Quality, "Air Permit Technical Guidance for New Source Review Loading Operations" 6–7 (Feb. 2021) (available at <https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/loading-guidance.pdf>) (last accessed January 25, 2022); see also 49 C.F.R. §§ 173.33, 180.407.

<sup>171</sup> The number of truck loads could be used as an alternative threshold triggering application of the NSPS. This is especially appropriate for operations in remote areas or connected to pipelines but that require tank truck loading on rare occasions. This would help exclude those truly infrequent sources and address cost effectiveness of regulating these rare occurrences.

control devices is impractical at low emission levels. Low flow conditions also pose technical challenges in conveying waste gas to a combustor without introducing ambient air to process vessels through infiltration or other means. This would introduce excess oxygen into the process, creating the risk of an explosion or fire. Further, the commenters note that excess oxygen exacerbates corrosion and presents a risk of potential loss of primary containment.

#### 18.3.4.2 Exemptions

Commenters (0599-MSD, 0817-GPA) recommend that EPA exempt operations that do not already have a combustion control device that would allow for vapor balancing. Alternately the commenters request that EPA provide a relatively prolonged effective date where these control devices are not available and introduce safety risks, practical issues, and feasibility concerns.

Commenter (0938-Texas Oil & Gas Association (TXOGA)) recommends that any tank truck loading operations requirement exclude trucks that are connected to an oil pipeline or that remain under a VOC tpy threshold (similar to other states). The commenter also recommends that EPA exclude water trucking in any such standard, due to issues with the operation of emission control devices for these units, which are complex and would not be cost-effective, given the low potential emissions benefit. The commenter contends that there are not enough flashing/breathing/working losses on water tanks to operate an emission control device to 95 percent destruction efficiency, which means that additional assist gas would be required; the effects of providing such gas have not been considered in the November 2021 Proposal.

Commenter (0782-BHE) recommends that truck loading emissions requirements apply only to upstream operations and not to the T&S segments. The commenter contends that EPA's information solicitation applies only to production operations upstream of T&S. If EPA intends to consider broader applicability, the commenter encourages EPA to define subject liquids, and exclude liquids loading with insignificant emissions. In addition, if EPA elects to broaden applicability to T&S, the commenter requests justification and support. The commenter notes that without the proposed regulatory text it is unclear what EPA is considering.

The commenter (0782-BHE) notes that losses from loading operations are primarily a function of the physical and chemical characteristics of the pipeline pigging liquids and condensate, scrubber/strainer liquids, and other liquid waste recovered or dropped out of the pipeline at the stations. For T&S, the commenter suggests the corresponding volumes, frequency of these operations, liquid volatility, and subsequent emissions do not warrant inclusion.

## **18.4 Other Emission Sources**

Response I-18-4: In the November 2021 proposal preamble<sup>172</sup>, the EPA provided the legal basis for the scope of the proposal, which was to propose revisions to the NSPS for currently regulated VOC and methane emission sources, and to include the regulation of additional oil and gas VOC and methane emission sources in the production, processing, transmission and storage segments of the industry; and to promulgate Emissions Guidelines (EG) to require states to regulate

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<sup>172</sup> 86 FR 63147, November 15, 2021.

methane emissions from existing sources in those segments. The EPA solicited comment on additional information on specific emission sources that the EPA was evaluating as potential new sources to regulate under the NSPS and EG. Those sources included abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations in the production, processing, and transmission and storage segments of the industry.

As provided below in section 18.4.1, the EPA received several comments on the proposal requesting that the EPA broaden the scope beyond the emissions sources and industry segments proposed by the EPA. Some of the comments expressed the need for EPA to provide oversight of all facilities involved in the transport of gas, from well pads to city gates and beyond, *i.e.*, all distribution lines and transmission lines. Some of the sources of concern expressed by the commenters are covered under the NSPS OOOOb and EG OOOOc (*i.e.*, well sites, compressor stations, gathering pipeline facilities, natural gas processing plant), while others do not fall within the scope of the source category (*i.e.*, pre-production, distribution segment, downstream emissions from transport). While many of the sources cited by the commenters are not within the scope of the NSPS OOOOb and EG OOOOc rules, they are covered by other air regulations under the Clean Air Act (CAA). For example, the EPA, in coordination with National Highway Traffic Safety Administration (NHTSA), has established greenhouse gas emissions and fuel economy standards for medium and heavy duty trucks manufactured in model years 2014-2018, and under Phase II of the rule, has finalized standards for medium- and heavy-duty vehicles through model year 2027 that will improve fuel efficiency and cut carbon pollution to reduce the impacts of climate change. The EPA has also proposed standards to further reduce harmful air pollutant emissions from light-duty and medium-duty vehicles starting with model year 2027.<sup>173</sup>

One commenter (see section 18.4.3) expressed that the EPA is missing a large emission source of methane emissions. Specifically, the commenter (0587-US Well Services, Inc. (USWSI)) urged EPA to (1) address pre-startup emissions and (2) require monitoring to obtain data to validate further the benefit of the use of electric motors powered by natural gas in the well drilling and fracturing process at the pre-production for sale phase of well site operations. While not within the scope of the NSPS OOOOb rule and EG OOOOc, pre-production electric motors powered by diesel fuel and natural gas in the well drilling fracturing process would generally be covered under the regulations for stationary reciprocating internal combustion engines (RICE). Emissions from stationary RICE are covered under 40 CFR part 63, subpart ZZZZ, 40 CFR part 60, subpart IIII and/or 40 CFR part 60, subpart JJJJ, depending on the specific stationary engine. Stationary RICE would not be covered under the proposed NSPS OOOOb and EG OOOOc requirements.

The Oil and Natural Gas source category includes the production, processing, and transmission and storage segments. (81 FR 35832-35833, June 3, 2016). Pre-production, distribution segment, and transportation downstream emission sources have not been covered by the NSPS historically and are not within the scope of the current NSPS OOOOb and EG OOOOc rules. The pollutants covered are VOCs, SO<sub>2</sub>, and methane. For sources within the scope of the Oil and Natural Gas source category that the EPA had sufficient information to conduct the requisite analyses and develop standards, the EPA has proposed standards and presumptive standards in the December 2022 supplemental proposal for the NSPS OOOOb and EG OOOOc.<sup>174</sup> The EPA did not

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<sup>173</sup> <https://www.epa.gov/regulations-emissions-vehicles-and-engines>.

<sup>174</sup> 87 FR 74702, December 6, 2022.

consider emission sources that were not within the scope of the source category and pollutants to be covered under the NSPS and EG.

With regards to abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations emission sources, one commenter (see section 18.4.4) recommended that EPA evaluate the costs and benefits of controlling emissions from these additional sources and that EPA propose supplemental standards to the extent that such controls are net beneficial. Other commenters stated that expansion of the rules to include these additional emission sources would be burdensome to regulated entities and regulating agencies, and that there is currently insufficient data to support developing new regulations for these emission sources (see section 18.4.2). The EPA did not evaluate the costs and benefits or propose emissions standards for pipeline pigging operations and related blowdown activities, and tank truck loading operations in the December 2022 supplemental proposal because the EPA had insufficient information to conduct an analysis to establish standards at this time. The EPA may consider regulation of these emission sources through a future action, including in the next 8-year review of the NSPS. However, for abandoned wells, as stated in section X.A. of the final preamble, the EPA is finalizing well closure requirements under the fugitives monitoring standards that were proposed for actively producing wells in the December 2022 supplemental proposal. The final well closure requirements will prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair. See RTC Volume II Chapter 4, section 4.1.6 (Well Closure Requirements) for response to comments on the well closure plan associated with the fugitive monitoring requirements. See 40 CFR 60.5397b(l) of NSPS OOOOb and 40 CFR 60.5397c(l) of EG OOOOc for the final well closure requirements.

The comment summaries referenced in the above response related to the scope of emissions sources covered under the NSPS and EG proposals are provided below.

#### ***18.4.1 Support Broadening Scope of the Rule to Include Additional Emission Sources***

Commenter (0414-Waterspirit) urges EPA to broaden the scope of the rule to include all facilities within the oil and natural gas supply chains resulting in a while cycle assessment wherein methane is reported from all facilities which enable the transport of methane from the well site to transmission pipelines (*i.e.*, interstate pipelines) and to distribution pipelines (*i.e.*, PSEG). The commenter suggests that leadership across agencies could assist in this opportunity for independent monitoring. The commenter contends that every facility along the entire network of pipelines (well sites, processing plants, holding pools, liquefaction plants, compressor stations, etc.) – emit methane into the air. The commenter states that thousands of facilities currently go unmeasured, many unreported entirely and some provide estimated emissions per the 100-year-old potency equivalent of carbon dioxide.

Commenter (0428-Private Citizen) recommends that EPA apply the November 2021 Proposal for methane emissions across all components and all facilities in the natural gas supply chain, starting from well sites, to the processing plants, to gathering pipeline facilities, to the distribution pipeline facilities and to the transmission end use direct customers, such as power plants. The commenter contends that this complete end-to-end methane emissions monitoring and reporting would provide a more accurate methane emissions from the natural gas supply

chain. The commenter urges EPA to ensure that even electric compressor stations are included, identified and reported in terms of methane emissions per year. The commenter further recommends that EPA require all natural gas transmission pipeline projects to additionally detail all upstream facilities in terms of current emissions and resulting increased emissions from the added capacity of the proposed project. The commenter believes that all capacity increases need to be detailed from well-site to the transmission pipeline project identified facilities proposed to be modified.

Commenter (1270-LWVUS) believes that the November 2021 Proposal represents a major step forward in limiting methane emissions from gas and oil well. However, the commenter also believes that some issues have not received sufficient consideration and need to be addressed in this regulation and/or a related regulation. The commenter recommends that EPA address downstream emissions from transport, distribution, processing and storage because these emissions are a major problem. The commenter understands EPA's decision to limit considerations of GHG emissions to only those emissions arising from well sites. The commenter hopes that rulemaking on downstream emissions can be completed in the near future, since these are believed to constitute 20 percent of total emissions.

Commenter (1414-SEP) contends that EPA's oversight of the emissions levels must include all facilities involved in the transport of gas, from well pads to city gates and beyond, *i.e.*, all distribution lines and transmission lines.

#### ***18.4.2 Insufficient Information Provided to Support Broadening Scope of the Rule to Include Additional Sources***

Commenter (0831-AXPC) has concerns about EPA's broad suggestion that it may regulate additional emission sources beyond those explicitly discussed in the Initial Methane Notice. The commenter states that they cannot provide informed comment on this topic without further information from EPA, to include both full analysis in the supplemental proposal and proposed regulatory text.

Commenter (0598-CER) believes EPA has not spent sufficient time developing the regulation to determine if the additional sources cited by EPA should be included in the regulation or omitted. The commenter believes that there is currently insufficient data to support developing new regulations for the proposed sources. The commenter recommends that EPA collect an appropriate volume of data and engage industry stakeholders prior to developing new regulations for the sources.

Commenter (0938-TXOGA) states that the public has not been given an opportunity to review and comment on data that would support establishing standards for abandoned wells, pipeline pigging operations, pipeline blowdowns, and tank truck loading sources. The commenter notes that any such proposal would necessarily include the data and analysis to support the proposed addition. As these sources are not included in the RIA for the proposed rulemaking, the commenter asserts that it will be important for EPA to conduct a complete analysis (as required by Section 307(d) of the Act) to support any future regulatory action.



Commenter (0742-ADEC) does not support addressing additional methane emission sources in this proposal. The scope and length of the November 2021 Proposal already makes compliance risk and uncertainty a very large reality and would overburden permit and compliance staff to try to deal with a widely varying set of disparate emitting devices. The commenter states that EPA has always limited proposals to single source categories; as an example, RICE engine emission standards do not expand to include a review of refinery production systems for sulfur limits of diesel fuel as well as the tank truck that brought the fuel from the loading rack.

Comment: Commenter (1270-LWVUS) believes better data on current methane emissions from oil and gas wells is needed to measure the efficacy of new regulations. The commenter asserts there is a strong need for EPA to financially support new studies on methane from gas and oil extraction, transport, storage, processing and use, and that EPA statistics are updated and promulgated in a timely manner to the scientific community and the public.

The commenter (1270-LWVUS) notes that current EPA literature indicates that 2.3 percent of the total volume of gas extracted will be lost through emissions on site and downstream as the gas goes through all the processes required to distribute it to its point of end-use. Many researchers consider this estimated percentage to be much too small. One recent study indicates that leakage from oil production is 90 percent greater than previously estimated and leakage from gas production is 50 percent greater.<sup>175</sup>

The commenter (1270-LWVUS) suggests that, with the proliferation of new equipment and with new approaches to handling data becoming available, the commenter believes that improved estimates may soon be possible and will be important for rulemaking on downstream emissions. The commenter recommends that EPA consider the many reports by independent citizens or groups who have identified leaks from pipelines and compressor stations. The commenter contends that following up on such reports will be useful in gaining more accurate data on the amounts of actual methane emitted through leaks along pipelines and at compressor stations.

### ***18.4.3 Pre-Production Emissions***

Commenter (0587-USWSI) believes that the November 2021 Proposal ignores the environmental impact of pre-production startup activity which is a significant source of methane and other emissions that can be eliminated or minimized. The commenter urges EPA to (1) address pre-startup emissions and (2) require monitoring to obtain data to validate further the benefit of the use of electric motors powered by natural gas in the well drilling and fracturing process at the pre-production for sale phase of well site operations. The commenter's experience and in-field data show that, though relatively short-term, such releases are significant. The commenter contends that monitoring of such emissions will not only provide wide-spread validation of their magnitude and significance but will also provide a basis and incentive for control, reduction or elimination of such emissions. The commenter and other well service providers have demonstrated that proven, effective technology exists to achieve reduction goals at the pre-production stage.

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<sup>175</sup> <https://www.seas.harvard.edu/news/2021/03/oil-and-natural-gas-production-emit-more-methane-previously-thought>.

The commenter (0587-USWSI) states that the data and analysis in the Report<sup>176</sup> included as an attachment to their comments demonstrates that significant environmental benefits can be achieved by regulatory attention to emissions integral to natural gas exploration and production at the pre-start up stage. The commenter further states that, as shown in the report, the well development process prior to startup of production for output sale is an additional source of pollution that can be reduced or eliminated with proven, feasible, and cost-effective existing technology.

The commenter (0587-USWSI) notes that the information contained in the Report should be used to develop monitoring methodologies and to identify constituents and information to be reported. The commenter suggests that the report of monitoring should specify the source of onsite power used (whether diesel, natural gas, or other) for drilling and fracturing purposes. They add that monitoring should not be limited to minimum time or pollutant volume thresholds and results should be reported separately for the period from commencement of well drilling to startup of production.

The commenter (0587-USWSI) informs that other well service providers use electric motors powered by natural gas instead of diesel and have achieved reductions of methane emissions as compared with use of diesel-powered equipment. The commenter provides the example of Evolution Well Services documented significant CO<sub>2e</sub> reductions in a study of Evolution's operations using electric fracturing technology (see "Emissions Study On EWS Electric Fracturing (see Attachment 2 of comment letter)).

The commenter (0587-USWSI) notes that EPA has already determined in the context of NSPS for production well operations (40 CFR Part 60, subpart OOOOa) that the use of recovered (associated) gas as an onsite fuel source is a viable compliance option to control emissions. The use of such gas to power the drilling and fracturing phase of well site development would assure that this recognized emissions control benefit would be extended.

#### ***18.4.4 Evaluation of the Costs and Benefits to Controlling Emissions from Additional Emission Sources***

Commenter (0842-NYU) recommends that EPA evaluate the costs and benefits to controlling emissions from these additional sources and propose supplemental standards to the extent that such controls are net beneficial. A cost benefit analysis reaffirms the principles of Executive Orders 12,866 and 13,563<sup>177</sup>—including that agencies should select regulatory alternatives that “maximize net benefits” while also accounting for distributive impacts and equity.

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<sup>176</sup> Robinson and Hordijk, “Clearing the air: the truth about diesel, dual-fuel, and electric hydraulic fracturing operations,” December 2020. (Attachment 1 (40 page paper) to commenter's letter; copyrighted) (Report; US Well Services).

<sup>177</sup> Memorandum on Modernizing Regulatory Review, 86 Fed. Reg. 7223, 7223 (signed Jan. 20, 2021; published Jan. 26, 2021).

## Chapter 19. State, Tribal, and Federal Plan Development for Existing Sources

### 19.1 General Comments on the Proposal for Existing Sources

Comment: Commenter (1382-NGUSA) supports the new requirements for states to develop plans to reduce emissions from existing sources, considering the safety and reliability of existing operations.

Conversely, the EPA also received several comments (0790-State AGs, 0793-PBPA, 0957-WCLG) that generally opposed EPA's proposed new presumptive standards and/or requirements to mitigate methane emissions from oil and natural gas existing sources. Examples of some of those comments are provided in the following paragraphs.

Commenter (0790-State AGs) states that while the CAA expects that EPA's regulatory efforts will show genuine respect for federalism and the role of the states, the November 2021 proposal does not. The commenter notes that states already regulate natural gas production and processing, so EPA should discount the minimal benefits from federal methane regulations like those in the November 2021 proposal given these state efforts.

Commenter (0790-State AGs) asserts that the November 2021 proposal imposes a series of direct burdens on the states that neither the CAA nor any other existing law permits. According to the commenter, the November 2021 proposal identifies only one potential implication for federalism—compliance costs, but EPA observes that the proposal “may” impose a burden on the states because of the “many hours of staff time” required to develop and implement the plans that the November 2021 proposal requires (citing *Federal Register*, Volume 86, page 63,261 (86 FR 63261)). The commenter indicates that these costs will burden states: Oklahoma, for example, has noted that the November 2021 proposal could subject hundreds of thousands of additional oil and gas facilities to more regulation; West Virginia estimates that implementation under EPA's preferred 2-year timetable could cost its environmental regulatory agency over \$278 million each year. The commenter adds that the November 2021 proposal does not contain any specific provisions explaining how EPA will help states bear these significant compliance costs. Commenter adds that these compliance estimates may undershoot actual costs, as other aspects of the November 2021 proposal—such as EPA's choice to declare any unloading event a “modification” that subjects the facility to new-source performance standards—makes it difficult to evaluate accurately the true reach of the proposal.

Commenter (0793-PBPA) states that neither Congress nor (until recently) EPA envisioned CAA section 111(d) being used to regulate whole sectors of the economy. According to the commenter, when EPA first established procedures and requirements for submittal of state plans for control of pollutants from existing facilities under CAA section 111(d), EPA stated that under section 111(d) “extensive control strategies are not required,” state plans would “be much less complex,” and “the number of designated facilities per state should be few” (citing 40 FR 53345, 1975). The commenter states that EPA has only rarely promulgated section 111(d) standards and only for industry-specific pollution issues like acid mist emissions from sulfuric acid plants. The commenter asserts that EPA's infrequent and narrow use of section 111(d) confirms that this

provision was understood to allow limited regulation of existing sources and that the provision was a secondary part of the overall statutory scheme.

Response I-19-1: See section IV.A (Statutory Background of CAA Sections 111(b), 111(d), and General Implementing Regulations) of the final rule preamble for a discussion of EPA’s authority to issue EG to reduce emissions from existing sources. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for CAA section 111(d) as well as through specific EG.

In response to comments that EPA’s regulatory efforts under the November 2021 Proposal do not “show genuine respect for federalism and the role of the states”, see section XIII.C.2 (State flexibilities) of the final rule preamble. The EPA clarifies that it is not finalizing a framework that demands the state plan be identical to the EG. Under the EG, and consistent with the cooperative federalism framework of CAA section 111(d), states have the prerogative to develop state plans and have flexibility to adopt standards that diverge from the presumptive standards finalized here (including by considering RULOF in the development of their state plans). However, the EPA specifies that the designated facilities and the regulated pollutants must be the same as the EG. Further, unless the state is invoking RULOF to justify a less stringent standard, the state must demonstrate its plan achieves the degree of emission limitation in the EG in order to be approvable.

In response to comments on compliance cost estimates and the commenter’s example pointing to “modification” for liquids unloading events under the NSPS OOOOb, based on comments received on the November 2021 Proposal, the December 2022 Supplemental Proposal for NSPS OOOOb specified that a modification to an existing well occurs when the definition of modification in 40 Code of Federal Regulations (CFR) 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing. The final rule maintains what was proposed in the December 2022 Supplemental Proposal. See discussion in sections IV.F.1, IV.F.3.a.i, IV.F.3.a.ii, and IV.F.3.a.iii of the December 2022 Supplemental Proposal preamble related to what EPA proposed as constituting a well affected facility/designated facility, and EPA’s request for comments regarding operational scenarios that would constitute a modification for liquids unloading operations. See section 6.4.1 (Applicability) of Volume II of this Response to Comment document (RTC) for comments and responses on the December 2022 Supplemental Proposal on the definition of a well affected/designated facility and what constitutes a modification under the NSPS OOOOb for liquids unloading operations. Lastly, see sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and what constitutes a modification for existing wells for liquids unloading operations.

With regards to comments that express concern over the burden that would be placed on states with the implementation of the EG, see section XVII.B (Paperwork Reduction Act) for EPA’s discussion on the estimated annual burden to states that would be associated with the final EG OOOOc collection of information (averaged over the first 3 years following promulgation).

The EPA does intend on working with tribes and states to develop plans tailored to the factors concerning the states. The plan development process, under which performance standards for existing sources are established within their jurisdiction and have the discretion to consider remaining useful life and other factors, is one that Congress established through the text and structure of CAA section 111(d). See discussions in section V.B.2.<sup>1</sup> and section V.B.3.<sup>2</sup> of the December 2022 Supplemental and section XIII of the final preamble and final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

The new standards will work hand-in-hand with new resources and programs in the Inflation Reduction Act, which will incentivize early implementation of innovative methane reduction technologies and support methane mitigation and monitoring activities. These efforts will achieve greater methane emissions reductions more quickly. For more information on the IRA, the Administration has created a guidebook that provides an overview of the clean energy, climate mitigation and resilience, agriculture, and conservation-related tax incentives and investment programs, including who is eligible to apply for funding and for what activities. See <https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/>.

Comment: Commenter (0842-IPI) states that regulating new sources, alone, without regulating existing sources at the same time, can perversely encourage existing sources to stay in operation longer than they otherwise would because new-source-only standards make constructing a new source relatively more expensive (and operating an old source relatively cheaper) than it would be if the level of regulation were consistent across all sources. Commenter notes that academics call the resulting distortion of retirement decisions the “old plant effect,” and it can significantly extend the operating lives of highly polluting facilities. Commenter asserts that by coordinating regulation of new and existing sources, EPA laudably mitigates the potential for such distortion.

In contrast, commenter (0793-PBPA) states that existing source standards should not be “co-proposed” with new source standards but should instead be informed by already-finalized new source standards and made less stringent as necessary to accommodate “other factors,” such as the remaining useful life of existing sources. According to the commenter, EPA previously proposed to require that existing source standards be proposed simultaneously with new source performance standards, but EPA ultimately declined, in part because “proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance” would allow “the Agency [to] benefit from the comments on the standard of performance in developing the emission guideline” (citing 40 FR 53340, 533345, November 17, 1975). Commenter states that if EPA proceeds as proposed, the opportunity to have the EG informed by the process of developing and implementing the new source performance standards (NSPS) would be lost, leaving EPA to take a one-size-fits-all approach through enacting existing source standards that largely mirror the new source standards. Accordingly, commenter suggests that EPA wait to propose the EG until after it finalizes the proposed NSPS so that it will have a basis to account

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<sup>1</sup> 87 FR 74812.

<sup>2</sup> 87 FR 74816.

for useful life and “other factors” that compel tailored existing source standards, particularly because the EG will have a far greater impact on the oil and gas sector because there are far more existing sources than there are new sources subject to the NSPS program. Commenter adds that EPA’s patience would also allow it to consider the Department of Energy’s impending study on methane emissions from marginal oil and gas wells, which could address EPA’s stated concern that there are a large number of existing well sites that “are not complex” and that therefore should be treated differently from a fugitive emissions standpoint.

Response I-19-2: For the comment that supports regulating new and existing sources at the same time, this is a supportive comment of EPA’s Proposals and the Final Rule which establishes oil and natural gas affected facility standards for new sources and designated facility presumptive standards for existing sources; as such, no response is required.

For the comments that opposed regulating new and existing sources at the same time, please see section IV.A (Statutory Background of CAA Sections 111(b), 111(d), and General Implementing Regulations) of the final rule preamble for a discussion of EPA’s authority to issue EG to reduce emissions from existing sources. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for CAA section 111(d) as well as through specific EG.

Also, as discussed in Response I-19-1 of this Chapter, under the EG, and consistent with the cooperative federalism framework of CAA section 111(d), states have the prerogative to develop state plans and have flexibility to adopt standards that diverge from the presumptive standards finalized here (including by considering RULOF in the development of their state plans). However, the EPA specifies that the designated facilities and the regulated pollutants must be the same as the EG. Further, unless the state is invoking RULOF to justify a less stringent standard, the state must demonstrate its plan achieves the degree of emission limitation in the EG in order to be approvable.

In response to comment that refers to the U.S. DOE study of emissions from low production wells, see EPA’s response to similar comments and EPA’s review of the study in section XI.A.1.d (Subcategorization of well sites) of the final rule preamble.

## **19.2 Rulemaking Process**

### ***19.2.1 EPA Rulemaking under CAA Section 111(d)***

Comment: Commenter (0922-NAM) provides comments regarding EPA’s authority under CAA section 111(d) to develop presumptive standards for the regulation of methane emissions from oil and natural gas operations.

Commenter (0922-NAM) states that any future rule can only include a best system of emission reduction (BSER) and provide for the development of standards of performance focused on what

can be accomplished at the source level. The commenter points out that the text of CAA section 111 mandates this source-specific approach, quoting the definition of “stationary source” found therein. The commenter notes that the regulations implementing CAA section 111(d) confirm this source-specific standard setting focus in this proposed rulemaking, and the commenter commends this following of the law. The commenter adds that until the judicially stayed Clean Power Plan in 2015, the EPA had in place regulations for five source categories under section 111(d), and in each of those the Agency had uniformly developed a BSER for the source category used to develop source-specific performance standards.

Commenter (0922-NAM) states that any existing source rule should set the BSER but leave it to individual states to set the standards of performance and then to sources to select compliance pathways. The commenter supports the EPA’s position, as stated in the November 2021 proposal, that the Agency determines the BSER. The commenter notes that this approach is clearly laid out in CAA section 111(d)(1), which also mandates that each state is to develop a state plan that establishes standards of performance for existing sources. The commenter points out that the existing source implementing regulations confirm this division of responsibility between the federal and state governments, where the federal EG reflect the BSER but do not include emission standards, and the state plans must include emission standards. The commenter believes that CAA section 111(d) further reinforces this by providing that states are the entities that apply a standard of performance to any source and are entitled to adjust the standard to account for the individual circumstances of the source.

Commenter (0922-NAM) states that EPA’s central task in any future rules should be to establish an appropriate BSER. Commenter notes that CAA section 111 requires EPA to determine that a system of emission reduction has been “adequately demonstrated” before it can be designated as the BSER. The commenter adds that the United States (U.S.) Court of Appeals for the District of Columbia (D.C. Circuit) has determined that “[a]n adequately demonstrated system” “has been shown to be reasonably reliable, reasonably efficient, and...[not] exorbitantly costly in an economic or environmental way” (citing *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Circuit 1973)), and that while EPA “may make a projection based on existing technology that projection is subject to the restraints of reasonableness and cannot be based on ‘crystal ball’ inquiry” (citing *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Circuit 1973) (addressing NSPS for new or modified Portland cement plants), superseded in part by statute, 15 U.S.C. 793(c)(1) (1974), as recognized in *Am. Trucking Ass’ns v. EPA*, 175 F.3d 1027 (D.C. Circuit 1999)).

Commenter (0922-NAM) believes that the EPA should ensure that any final rule for existing sources does not establish guidelines stricter than standards set for new sources under CAA section 111 for a given source category. According to the commenter, the statutory text and structure confirm this limitation in that section 111(d) only permits the establishment of standards of performance for existing sources “to which a standard of performance would apply if such existing source were a new source.” The commenter asserts that by making regulation of existing sources contingent upon the regulation of new sources, Congress demonstrated an unambiguous intent to make CAA section 111(d) a supplementary program. The commenter states that this approach allows any CAA section 111(d) regulation to be informed by the BSER analysis and standards of performance for new sources, although the statute provides additional

flexibility for existing sources considering cost-related and other issues associated with existing source retrofits—concerns that do not apply to new sources.

Response I-19-3: Please see section IV.A (Statutory Background of CAA Sections 111(b), 111(d), and General Implementing Regulations) of the final rule preamble for a discussion of EPA’s authority to issue EG to reduce emissions from existing sources. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for CAA section 111(d) as well as through specific EG.

### ***19.2.2 Supplemental Proposal/Regulatory Text for the EG***

Comment: Commenter (0820-PNR) appreciates that EPA has acknowledged that the November 2021 Methane Rule publication does not constitute a complete proposed rule, as evidenced by EPA’s stated commitment to issuing a supplemental proposal that will contain the proposed regulatory text for new subparts NSPS OOOOb and EG OOOOc. The commenter strongly supports the issuance of a supplemental proposal and urges EPA to make the scope of that supplemental proposal, and the subjects on which it solicits comment, as broad as possible. The commenter believes that it would be poor policy and not good governance to narrowly restrict the scope of comment on the supplemental, particularly because EPA has not yet shown the public what regulatory text it proposes to codify nor the policy intentions it discusses with respect to these subparts in the preamble of the November 2021 publication. The commenter looks forward to reviewing the proposed regulatory text, as well as to any additional information and solicitation of comment that EPA includes in the supplemental proposal.

Response I-19-4: The EPA disagrees with the commenter accretion that the November 2021 proposal was not complete. As stated in the December 2022 supplemental, EPA CAA section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text. Similarly, the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register. Section 553(b)(3) of the APA provides that a notice of proposed rulemaking shall include “either the terms or substance of the proposed rule or a description of the subjects and issues involved.” (Emphasis added). Thus, the APA clearly provides flexibility to describe the “subjects and issues involved” as an alternative to inclusion of the “terms or substance” of the proposed rule. See also *Rybachek v. EPA*, 904 F.2d 1276, 1287 (9th Cir. 1990) (the EPA’s “failure to propose in advance the actual wording” of a regulation does not make the regulation invalid where the “proposal . . . clearly describe[s] ‘the subjects and issues’ ” involved).<sup>3</sup>

On December 6, 2022, the EPA proposed regulatory text for NSPS OOOOb at Document I.D. No. EPA-HQ-OAR-2021-0317-1551 and EG OOOOc at Document I.D. No. EPA-HQ-OAR-2021-0317-1552 in the public docket. The December 2022 Supplemental offered stakeholders an

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<sup>3</sup> 87 FR 74716.



additional opportunity engagement through a second round of public comment and held an additional three-day virtual public hearing on January 10, 11, 12, 2023.

Comment: Commenter (0424-WVDEP) disagrees with the assertion that the EPA satisfied its requirements under Code of Federal Regulations, title 40, part 60 (40 CFR part 60), subpart Ba by including description in four separate locations in sections X, XI, and XII of the November 2021 proposal preamble and the *Background Technical Support Document (TSD) for the Proposed New Source Performance Standards (NSPS) and Emission Guidelines (EG)* located at Docket ID No. EPA-HQ-OAR-2021-0317 because the EPA did not provide any proposed regulatory text. Commenter asserts that this is a piecemeal approach to a proposed rulemaking without providing proposed regulatory text, which absolutely does not meet the EPA's obligation under 40 CFR 60.22a(b).

Response I-19-5: EPA's November 2021 proposal satisfied the requirements applicable to draft emission guidelines within 40 CFR Part 60 Subpart Ba that existed at the time of the November 2021 proposal. EPA explained how it met each component of 40 CFR 60.22a(b), and included cross references to where within the proposed rule materials that information could be found. 86 FR 63110, 63248 – 63249 (November 15, 2021). The fact that EPA satisfied these requirements via the compilation of information that was located in various sections of the proposal and associated documents does not negate the fact that EPA complied with these requirements. EPA provided a clear roadmap to readers to demonstrate how the Agency met those requirements. Lastly, contrary to the commenter's suggestion, the provision cited by commenter, 40 CFR 60.22a(b), does not contain a requirement that EPA publish draft regulatory text for the emission guidelines.

Comment: Several commenters (0431-NOI, 0465-JDC, 0411-REM) express that the EPA did not propose NSPS OOOOb/EG OOOOc regulatory text. Small business entities with minimal staff and limited resources need direct, well-defined, and easily understood proposed regulations to evaluate for impacts and provide meaningful comment. Further, commenters note that approximately 1000 pages of preamble and technical support documents were published by the EPA with a limited response time of 77 days encompassing two major holidays. The commenter (0465-JDC) notes that this prevented them from fully deciphering and commenting on the potential short-term and long-term implications of proposed regulations. Another commenter (411-REM) notes that commenters are interpreting the proposed rules differently.

Commenters (0581-NACAA, 0813-BIHE, 0827-WESTAR) advise EPA to meet with state, tribal, and/or local air agencies to guide development of the EG regulatory text for the supplementary proposal.

Commenter (0581-NACAA) states that to achieve the cooperative potential of the CAA section 111(d) program, it is essential that EPA consult with state and local air agencies as it develops its supplemental proposal and its proposed rule concerning the implementation of section 111 programs. The commenter asserts that state and local air agencies charged with implementing the rule have unique regulatory expertise and are leaders in the arena of GHG emission reduction programs; in particular, in reducing methane from the oil and gas sector. The commenter notes that their January 15, 2021, transition letter calls for EPA to "mine the knowledge of state and

local regulators and apply it to the development of nationally consistent federal rules to reduce GHG emissions from industrial and other stationary sources regulated under the Clean Air Act.” The commenter notes that the CAA and section 111(d) are built on a model of cooperation that requires EPA to work in partnership with states, cities, and counties, among others, and by affording states additional – and essential – flexibility to chart compliance pathways, which can include emission limitations that are at least as stringent as the federal guidelines. The commenter requests that EPA retain its longstanding reliance on mandatory federal minimums coupled with state implementation flexibility to meet or exceed those environmental goals.

Commenter (0827-WESTAR) states that before proceeding with the proposed rulemaking activities, they suggest that EPA talk with individual state, tribal, and local air programs, document what was learned, and fully map the landscape of how methane and other emissions are controlled and managed. According to the commenter, a plan to meet with state, tribal, and local air programs; an effort to comprehensively gather necessary information; and the conduct of analyses adequately addressing the control concepts proposed are all necessary steps to developing effective and efficient regulations. Given that there was no detailed regulatory language in this proposal, the commenter requests that EPA provide ample time for public comment and engagement when the actual regulatory language is proposed, which will allow the state, tribal, and local air programs to provide more substantial comment and input based upon their experience and knowledge.

Commenter (0827-WESTAR) also asks that EPA equally address emission sources under its purview as the rulemaking process would require state, tribal, and local air agencies to do their parts, by also fully quantifying, tracking, and managing EPA-controlled existing emissions and control effectiveness in the context of this rulemaking proposal.

Commenter (0813-BIHE) encourages EPA to work cooperatively with states to ensure any new regulations for existing oil and gas sources are reasonable and effective, noting that additional regulatory burden without realized benefit is neither helpful to industry or the public, nor a valuable use of EPA’s time and resources.

Response I-19-6: With regards to comments about EPA proposing regulatory text and opportunities for engagement with EPA, please see Response I-19-4 within this Chapter.

EPA reviewed public comments on the November 2021 Proposal from various states, tribes, and other stakeholders. These comments helped to inform EPA’s December 2022 Supplemental Proposal which included additional details for how states would implement the EG through the development of state plans. EPA continued dialogue with various state and tribal agencies throughout the development of the 2021 proposal and 2022 supplemental proposal.<sup>4</sup> In EPA’s 2021 TSD<sup>5</sup> EPA identified existing federal, state, and local regulations to help inform the development of the EG which the EPA proposed to refine in the 2022 supplemental TSD.<sup>6</sup>

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<sup>4</sup> For example, see Document I.D. Nos. EPA-HQ-OAR-2021-0317-0117, EPA-HQ-OAR-2021-0317-1474, EPA-HQ-OAR-2021-0317-1527, EPA-HQ-OAR-2021-0317-1510, and EPA-HQ-OAR-2021-0317-1524.

<sup>5</sup> See document I.D. EPA-HQ-OAR-2021-0317-0166.

<sup>6</sup> See document I.D. EPA-HQ-OAR-2021-0317-1578.

With regards to commenters request that EPA equally address emission sources under its purview by fully quantifying, tracking, and managing EPA-controlled existing emissions and control effectiveness, the EPA believes that we have accomplished that as presented in the Final TSD located in Docket No. EPA-HQ-OAR-2021-0317. Furthermore, the EPA has an obligation to promulgate a Federal plan if a state fails to submit a satisfactory plan. To the extent the commenter is requesting that EPA “equally address emission sources” in a federal plan, EPA notes that any such federal plan would be promulgated via a separate rulemaking process in the future.

EPA is committed to work cooperatively with states and tribes to ensure any plans submitted meet the necessary completeness criteria.

### ***19.2.3 Development of a Model Rule***

Comment: Commenters (0456-WDNR, 0581-NACAA, 0782-BHE) support development of a model rule by EPA.

Commenter (0456-WDNR) states that model rule language is critical for states without existing state programs regulating the oil and natural gas sector. Commenter (0581-NACAA) supports the development of an example state plan and model rule language for each segment of the oil and gas industry regulated by adopted rule that can be incorporated directly or by reference to meet EPA’s emission guidelines, believing that many agencies will benefit from a model rule. Commenter (0581-NACAA) adds that the opportunity to adopt preapproved rule language, in addition to the option to develop a unique state plan in accordance with the guidelines, is consistent with the CAA’s cooperative approach and will expand state compliance options while conserving state resources.

Commenter (0782-BHE) recommends that the EG include a model rule or example regulatory text for the states to consider that includes provisions that allow case-specific review analogous to alternative reasonably available control technology (RACT) provision in ozone state implementation plans (SIPs) and consideration of case-specific economic and technological feasibility.

Response I-19-7: The EG OOOOc regulatory text includes a model rule which is reflected in §§60.5385c through 60.5430c.<sup>7</sup> A proposed model rule was available in the public docket for public comment in conjunction with the 2022 supplemental proposal.

## **19.3 Presumptive Standards**

### ***19.3.1 General Comments on Presumptive Standards***

Comment: Commenter (0797-NDDEQ/IC) asserts that EPA lacks authority to establish standards of performance for existing sources under CAA section 111(d), which mandates that the states have the authority to set the standards of performance and emission limitations, and further

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<sup>7</sup> See Document I.D. No. EPA-HQ-OAR-2021-0317-1552 in the public docket.

mandates that the states have the authority to make source-specific determinations in setting those standards of performance “for any existing source.” The commenter argues that any BSER guideline created by EPA must not infringe on the states’ authority to establish emission limitations and determine what emission limitations are “achievable” by existing sources, including the states’ authority to take source-specific factors into account in establishing the standards of performance. For example, the commenter believes that the November 2021 proposal violates this statutory separation of authority by proposing a fixed national standard of 95 percent VOC emissions reduction that would apply to both new and existing pneumatic controllers, asserting that EPA’s proposal to assume for itself the authority to impose fixed national emission standards on existing sources and thus displace the state’s authority to establish standards of performance for existing sources violates CAA section 111(d).

Commenter (0797-NDDEQ/IC) further argues that EPA’s attempt to label this 95 percent VOC emission reduction requirement as a “presumptive standard[] that States may use in the development of State plans for specific designated facilities” is a misnomer (citing 86 FR 63117). According to the commenter, this action, if finalized, would displace North Dakota’s sovereign authority to apply the BSER guidelines to determine the degree of emission limitation that is achievable, because EPA has already made that determination.

Commenter (0797-NDDEQ/IC) notes that this very issue is currently before the Supreme Court in *North Dakota v. EPA et. al.*, No. 20-1780 (Consolidated in Case No. 20-1530 with Case Nos. 20-1531 and 20-1778), where certiorari has been granted and oral argument is set to proceed on February 28, 2021. The commenter reports that one of the key issues the Supreme Court will soon rule on is the extent of EPA’s authority under CAA section 111(d) to impose emissions standards on existing sources. The commenter asserts that EPA should refrain from proposing and finalizing any regulatory provisions regarding existing sources in this rulemaking until the Supreme Court issues its decision.

Commenter (0790-State AGs) states that the November 2021 proposal ignores its consequences for federalism in creating presumptive standards for existing sources. According to the commenter, CAA section 111(d) contemplates that states will have more latitude to implement standards of performance than when EPA takes up this task—as where the statute says that states may consider a facility’s “remaining useful life”—but EPA instead notes that “it would likely be difficult for states to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities” (citing 86 FR 63251). Given this, commenter believes that the November 2021 proposal would give states little choice but to implement the measures that comprise EPA’s BSER—lest EPA reject the states’ plans entirely. Commenter states that even then, EPA offers little reassurance to states, specifying that EPA still might not approve state plans that track the presumptive standards (citing 86 FR 63249), leaving states with trying to comply with EPA’s “presumptions” while hoping that EPA does not take the matter out of the states’ hands entirely.

Response I-19-8: EPA did not propose to establish standards of performance for existing sources. EPA is not finalizing any standards of performance that apply to existing sources. The presumptive standards are not “fixed national standards” as one commenter suggests, because they do not directly apply to any sources. In accordance with Section 111(d) of the Clean Air Act

(CAA), states are tasked with developing plans which establish standards of performance for existing sources. However, in accordance with EPA regulations, the agency is to publish emission guidelines (EG), and those guidelines are to include certain information. 40 CFR 60.22a. Among other information, the EG must include “[t]he degree of emission limitation achievable through the application of the best system of emission reduction (considering the cost of such achieving reduction and any nonair quality health and environmental impact and energy requirements) that has been adequately demonstrated for designated facilities.” Id. 60.22a(b)(5). The presumptive standards that commenters take issue with are a product of EPA’s compliance with its own regulations and are intended to assist states with the development of their plans. These presumptive standards do not deprive states of their authority to establish standards of performance, to make source-specific determinations, or to consider remaining useful life and other factors. States are not required to adopt the presumptive standards and are free to pursue a different approach in their state plan so long as their approach comports with applicable laws, regulations, and guidance.

The EPA is finalizing, for this EG, to translate the degree of emission limitation achievable through application of the BSER (i.e., level of stringency) into presumptive standards of performance that States may use in the development of State plans for specific emission points. The EPA believes that the presumptive standards of performance included in the EG will provide States with the level of stringency that the EPA would require to approve a State plan. Put another way, the EPA is choosing to format this EG such that if a State chooses to adopt the presumptive standards as the standards of performance in their State plan, then the EPA believes that such plan could be approved as meeting the requirements of CAA section 111(d) and the finalized EG, assuming the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a similar purpose as a model rule because they are intended to assist States in developing their plan submissions by providing the States with a starting point for their standards that are based on general industry parameters and assumptions. Some commenters have specifically requested that EPA provide this starting point. See comments and responses in section 19.2.3 of this Chapter. The EPA believes that providing these presumptive standards of performance will create a streamlined approach for States in developing plans and for the EPA in evaluating State plans. Of course, the EPA cannot predetermine the outcome of a future rulemaking process, and inclusion of these presumptive standards in this EG does not impact the rulemaking process associated with the EPA’s review of, and action on, a State plan submission. In its review of State plans, the EPA will consider the information in the final EG and the final presumptive standards, as well as information submitted by the State and the public. The EPA will evaluate the approvability of all plans through individual notice-and-comment rulemaking processes.

Further, EPA recognizes that the general industry parameters and assumptions underlying the presumptive standards may not be applicable to all sources in all situations. EPA acknowledges that a state may be able to establish an approvable standard of performance that differs from the presumptive standard. The inclusion of presumptive standards does not automatically foreclose this possibility.

Further, the EPA finalized provisions at 40 CFR part 60 subpart Ba to guide states that choose to apply a standard of performance to a particular source, to take into account the source’s

remaining useful life and other factors. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023). The EPA's final EG issued under CAA section 111(d) do not impose binding requirements directly on sources, but instead provide requirements for States in developing their plans and criteria for assisting the EPA when judging the adequacy of such plans.

Finally, with respect to the challenge the commenter cites that was then-pending before the Supreme Court, the Court confirmed EPA's authority to establish the BSER and degree of emission limitation for existing sources: "Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d). [t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved." *West Virginia v. EPA*, 142 S. Ct. 2587, 2601-02 (2022).

### ***19.3.2 Proposed Numerical Presumptive Standards***

Comment: Commenters (0558-CCES, 0761-Exelon, 0793-PBPA, 0832-NMED, 1267-CA) state that EPA should allow states to adopt standards that take a different form than the "presumptive" numerical standards that EPA has proposed, if states can demonstrate equivalency. Commenter (0793-PBPA) states that this should be allowed out of respect for cooperative federalism and each state's on-the-ground expertise, given that CAA section 111(d) only requires EPA to "establish a procedure" under which each state can submit state plans, as opposed to requiring EPA to establish "presumptive" numerical standards. Commenter (1267-CA) similarly notes that allowing states to adopt a different form of the presumptive numerical standard is more consistent with the structure of CAA section 111(d), under which states have wide latitude in developing their plans provided that the required level of emission reduction is achieved, although the commenter understands the desirability of streamlining the preparation of state plans and simplifying EPA's review of those plans. Commenter (0761-Exelon) indicates that this should be allowed unless any facts and circumstances that are unique to the type of designated facility make the proposed form of the standard the only appropriate form. Commenter (0832-NMED) recommends that the EPA provide a streamlined demonstration of equivalency if state rules already require meaningful, cost-effective GHG and VOC emission reductions, noting that New Mexico just completed a multi-year comprehensive rulemaking process and has proposed a nationally leading regulation covering both new and existing oil and gas sources.

Response I-19-9: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>8</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0824-WDEQ) states that the November 2021 proposal's state plan requirements should be reconsidered. The commenter notes that EPA solicited comment on whether it should allow states to include a different form of numerical standards, but commenter believes that the establishment of a uniform standard does not account for the technical intricacies and site-specific conditions at each individual affected facility – and it also does not account for the feasibility or infeasibility for certain operators to achieve the standard. The commenter asserts that it is imperative that states have sufficient input on setting standards of

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<sup>8</sup> 87 FR 74812.

performance that are both achievable and enforceable, and EPA should consider comments it receives that point out the technical concerns with achieving uniform standards - whether they are numeric or non-numeric.

Response I-19-10: See discussion in section V.B.2 (Leveraging State Programs)<sup>9</sup> and discussion in section V.B.3 (Remaining Useful Life and Other Factors (RULOF))<sup>10</sup> of the December 2022 Supplemental Proposal preamble; and sections XIII.C.2 (State flexibilities) and XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble.

See also Response I-19-9 of this Chapter.

Comment: Commenter (0938-TXOGA) states that in the development of presumptive standards for existing sources, EPA must not undercut the flexibility allowed in the site-specific alternate means of emissions limitation (AMEL) process for new sources and allow the application of site-specific AMELs to an existing source by operation of law. Commenter supports EPA's continued use and development of a more streamlined and improved AMEL process and fears, based on EPA's proposal to require standards in state plans to be of the same form as the numerical presumptive standards, that facilities obtaining AMEL approval for new sources would not be able to apply that same AMEL to existing sources subject to the EG. The commenter states that this proposal could be misinterpreted to mean that states would not have the flexibility under their plans to allow an AMEL that EPA has approved for NSPS OOOO, NSPS OOOOa, or NSPS OOOOb, even where a site contains new and existing facilities, and that states could not include in their own state plans the ability to approve AMELs themselves. The commenter indicates that while this may not be the intent, it is important for the regulations to be written to avoid such a result, and EPA should ensure that it has not cemented the "floor" for the EG in a manner that would preclude application of AMELs for existing sources. The commenter notes that as an AMEL must demonstrate at least an equivalent reduction in emissions for a new source, there is no basis to preclude their use for existing sources.

Commenter (0938-TXOGA) requests that EPA ensure its proposed regulations (when published) address this issue so that sources with an approved site-specific AMEL may employ that AMEL with respect to new, modified, and reconstructed affected facilities at a site and to existing designated facilities subject to EG OOOOc. Specifically, the commenter asserts that EPA should draft the proposed regulations consistent with the following principles:

1. If there is an approved AMEL for NSPS OOOO, NSPS OOOOa, or NSPS OOOOb, the AMEL should be deemed approved under state plans that track the requirements of the new source standards (in form or stringency).
2. State plans should not need to be amended to allow use of AMELs approved by EPA under NSPS OOOO, NSPS OOOOa, or NSPS OOOOb, regardless of when such approval occurs. The commenter is concerned that the "double-key" approach of SIP approvals, which has led to substantial backlogs for SIPs, not be replicated in this context.

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<sup>9</sup> 87 FR 74812.

<sup>10</sup> 87 FR 74816.

3. Finally, states should have the authority to approve AMELs, without concurrent EPA approval (not the two-step process like for SIPs).

Response I-19-11: The AMEL provision in the Clean Air Act has been applied only in the context of new source performance standards issued under CAA section 111(b). See CAA 111(h)(3). CAA section 111(d) does not specifically incorporate the AMEL provision from 111(h)(3). EPA's rule promulgated under 111(b) does allow for AMEL for new, modified, and reconstructed sources. Further, states are free to consider site-specific factors when establishing standards of performance in their state plans regulating existing sources. If a state plan includes a standard that is different than the presumptive standard included in EPA's emission guidelines, and the state believes their standard will achieve emission reductions that are equivalent to or greater than the emission guidelines, then the state plan should explain why they believe this. EPA anticipates that such an explanation would be very similar in nature to an AMEL, but this is not the same as an AMEL application under CAA 111(h)(3). Further, if EPA approves an AMEL request in the context of the NSPS, that does not automatically mean that existing sources are allowed to make use of that AMEL. First, the AMEL provision only applies in the context of non-numerical standards under 111(h). Second, AMEL approvals can be site-specific in which case the approval would only apply to listed sources/sites, or perhaps similarly situated sources. Third, states establish standards for existing sources via the state planning process. Even if EPA were to approve a broadly-applicable AMEL request in the context of the oil and gas NSPS, a state would need to amend its state plan to allow existing sources in that state to make use of such an AMEL. States are free to amend their state plans as they see fit, but those revisions must be submitted to EPA for evaluation and action. If after approval of a state plan, a state determines there is another equivalent method to reduce emissions, whether EPA approved an AMEL for that new way or not, the state is free to amend their plan to include it. Lastly, the commenter is correct that states cannot allow for approval of AMEL for existing sources in their plan without EPA approval.

While states do not have the delegation authority to approve AMEL themselves, states have flexibility in the state planning process as discussed in section V.B.2 (Leveraging State Programs)<sup>11</sup> and in section V.B.3 (Remaining Useful Life and Other Factors (RULOF))<sup>12</sup> of the December 2022 Supplemental Proposal preamble; and sections XIII.C.2 (State flexibilities) and XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble.

As noted in the proposed §60.5373c, authorities that will not be delegated to a state, local, or tribal agency includes approval of alternatives to the emission limits and standards, approval of major alternatives to test methods, approval of major alternatives to monitoring, approval of major alternatives to recordkeeping and reporting, approval of an alternative to any electronic reporting to the EPA required by this subpart and performance test and data reduction waivers.<sup>13</sup>

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<sup>11</sup> 87 FR 74812.

<sup>12</sup> 87 FR 74816.

<sup>13</sup> See Document I.D. No. EPA-HQ-OAR-2021-0317-1552 in the public docket.



### ***19.3.3 Proposed Non-Numerical Presumptive Standards***

Comment: Commenter (1267/1268/1269-CA AG et al) concurs with the approach that each state adopt the proposed presumptive standards or otherwise demonstrate that the state's alternative approach will achieve reduction in methane emissions at least equivalent to that of the presumptive standards.

Response I-19-12: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (0761-Exelon) states that even if states adopt the presumptive standards in their plans, states would still be able to include flexible compliance mechanisms based on consideration of a designated facility's "remaining useful life" and other source-specific factors.

Response I-19-13: See discussion in section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble. See also the final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023.

### ***19.3.4 More Stringent State Standards***

Comment: Commenters (0808-API, 0834-AAC, 0921-USCoC, 0938-TXOGA) state that EPA's proposed position that it has authority to approve, and make federally enforceable, state standards that are more stringent than the presumptive standards included in the final EG is not supportable under the law. Commenters (0808-API, 0834-AAC) note that CAA section 111(d)(1) requires states to develop "standards of performance" for existing affected facilities, and that the term "standard of performance" is defined in CAA section 111(a)(1) to mean an emissions standard "which reflects the degree of emission limitation achievable through the application of the best system of emissions reduction ... the Administrator determines has been adequately demonstrated." Commenter (0921-USCoC) states that CAA section 111(d) is fundamentally distinct from the SIP process under CAA section 110 in that section 111(d) does not prescribe minimum conditions but instead requires standards of performance that reflect BSER as determined by the Administrator. Commenter (0834-AAC) concludes that this means that state standards of performance must be based on BSER as determined by EPA. Commenters (0808-API, 0921-USCoC, 0938-TXDOGA) conclude that while a state has authority under CAA section 116 to implement more stringent standards as a matter of state law, there is no authority under CAA section 111 or 116 for EPA to federalize such state programs.

Commenter (0808-API) presents a detailed summary of the EPA's legal analysis on this topic in the November 2021 proposal and on the contradictory analysis EPA presented during the Affordable Clean Energy (ACE) rulemaking in 2019. Commenter then provided the following analysis of the *Union Electric Co. v. EPA*, 427 U.S. 246 (1976) decision (*Union Electric*) to which the EPA referred both in the 2019 ACE rulemaking and in the November 2021 proposal:

That case involved a 1972 Missouri state implementation plan ("SIP") for sulfur dioxide. *Union Electric Co. v. EPA*, 427 U.S. 246, 252 (1976). A local utility filed

a challenge to that SIP claiming that the SIP was invalid because it imposed technologically and economically infeasible emissions control requirements. *Id.* at 253.

The court upheld the SIP on the grounds that “Congress intended claims of economic and technological infeasibility to be wholly foreign to the Administrator’s consideration of a state implementation plan.” *Id.* at 256. More specifically, the court interpreted “the ‘as may be necessary’ requirement of § 110(a)(2)(B) to demand only that the implementation plan submitted by the State meet the ‘minimum conditions’ of the [1970 CAA] Amendments.” *Id.* at 264. “Beyond that, if a State makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it – or lose a certain industry if attainment is not possible – such a determination is fully consistent with the structure and purpose of the Amendments, and § 110(a)(2)(B) provides no basis for the EPA Administrator to object to the determination on the ground of infeasibility.” *Id.* at 265.

Thus, the court expressly held (as EPA observed in 2019) that CAA § 110(a)(2)(B) allows states to adopt more stringent programs than minimally required by the Act. In that context, its observation that CAA § 116 should not be read as only authorizing more stringent state-only emissions control programs, *id.* at 264, is limited to programs such as CAA § 110 that, in the first instance, allow states to adopt more stringent measures than minimally required under the Act.

Here, CAA § 111(d) unambiguously requires state existing source programs to prescribe “a standard of performance,” which is defined to mean “a standard for emissions of air pollutants which reflects the degree of emissions limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” CAA §§ 111(d)(1)(A) and 111(a)(1). There is no room for states to do anything more than prescribe standards of performance that reflect BSER. Thus, in sharp contrast to CAA § 110, CAA § 111(d) does not prescribe “minimum conditions” that may be exceeded by the states. Instead, CAA § 111(d) requires standards of performance that must reflect a BSER determination that is based, among other things, on consideration of costs and feasibility. If proposed state standards of performance do not meet these requirements, they must be rejected by EPA.

Therefore, “structural similarities” between CAA §§ 110 and 111 do not provide an adequate basis for EPA’s proposal that it may approve state standards of performance that are more stringent than required by CAA § 111(d). Such an approach unreasonably and unlawfully ignores the significant substantive differences between CAA §§ 110 and 111 and would violate the unambiguous requirement that state § 111(d) standards of performance must reflect BSER.

To be clear, API supports the coordination and consolidation of federal and state emissions control requirements for the oil and gas sector. Ideally, only one set of standards would apply – state devised and administered emissions control programs that simultaneously satisfy CAA § 111 requirements and address any unique state priorities and objectives. We believe there is sufficient latitude under CAA § 111(d) to allow for EPA approval of state programs in most cases because, in our experience, state programs are typically grounded in principles that would satisfy CAA § 111 standard setting criteria.

But it is at least theoretically possible that a state would seek to impose emissions control obligations that go so far beyond CAA § 111 principles that such obligations cannot be squared with the federal CAA requirements. In such cases, states have authority under CAA § 116 to implement their programs as a matter of state law. But there is no authority under CAA § 111 or 116 for EPA to federalize such state programs.

Commenter (0938-TXOGA) is concerned that EPA’s statements regarding approval and federal enforceability of standards more stringent than BSER could be construed to suggest that a state could simply establish an unachievable standard based on an undemonstrated control approach and that EPA would approve such a standard into a state plan without regard to the statutory considerations in CAA section 111, which commenter asserts is plainly not a permissible outcome under the statutory language. The commenter states that while a state agency may be free under CAA section 116 to make that assessment and to enforce its view under state law (to the extent such a rulemaking would be consistent with applicable state laws), it would not be free to transform such regulations into federal law.

Commenter (0938-TXOGA) states that the position EPA expressed in the preamble appears not to consider that, unlike the SIP approval criteria in CAA section 110, cost and feasibility considerations are fundamental to the standard-setting process under CAA section 111. According to the commenter, taken to its extreme, under the rationale in the preamble, EPA could approve as federal law a state plan that sets all emission standards at zero, even if there is no technology that can achieve that level of emission, and the consequence of that would be not only that EPA could enforce this standard, which all would agree it could not have promulgated under CAA section 111(b), but also citizens would be able to enforce the standard under CAA section 304. Commenter believes that if Congress had intended this result, which would be transformative, it clearly would have spoken directly to the question.

Response I-19-14: See section XIII.C.2 (State flexibilities) of the final rule preamble for a discussion on the flexibilities afforded states when establishing standards under their state plan. See also discussion in section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble. See also the final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023.

Comment: Commenter (1267/1268/1269-CA AG et al) summarizes the rationale in the November 2021 proposal’s discussion of *Union Electric* and CAA sections 111(d) and 110 and

agrees with EPA’s view of these statutory sections and its conclusion that EPA must approve a more stringent state plan that meets the criteria set forth in the emissions guidelines. Commenter also states that such an interpretation also promotes section 111’s focus on emissions “performance,” not on whether states have adopted identical methods set forth in EPA’s guidelines.

Response I-19-15: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

## **19.4 Development of Section 111(d) State Plans**

### ***19.4.1 General Comments on State Plan Development***

Comment: Commenter (0722-MODNR) states that many states, including Missouri, lack comprehensive GHG emission tracking and reporting requirements and systems, and that this lack of data will hinder many states’ ability to develop adequate state plans pursuant to the EG. The commenter asserts that EPA should be mindful of this and provide a clearinghouse of data they have available at the federal level so that states will be in a better position to identify and engage with all the sources that must be regulated in the state plans they must develop.

Response I-19-16: States may find the following resources helpful to identify and engage with sources. EPA maintains the Greenhouse Gas Reporting Program (GHGRP) releases reported greenhouse gas emissions data annually. The most recent reporting year that is publicly available is 2022 data. GHGRP also produces resources like tools, profiles, fact sheets, and more on specific topics of interest to help the public use and derive value from the greenhouse gas reporting data. EPA also develops an annual report, called the Inventory of U.S. Greenhouse Gas Emissions and Sinks, that tracks U.S. greenhouse gas emissions and sinks by source, economic sector, and greenhouse gas going back to 1990. EPA also suggest that state review the final RIA associated with this final rulemaking.

See discussion in section V.B.5 of the December 2022 Supplemental Proposal preamble<sup>14</sup> and see discussion in section XIII.C.5 of the final preamble.

Comment: Commenters (0820-PNR, 0831-AXPC, 0922-NAM) urge EPA to provide flexibility to states in developing their plans that establish standards of performance for existing sources.

Commenters (0820-PNR, 0831-AXPC) contend that this is in keeping with the text and structure of CAA section 111, as well as with the common-sense observation that it is easier for regulated companies to plan and execute design and operational changes for new and modified sources

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<sup>14</sup> 87 FR 74827.

than for existing sources. The commenters state that the existing-source program is a cooperative federalism program under which Congress intended that states would have considerably flexibility in establishing standards of performance for existing sources. The commenters assert that the supplemental proposal and final rule should reflect this by (1) allowing states to establish less stringent or no standards on sources with a short remaining useful life, (2) allowing states to submit any existing regulatory programs they may already have adopted with no or little alteration where those programs would appropriately serve the purposes of the CAA and comport with the framework established in this federal rulemaking, and (3) allowing states to provide their existing sources with broad latitude in choice of monitoring and other compliance measures.

Commenter (0922-NAM) suggests that EPA provide guidance to the states on how to set standards of performance for methane emissions from existing sources but should also ensure the states have ample flexibility in determining those standards and give sources maximum flexibility in achieving them. The commenter notes that while authority to set the specific performance standards that would satisfy BSER at sources must remain with the states, EPA should also consider including in any final rule sufficient guidance to provide states a path to implement a “presumptively approvable” performance standards, which could set out a process for the states to use to set source-specific performance standards based on demonstrated technology. The commenter recommends that EPA be clear that such an approach is not mandatory, but it would offer an option to the states that could streamline efforts to comply with BSER, expedite EPA’s review of state plans, and thereby facilitate regulatory certainty. The commenter cautions that EPA should avoid overly restrictive approaches that simply specify a prescriptive list of technological improvements that qualify toward the achievement of BSER and then require states to adopt a subset of them, which could unduly complicate the development of state performance standards and overly limit the latitude toward developing performance standards granted to the states.

Commenter (0722-MODNR) suggests that EPA make clear in the final EG that states have the ability to make necessary adjustments on a case-by-case basis that may allow for less stringent requirements in cases where states can justify that it would be significantly more reasonable to do so. According to the commenter, such considerations could include unusual circumstances that lead to significantly higher costs and remaining useful life for identified sources among others. For additional comments on “remaining useful life and other factors”, see section 9.4.2 of this Chapter.

Response I-19-17: See discussions in sections V.B.2.,<sup>15</sup> section V.B.3.,<sup>16</sup> and section IV.B.<sup>17</sup> of the December 2022 Supplemental Proposal preamble and the requirements for meaningful engagement included in the Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023. With regard to guidance for states developing plans, including presumptive standards and state flexibilities, see section XIII.C of the final rule preamble.

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<sup>15</sup> 87 FR 74812.

<sup>16</sup> 87 FR 74816.

<sup>17</sup> 87 FR 74740.

#### ***19.4.2 “Remaining Useful Life and Other Factors” (RULOF)***

Comment: Commenters (0814-IPAA, 0820-Pioneer, 0824-WDEQ, 0831-AXPC, 0922-NAM) note that CAA section 111(d) requires EPA to allow states to take into consideration the remaining useful life of the existing source and other factors in establishing standards of performance for individual designated sources. Commenter (0922-NAM) recommends that any future rules clearly reaffirm that the states have discretion to consider multiple factors when setting the standard appropriate for a particular source or class of sources because the CAA’s text mandates that states be permitted to consider a range of source-specific variables in setting those standards and the current existing source implementing regulations reflect that authority as inherent in the states. Where EPA “has determined that a designated pollutant may cause or contribute to endangerment of public welfare,” but has not made a conclusion regarding public health effects, states may weigh “other factors of public concern” in setting emission standards. Where EPA “has determined that a designated pollutant may cause or contribute to endangerment of public health,” the implementing regulations provide that state “emission standards...be no less.”

Commenters (0820-Pioneer, 0831-AXPC) state that the existing-source program is a "cooperative federalism" program under which Congress intended that states would have considerably flexibility in establishing standards of performance for existing sources. The commenters request that the EPA's supplemental proposal and final rule reflect this by providing for states with latitude in the standards they establish for their existing sources, to include: allowing states to establish less stringent or no standards on sources with a short remaining useful life; allowing for states to submit any existing regulatory programs they may already have adopted with no or little alteration where those programs would appropriately serve the purposes of the CAA and comport with the framework established in this federal rulemaking; and allowing states to provide their existing sources with broad latitude in choice of monitoring and other compliance measures.

Commenter (0824-WDEQ) has concerns regarding the infeasible cost of control to achieve a certain standard for stripper wells and other small operators that will likely result in ceasing operations, job losses, and lost state and federal revenue. The commenter asserts that EPA’s declaration that “it would likely be difficult for states to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities” (citing 86 FR 63251) is discouraging and inaccurate. The commenter emphasizes that there are very justifiable and legitimate circumstances, such as site-specific variables, under which a different or lower performance standard should be allowed.

Commenter (0814-IPAA) expresses concern that although EPA acknowledges the right of states to take RULOF into consideration, EPA has prejudged the outcome based on the statement from EPA quoted in the previous paragraph. The commenter believes that this inherent bias before EPA even proposes revisions to the CAA section 111(d) regulation suggests a stacked deck against the rights of states to make decisions that reflect the diverse operations in their jurisdictions.

Response I-19-18: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>18</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and it's corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0855-EDF) states that EPA must ensure that any state plans submitted are rigorous and that safeguards are in place to ensure those performance standards do not fall short of EPA's guidelines. The commenter asserts that the language, structure, and history of the CAA make abundantly clear that EPA must set binding emission reduction requirements in its existing source guidelines, and that state plans may allow less effective emission standards only where a particular affected source with unique circumstances can demonstrate to the state, and the state can demonstrate to EPA, that need for a case-specific variance. After discussing the difference in EPA and state standard-setting responsibilities between CAA section 111(b) NSPS and CAA section 111(d) EG, the commenter states that under the statute, it is EPA's responsibility to specify the minimum degree of emission limitation to be incorporated in standards of performance, noting that section 111(a)(1) requires "the Administrator" to determine both the "best system of emission reduction" and the "achievable" "degree of emission limitation" therefrom. The commenter believes that this federal minimum emission limitation provides states and EPA with the substantive criteria for determining whether a state plan is "satisfactory." The commenter notes that state-issued standards of performance, in turn, translate EPA's technical determination of what pollution reductions are "achievable" into an enforceable emission limit that regulated sources cannot exceed, and EPA's regulations provide that a "standard of performance" must include "a legally enforceable regulation setting forth an allowable rate or limit of emissions into the atmosphere, or prescribing a design, equipment, work practice, or operational standard, or combination thereof" (citing 40 CFR 60.21a(f)). The commenter adds that EPA's implementing regulations for CAA section 111 have consistently recognized the agency's obligation to establish the minimum stringency level for state-issued standards of performance. The commenter notes that the regulations define "emission guideline" in terms that mirror CAA section 111(a)(1): as an emission limit reflecting the degree of emission limitation achievable through the EPA-determined "best system" and that, in turn, standards of performance in a satisfactory state plan must be "no less stringent than the corresponding emission guideline(s)" (citing 40 CFR 60.24a(c)).

Commenter (0844/0845-EDF) states that these implementing regulations directly reflect the text of CAA section 111, which commands EPA to establish a procedure under section 111 that is similar to the SIP process required under CAA section 110 wherein states adopt implementation plans to achieve and maintain the NAAQS, which EPA must then either approve or reject (in whole or in part) based on whether they satisfy the federal NAAQS. The commenter asserts that if EPA's EG did not provide clear and binding requirements to which state plans must adhere, there would be no manageable standards either for EPA to determine whether a state plan was satisfactory or for courts to review EPA's approval or denial of such plans.

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<sup>18</sup> 87 FR 74816.

Response I-19-19: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>19</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and it's corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0845-EDF) discusses the flexibility included in CAA section 111(d) and the implementing regulations, stating that EPA can approve a state plan with a package of performance standards that differ from the emission limits specified in the EG if the agency determines that the state's standards will produce at least as much emission reduction as a plan whose standards conformed to those emission limits. The commenter notes that the statute allows a state to "take into consideration" a source's "remaining useful life" and "other factors" when "applying" a standard of performance to a "particular source" (citing CAA section 111(d)(1)). The commenter asserts that the state must include any such variances in its plan and demonstrate to EPA that those specific characteristics are present.

Commenter (0844/0845-EDF) asserts that CAA section 111(d) does not permit or require a state to grant, or EPA to approve, variances for all sources merely because they have a short remaining useful life, nor does it provide that the state and EPA must tailor each source's emission reduction obligations to reflect its remaining useful life. Rather, according to the commenter, sources are entitled to have states "consider" their arguments for lesser requirements based on remaining useful life or other factors, but states (and EPA) have the discretion to find those arguments unpersuasive. The commenter contends that this is clear in EPA's implementing regulations, which permit a state to set a different standard for a specific source only if the state "demonstrates" a need based on "plant age, location, or basic process design," "[p]hysical impossibility of installing necessary control equipment," or "[o]ther factors specific to the facility...that make application of a less stringent standard...significantly more reasonable" (citing 40 CFR 60.24a(e)). The commenter adds that EPA must approve any such demonstration of need before approving a state plan as "satisfactory." The commenter concludes from this that the mere fact that an affected source may be of advanced age, or have unusual characteristics, does not in and of itself permit a state to grant a variance or require EPA to approve any such variance; rather, the source must show some specific reason why those characteristics would justify a more lenient standard.

Commenter (0844/0845-EDF) agrees with EPA's November 2021 proposal preamble discussion at 86 FR 63251 that concluded that existing sources—even units with a short remaining useful life—are unlikely to be able to show sufficient reasons justifying a variance from otherwise applicable requirements.

Response I-19-20: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>20</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR

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<sup>19</sup> 87 FR 74816.

<sup>20</sup> 87 FR 74816.



80480, November 17, 2023 and it's corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0845-EDF) states that “remaining useful life” is a term of art used in engineering and accounting that refers to an estimate of the number of remaining years that a component in a production line is estimated to be able to function in accordance with its intended purpose before warranting replacement, and that Congress’s primary motivation for using this language in CAA section 111(d) was to avoid the problem of stranded assets, which are assets that have suffered from unanticipated or premature write-downs, devaluation or conversion to liabilities. The commenter notes that in environmental regulation, this may occur when (for example) an existing source nearing the end of its useful life becomes subject to new regulations that require the installation of expensive pollution control equipment – if the source then retires soon thereafter due on account of age, the control equipment will likely be stranded, since it will have been rendered useless before long before that equipment’s useful life has expired and its operator has fully paid off the capital it invested in the device. According to the commenter, this can be a significant issue for capital-heavy industries, but the oil and gas sector is different in several regards from many or most other industries regulated under CAA section 111 – the emitting sources themselves are much more numerous, much smaller, and, in most cases, less expensive than sources in other industries, and often rely on emission reduction practices that bear little resemblance to the kinds of expensive pollution control technologies that are often found in other industries, and oil and gas sector equipment often depreciates much more quickly than do the kinds of large-scale, capital-intensive infrastructure that exist in other industries.

Commenter (0844/0845-EDF) states that work practices for other equipment in the oil and gas industry may require operators to purchase and install new equipment, but these control methods are often much less expensive than in other industries and, in many cases, allow the operator to turn a net profit through conserved gas. As an example, the commenter notes that the leak detection and repair (LDAR) standards require very few upfront capital costs, almost none of which are tied to a specific facility; instead, an operator can simply contract with an LDAR provider who will conduct surveys across the operator’s facilities. The commenter observes that if one site shuts down, the operator experiences no loss or stranded assets, and that even in the situation where an operator decides to conduct in-house LDAR surveys and purchases monitoring equipment, that equipment would not become a stranded asset and is not tied to a particular well site because the operator could continue using the monitoring equipment at other sites or sell it and recover resale value.

As another example, the commenter (0844/0845-EDF) notes that the proposed requirements for reciprocating compressors would require operators either to replace rod packing when measured leak rate exceeds 2 standard cubic feet per minute (scfm) based on the results of annual monitoring, or to capture and route rod packing emissions to a process through a closed vent system under negative pressure. The commenter states that according to EPA, rod packing replacements would entail annual capital costs of approximately \$1,700 to \$2,300, which is orders of magnitude lower than control equipment for many other industries and, moreover, these costs can generally be recouped entirely through conserved gas within 6 to 24 months so

that EPA projects that its requirements for reciprocating compressors will have net negative costs. As a third example, the commenter notes that the 2021 November proposed standards for centrifugal compressors require operators to reduce emissions by 95 percent through use of a wet-seal degassing system, which EPA reports as having capital costs around \$33,000 per compressor—still four orders of magnitude lower than a flue gas desulfurization system—with a payback period of just one to five months. The commenter adds that it may be possible for operators to reuse such degassing systems—and potentially other pollution control equipment, like vapor recovery units—for newly installed facilities once the older facilities retire.

Commenter (0844/0845-EDF) asserts that, in determining how to apply the remaining useful life provision to the oil and gas source category, EPA should consider the following three considerations regarding the extent to which states should be permitted to grant a variance: (1) Is the cost of the new equipment so relatively negligible that variances simply should not be granted, regardless of a source's remaining useful life? (2) Do cost savings achieved through recovered gas either partially or totally offset the control equipment's cost within the source's remaining useful life window, and if so, should that mean that the stranded asset problem doesn't arise and that no variances should be granted? (3) Can the control equipment be used at another emissions source after the original emissions source retires, and if so, should that option obviate the need for a variance? As for point 1, the commenter states that it is worth noting that the NSPS OOOOa rule includes a formula for determining when a capital expenditure has occurred which appears to pertain to whether or not a source can be considered modified, but EPA should consider whether it is also appropriate for establishing a monetary threshold below which states should not be permitted variances even if a source retires before the depreciation schedule for the new control equipment has expired.

Response I-19-21: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>21</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0845-EDF) asserts that EPA must prohibit states from accounting for sources' profitability when determining whether to issue variances. According to the commenter, nothing in the CAA permits the agency to accommodate aging sources and prioritize their ability to achieve a profit, even after many years of operation, over environmental considerations. The commenter notes that for sources such as aging wells that produce only marginal amounts of oil or gas decades after being drilled, EPA must not allow these operators to be given relaxed standards simply due to low profit margins, arguing that any source that is so marginal such that (for example) spending several thousand each year for leak detect and repair monitoring would eliminate its ability to turn a profit should not be operating.

Commenter (0844/0845-EDF) also asserts that a source operator's subjective opinion about the extent of the source's remaining useful life should play no role in any determination as to

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<sup>21</sup> 87 FR 74816.

whether the source should receive a variance. According to the commenter, whether a source is “useful” from an operator’s standpoint will in virtually all cases be based on its profitability rather than its actuarial value as an engineering asset, which is what CAA section 111(d)’s provision is intended to reflect. The commenter indicates that profitability—and the factors that influence it, such as oil and gas prices, the amount of recoverable product, and other considerations—are simply irrelevant to whether a control requirement would be objectively unreasonable in a particular, limited instance or would result in stranded assets. Rather than relying on operators’ own estimations of the remaining useful life of their equipment, the commenter recommends that EPA refer to Internal Revenue Service (IRS) depreciation schedules to establish clear and objective lifetimes for each type of equipment, and should also define a reasonable—and reasonably limited—number of years left on a source’s actuarial lifetime during which it can claim a variance based on remaining useful life, and even in those cases, the source should only be granted a variance if it can demonstrate particular hardship that would result from compliance based on the short window; again, marginal profitability should play no role in this determination.

Commenter (0844-EDF) states that once a source’s IRS-defined depreciation period has expired, it should no longer be permitted to qualify for a variance based on remaining useful life. The commenter indicates that operating equipment past the point in which the federal government considers it useful is poor engineering practice and often results in inefficient operation and, frequently, excess emissions. The commenter contends that to allow operators to benefit from a variance under such circumstances would not only reward the worst performers, it would incentivize operators to continue using old and failing equipment for as long as possible rather than invest in newer and more efficient infrastructure that would have no option for a variance. The commenter notes that this would defeat the entire purpose of CAA section 111(d) controls for existing sources.

Response I-19-22: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>22</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and it’s corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0845-EDF) states that where a source does qualify for a variance based on its remaining useful life, EPA must require that the source agree to a federally enforceable retirement date that reflects the expiration of the unit’s IRS depreciation schedule. The commenter notes that EPA’s 2019 ACE rule for existing fossil fuel-fired power plants, which the commenter believes took an inappropriately expansive view of CAA section 111(d)’s variance provision and which many commenters vigorously objected to and challenged in court, included a requirement that any source benefitting from the remaining useful life provision “specify the exact date by which the source’s remaining useful life will be zero” and that such source’s “associated retirement date will be federally enforceable upon approval by the EPA” (citing 84 FR 32558). Although the commenter strongly objects to the ACE Rule’s fundamental

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<sup>22</sup> 87 FR 74816.

interpretation of the remaining useful life provision, they believe that this feature of the rule was appropriate and therefore urges EPA to include in the final EG this same requirement that source's receiving a variance based on remaining useful life submit to a federally enforceable retirement date linked to the years remaining in the source's IRS depreciation schedule. The commenter concludes that if no years remain, it should not be eligible for such a variance.

Response I-19-23: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>23</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and it's corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844/0845-EDF) states that EPA should revise its implementing guidelines to more precisely define the "other factors" that are discussed in CAA section 111(d)(1). Quoting the existing regulations at 40 CFR 60.24a(e)(1)-(3), the commenter suggests that the regulatory text be revised to offer more specific and useful directions as to what may and may not factor into a state's decision to grant a variance to a particular source. The commenter supports EPA's intention to provide further clarification regarding RULOF and encourages EPA to set clearer parameters to govern when variances may be granted. The commenter adds that the oil and gas industry has several unique features that justify limiting the usual scope of the variance provision in certain regards, and the implementing regulations make clear that "each emission guideline may include specific provisions in addition to or that supersede requirements of this subpart" (citing 40 CFR 60.20a(a)(1)).

Thus, commenter (0844/0845-EDF) asserts, in the context of the EG rulemaking in particular, EPA should identify a specific and more limited set of circumstances in which states may issue variances under this provision:

1. As discussed in a previous comment, EPA should define narrow and well-defined circumstances in which the likelihood of stranded assets might permit variances, incorporating a capital expenditure threshold, an operator's ability to defray compliance costs through sale of conserved gas, and the operator's ability to use control equipment at new sources after an old source retires.
2. The EPA should also retain the existing regulation's reasonable limitation regarding physical impossibility.
3. NSPS OOOOa already includes a number of limited exceptions in the requirements themselves based on (for example) safety or temperature considerations. For instance, LDAR repair requirements are relaxed when such repairs cannot be made safely, and sources on the Alaskan North Slope are exempt from certain requirements. In its emission guidelines for existing sources, EPA should clarify that these exemptions are among the "other factors" states may consider when granting variances.

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<sup>23</sup> 87 FR 74816.

Response I-19-24: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>24</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0458-MDE) asserts that state plans to address EG requirements for existing sources should adhere to the most stringent standards, based on the BSER, with little room to deviate, as climate change benefits do not differentiate between a new or existing source.

Commenter (0941-350 Silicon Valley) indicates that they do not support EPA allowing state plans for existing facilities to make exceptions for the “expected or useful life” of equipment or exceptions for economic hardship for low-producing wells. The commenter states that small or low-producing wells are often large emitters of methane and that if small wells are not producing enough oil or gas to make this simple retrofit economically beneficial after a few years, then the wells should cease production and be sealed and capped. According to the commenter, this would also help reduce the number of future orphan wells. The commenter suggests that EPA set up a program to provide assistance and training for employees working at marginal wells if they lose their jobs because their company cannot meet higher performance standards and ceases production.

Response I-19-25: See final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023 and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0727-OK DEQ) requests further explanation of “remaining useful life”. The commenter notes that the EPA states it “intends to provide further clarification on the general process and requirements for accounting for remaining useful life and other factors . . .” 86 Fed. Reg. 63251. The commenter states that, if EPA plans to issue guidance or specific provisions regarding remaining useful life, whether a part of this rulemaking or in the implementing regulations, these details need to be known now, in order to successfully evaluate and plan for the impacts of the proposed rule and the BSER. The commenter urges EPA to release this information as soon as possible as it may inform future comments on EPA's proposal.

Response I-19-26: See discussion in section V.B.3. of the December 2022 Supplemental,<sup>25</sup> section XIII.C.3 of the final preamble, final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR

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<sup>24</sup> 87 FR 74816.

<sup>25</sup> 87 FR 74816.

80480, November 17, 2023 and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

### ***19.4.3 Integrating Existing State Programs with State Plans***

Comment: Commenter (0790-State AGs) states that the November 2021 proposal shows insufficient regard for the states in that the proposal does not account for existing state programs in any real way, merely noting their existence and saying that EPA “anticipates providing information on ways in which State plans can accommodate existing State programs.” The commenter opines that EPA intends to force states to essentially re-litigate the validity of their own programs in submitting their state plans (quoting 86 FR 63252 as proposing that states be required to “include a detailed explanation and analysis of how the relied upon existing State programs are at least as stringent as the requirements of the final [emission guidelines]”).

Response I-19-27: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>26</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0558-CCES) believes that it is extremely important to update state plans so that they align with the proposed EG. The commenter states that one of the most important elements of the EPA’s proposed standards is establishing the first-of-their-kind EG for states to reduce methane emissions from existing oil and natural gas facilities, noting that almost 86 percent of the projected emissions reductions and more than 83 percent of the projected climate benefits under the proposed rule are associated with regulating existing sources. The commenter points out that while some states have their own regulations for methane, these regulations vary widely in terms of emissions limits, testing frequency, and flexibility to use new leak detection and repair technologies.

Commenter (0558-CCES) states that there are different ways that can enable existing state programs to be adopted into state plans under the EG. For example, they suggest that for state programs that include less frequent leak detection and monitoring surveys, EPA can require these states to specify an emissions limit beyond which operators would need to perform more frequent leak tests. The commenter adds that state programs can also be updated to include a timeframe for fixing any detected leaks that does not exceed the period defined in the proposed EG.

Response I-19-28: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>27</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Several commenters (0579-Chevron, 0581-NACAA, 0610-Oxy, 0775-CO DPHE, 0820-PNR, 0922-NAM, 0926-Austin, 1267/1268/1269-CA AG et al, 1381-MPA) support

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<sup>26</sup> 87 FR 74812.

<sup>27</sup> 87 FR 74812.

flexibility in approval of existing state GHG regulatory programs in CAA section 111(d) state plans, and many of these commenters advocate for establishment of clear procedures for demonstrating equivalency.

Commenter (0581-NACAA) states that EPA should allow for programs with greater stringency or different, but at least equally stringent state approaches, by making a clear path for program equivalency application, demonstration, and determination. The commenter believes that where programs are less stringent in individual aspects but as or more stringent and protective overall, EPA should accommodate those tailored approaches that meet that state's needs. The commenter notes that EPA has demonstrated experience with creating a streamlined equivalency through the implementation of its NSPS OOOOa provisions since 2016. The commenter indicates that while there is widespread support from air agencies for an approach that awards federal credit for state programs designed to reduce GHG emissions from the oil and gas sector, it is important that any state-level measures credited toward federal compliance be at least as effective overall as the federal minimums at delivering emission reductions, even if specific aspects of the programs are less stringent because of local circumstances, constraints, and needs. The commenter adds that however EPA ultimately resolves these issues, the agency must be clear in its eventual guidance and offer a streamlined process for equivalency to give state and local agencies a high degree of certainty in leveraging their existing programs.

Commenter (0926-Austin) supports EPA's development of EG for states, including presumptive standards, and encourages EPA to engage with stakeholders on additional pathways for states to demonstrate that existing programs are at least as stringent as the final EG. The commenter believes that establishing a process for states to use successful existing programs and demonstrate those programs are at least as stringent as the final EG will facilitate cost effective emission reductions and avoid redundant compliance requirements. Additionally, the commenter urges EPA to look for ways to allow flexibility for states to demonstrate equivalency using advanced technologies, as they may provide more cost-effective pathways to reduce emissions. The commenter suggests that EPA might propose criteria for advanced technologies that EPA would use to determine equivalency with the EG.

Commenter (1381-MPA) states that the Montana Department of Environmental Quality already has a facilities registration program in place with regular inspections using optical gas imaging (OGI) cameras as well as enforcing LDAR. The commenter asserts that EPA should provide maximum flexibility under cooperative federalism to allow the individual states to manage the program and work with oil and gas operators on inspection technology and the related processes.

Commenter (0610-Oxy) states that EPA should avoid promulgating duplicative regulation that conflicts with state or other federal regulatory programs by providing flexibility for states to utilize their programs, which will allow operators to focus resources on implementing changes resulting in real emissions reductions and eliminate any confusion surrounding duplicative requirements.

Commenter (0775-CO DPHE) strongly encourages EPA to find that a state program for existing sources is equivalent to EPA's EG as EPA did for certain LDAR programs in NSPS OOOOa, even where the programs differ in some respects. The commenter notes that while Colorado's

program differs in some respects from the description of the EG in the preamble, the commenter believes that Colorado's program holistically achieves the same or better emissions reductions. The commenter asserts that for any final EG, it will be critical for EPA to leave flexibility in how states make this demonstration, particularly given that states cannot effectively begin this evaluation without a more specific proposal. The commenter suggests that EPA allow states to make a programmatic demonstration of equivalency, instead of having to demonstrate equivalency on a provision by provision or source type by source type basis (e.g., that a state's well unloading regulations are independently equivalent with the proposal). The commenter adds that states like Colorado have put considerable effort into developing the implementation structures necessary to ensure that their regulatory requirements achieve the expected emission reductions and requiring states to modify their programs based on a narrow conception of equivalency will undermine implementation processes and practices that have been developed over many years and can lead to less effective regulation.

Commenter (0775-CO DPHE) requests that EPA simplify and streamline the plan demonstration and review process for an initial CAA section 111(d) plan, as well as for any future revisions to the state program. The commenter notes that CAA section 111(d) plans are not SIPs and are therefore not subject to the same requirements and limitations. The commenter requests that EPA ensure that alternative approaches are approvable into state SIPs and section 111(d) plans. The commenter asserts that flexibility in the development, demonstration, and review of CAA section 111(d) plans for this industry is critical for effective regulation as technological innovation moves at a more rapid pace than regulatory development.

Commenter (1267-CA) recommends that EPA provide a streamlined demonstration of equivalency if the state rules already require meaningful, cost-effective GHG and VOC emission reductions. As an example, the commenter notes that New Mexico just completed a multi-year comprehensive rulemaking process and has proposed a nation-leading regulation covering both new and existing oil and natural gas sources.

Response I-19-29: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>28</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0775-CO DPHE) states that EPA should offer clarity into which components of a state's regulatory program can, or must, be included in a state's CAA section 111(d) plan. The commenter indicates that Colorado will undertake an evaluation of the efficacy of its program as compared to the proposals and will evaluate whether any additional rulemakings are necessary to prepare a CAA section 111(d) plan consistent with the CAA. Commenter notes that if Colorado can determine that its program is—or should be found—equivalent, Colorado would anticipate submitting a certification of equivalency along with a demonstration to EPA, which would identify which regulations (and other regulatory components, such as general permits or guidance documents) constitute Colorado's section 111(d) plan.

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<sup>28</sup> 87 FR 74812.



Response I-19-30: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>29</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0581-NACAA) indicates that states that have rules or well-developed proposals have already gone through robust public processes and rulemakings. The commenter states that inasmuch as the forthcoming implementation rule proposal seeks to accommodate state programs, it should consider regulatory actions and timelines required in those states and integrate flexibility into the rule that accommodates them.

Similarly, commenter (0579-Chevron) notes that many state agencies have already implemented regulations to reduce emissions from the same source categories that EPA is proposing to regulate in this rule. The commenter encourages EPA to recognize the structure and independence of state agencies to ensure consistency in requirements from different regulators, which will improve the effective allocation of resources on the part of all stakeholders.

Response I-19-31: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>30</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0935-COGA) asserts that Colorado’s existing regulations achieve equivalent or greater emission reductions than the proposed EG’s presumptive standards of performance, noting that many of the presumptive standards are based on Colorado Air Quality Control Commission (AQCC) rules, and that the November 2021 proposal preamble compares the proposed standards to Colorado’s regulations approximately 30 times. The commenter acknowledges that there are minor differences between the provisions of AQCC Regulation 7 and the draft presumptive standards, but states that such differences are allowable and do not prevent approval of a state plan. The commenter cites a decision by the federal D.C. Circuit (*Am. Lung Ass’n v. EPA*, 985 F.3d 914, 942-943; D.C. Circuit 2021) which states:

That the standards must ‘reflect’ the emission guidelines does not mean that they must embody the methods EPA contemplated in identifying the best system; rather, the States have flexibility in determining the specifics of the standards they issue so long as they accomplish the ‘degree of emission limitation’ the EPA calculated based on its ‘best system.’

Commenter (0935-COGA) asserts that Colorado’s Regulation 7 is more stringent than the draft presumptive standards in many respects, and that the Colorado rules achieve sufficient emission reductions to overcome any circumstances where the presumptive standards of performance may be more stringent than Regulation 7. The commenter concludes that Colorado Regulation 7 therefore meets or exceeds, without further rule revisions, the minimum requirements for a state plan establishing standards of performance under CAA section 111(d).

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<sup>29</sup> 87 FR 74812.

<sup>30</sup> 87 FR 74812.

Response I-19-32: See discussion in section V.B.2 (Leveraging State Programs) of the December 2022 Supplemental Proposal preamble,<sup>31</sup> and section XIII.C.2 (State flexibilities) of the final rule preamble.

Comment: Commenter (0775-CO DPHE) requests that EPA allow states to modify their CAA section 111(d) plans without needing to submit each plan revision to EPA for approval, as is required for SIP revisions. The commenter points out that under 40 CFR 60.23(a)(2), states must submit to EPA their initial CAA section 111(d) plans and any plan revisions necessary to address a final revised guideline issued by EPA, but the regulation is silent as to changes made to a state's CAA section 111(d) plan other than those relating to a revised EG from EPA. The commenter states that Colorado will need flexibility to modify its regulations covered under its CAA section 111(d) plan without waiting on EPA approval, as it must with SIP revisions. At a minimum, the commenter suggests that EPA allow states to modify their CAA section 111(d) plans without further EPA approval where the modifications do not result in less stringent regulatory programs, or where the changes are minor recordkeeping and reporting program adjustments. Alternatively, the commenter suggests that EPA consider an expedited review process for minor program changes that would not delay progress in regulating emissions from this industry.

Response I-19-33: Significant state plan revision includes, but is not limited to, any revision to standards of performance or to measures that provide for the implementation or enforcement of such standards. See the final Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (1267/1268/1269-CA AG et al) encourages EPA to create a technology hub that allows states to review and approve alternative and innovative technologies and methodologies, for states whose programs are deemed equivalent to the requirements of the EG more quickly.

Response I-19-34: See discussion in section V.C. of the December 2022 Supplemental,<sup>32</sup> section XIII of the final rule, and Response I-19-11 earlier in this chapter.

#### ***19.4.4 Compliance Measures in State Plans***

Comment: Commenters (0820-PNR, 0831-AXPC, 0922-NAM) urge EPA to confirm in the final rule that states may include a wide range of compliance measures. Specific examples are provided in the following paragraphs.

Noting that CAA section 111(d)(1) leaves implementation and enforcement of the standards to the states, commenter (0922-NAM) indicates that states can rely on state law in addition to the CAA and can use alternative means to achieve the same level of emissions reduction. The

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<sup>31</sup> 87 FR 74812.

<sup>32</sup> 87 FR 74830.

commenter points out that CAA section 111(d) incorporates certain elements of CAA section 110; for example, section 111(d) states that the “procedure” under which states submit plans establishing performance standards for existing sources should be “similar to that provided by” section 110. According to the commenter, CAA section 110(a)(2) provides that SIPs should include “other control measures,” including “economic incentives such as fees, marketable permits, and auctions of emissions rights” and allows SIPs to use these types of techniques “to meet the applicable requirements of this chapter,” which include CAA section 111(d). The commenter adds that this includes the ability to interact with other states’ programs and sources to accomplish the reductions described by the performance standards. The commenter states that any final rule should make clear that states should give sources substantial flexibility in establishing compliance measures in their state plans.

Commenter (0922-NAM) indicates that one way to reduce regulatory costs and burdens is for EPA to make it clear that a state can have a plan where there is cost sharing of emissions detection (whether drones, satellite imagery, software, or other sensors usage) by sources. The commenter asserts that any rule should explicitly recognize the states’ responsibility to adopt flexible compliance mechanisms and encourage states to ensure existing sources have the flexibility to adopt other approaches to comply with the final emission guidelines and standards.

Response I-19-35: See discussions on advanced methane detection work practices in sections X.B (Advanced Methane Detection Technology Work Practices) and XI.B (Advanced Methane Detection Technology Work Practices) of the final rule preamble.

Comment: Commenter (1267/1268/1269-CA AG et al) urges EPA to authorize the use of next generation monitoring tools to determine compliance with the requirements of the November 2021 proposal. The commenter notes that there are several innovative compliance approaches that can be used to monitor sources effectively and efficiently for compliance, while balancing the already strained resources of state agencies, and asserts that EPA should consider allowing technologies that provide quantifiable, verifiable, and consistent monitoring and compliance data at a scale that can accommodate large remote regional areas consisting of hundreds or even thousands of facilities. The commenter supports the use of remote sensing technologies at well pads, and notes that innovative remote sensing technologies for monitoring fugitive and large emission events could include aerial, truck-based, satellite, and continuous monitoring. The commenter supports these innovative approaches and points out that states like New Mexico have provided such a mechanism for their use in its proposed regulations. The commenter asserts that alternative monitoring strategies must be effective, enforceable, and equivalent, and will be a critical option for ensuring that emission leaks are identified and repaired as required.

Response I-19-36: See discussions on advanced methane detection work practices in sections X.B (Advanced Methane Detection Technology Work Practices) and XI.B (Advanced Methane Detection Technology Work Practices) of the final rule preamble.

Comment: Commenter (1267/1268/1269-CA AG et al) provides the measures that two states, California, and Pennsylvania, use to enforce their existing regulations for oil and gas facilities:

California's regulations require that operators submit reports annually containing information on LDAR inspections, tank emissions, compressor emission rates, pneumatic device emission rates, liquids unloading vented gas volumes, well casing vent emission rates, and data from underground natural gas storage ambient monitoring. Operators are also required to update their equipment inventories each year if any equipment is added or removed. CARB then uses the reported data to verify compliance, evaluate implementation of the regulation, and estimate emission reductions.

In Pennsylvania, general permits set forth standardized terms and conditions related to best available technology, compliance certification, notification, recordkeeping, reporting, and source testing requirements. While the terms and conditions of the general permits applicable to oil and natural gas operations incorporate both federal and state requirements, it is the duty of the responsible official to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations. The responsible official must sign and submit a certification of compliance with the annual report. The annual report serves as the basis for the compliance certification. Any records generated as part of the terms and conditions of the general permits are required to be maintained on site or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format. The key records generated and maintained by the owner or operator of a facility authorized under the general permit are those that show the facility is in compliance with the facility-wide emission limits on a 12-month rolling basis. All records, reports, or other information obtained by the Pennsylvania Department of Environmental Protection under the general permit are publicly available unless the owner or operator of the facility shows cause that the information is confidential. Under no circumstance are records of emission data eligible for confidentiality.

Response I-19-37: EPA acknowledges the information provided by the commenter.

#### ***19.4.5 Comments on Emissions Inventories in State Plans***

Comment: Commenters (0424-WVDEP, 0580-KDAQ, 0727-OK DEQ, 0775/0776-CO DPHE, 0824-WDEQ, 0832-NMED, 1267/1268/1269-CA AG et al) agree with the EPA that it is not practical to require states to compile emissions inventories in the same way that is typically expected for other industries under other EG and support superseding the requirements of 40 CFR 60.25a(a) for the purposes of the EG.

Commenter (0424-WVDEP) is concerned with the resources it would take to develop a source-specific or unit-specific inventory of all designated facilities, including emission rate data for the designated pollutants correlated with applicable standards of performance for the oil and gas industry and with the annual progress reports. The commenter notes that in addition to the vast number of sources and the frequent change of configurations and ownership within this industry, the BSER as proposed does not take the form of an emission rate and would complicate the correlated demonstration as required under 40 CFR 60.25a.

Commenter (0824-WDEQ) favors this approach and emphasizes that they believe this is the only viable pathway for state agencies like Wyoming's with limited staff resources for compiling emission inventories. The commenter states that there is no achievable approach for commenter's agency to submit source-specific or unit-specific data for a proposed rulemaking that expands the scope of affected facilities on such a massive scale. The commenter agrees with EPA's approach that "allows States to utilize existing inventories and emissions data" (citing 86 FR 63253) and requests that EPA further clarify this approach.

Commenter (0832-NMED) agrees with the EPA that a highly detailed GHG emissions inventory is not necessary for states to develop standards of performance, and that such standards of performance could be developed using a different type of emissions inventory data. Accordingly, the commenter supports the proposal to allow states flexibility to utilize existing inventories and emissions data to develop their state plans as they pertain to EG OOOOc.

Commenter (1267/1268/1269-CA AG et al) states that EPA should allow states to utilize existing inventories and emissions data, even if that data might not fully align with the designated facilities in the EG and may exclude some facilities that are subject to the EG. The commenter notes that allowing states to leverage existing data would obviate the need to duplicate work developing emissions inventories, if the data submitted by states is rigorous and comprehensive enough to accurately capture emissions from the oil and natural gas industry.

Commenter (0775/0776-CO DPHE) notes that based on 2020 leak inspection reporting, Colorado's best estimate is that there are over 15,000 well production facilities in the state. The commenter believes that there is little benefit, and great burden, to having to specifically identify each such facility, less yet every single natural gas-driven pneumatic controller, in the section 111(d) plan and any revisions. The commenter points out (citing 86 FR 63253) that EPA has solicited comments on the practicability of states compiling an inventory of all designated facilities and may require state emission inventories to determine equivalency, and that EPA appears to also be considering accepting its Greenhouse Gas Reporting Program (GHGRP) as a proxy. The commenter asserts that Colorado already has a robust annual emissions reporting program for upstream and midstream (gathering, boosting, and processing) sources, and should be permitted to rely upon its comprehensive system both for identification of sources and for a demonstration of equivalency.

Response I-19-38: See discussions in section V.B.5 (Emissions Inventories) of the December 2022 Supplemental<sup>33</sup> and section XIII.C.5 (Emissions inventories) of the final preamble.

Comment: Commenter (0727-OK DEQ) recommends that, in superseding the requirements of 40 C.F.R. 60.25a(a), they provide the following suggestions on how EPA should accomplish this goal:

(1) EPA should simplify the requirement to identify designated facilities potentially subject to the EG, taking into consideration the large number of such facilities and

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<sup>33</sup> 87 FR 74827.

(2) EPA should accept emissions data for these facilities in accordance with the provisions of the Air Emissions Reporting Requirements (AERR), with detailed requirements for designated facilities that are classified as AERR Type A and B sources and the use of alternative methods (e.g., a nonpoint tool) for designated facilities that would be classified as nonpoint sources under the AERR.

Notably, the commenter (0727-OK DEQ et al) states that 40 C.F.R. 60.25a contains outdated language, especially in reference to Appendix D, which predates the AERR and even predates AERR's predecessor, the Consolidated Emissions Reporting Requirements (CERR). Appendix D was last updated in 1975, and it appears the National Emissions Data System (NEDS), as referenced in Appendix D, was last updated in 1980, although it is difficult to find a historical timeline of its use. The CERR was finalized in 2002, and the AERR was finalized in 2008. The commenter notes that inventories have not been collected in the manner 40 C.F.R. 60.25a dictates for quite some time. The commenter suggests that EPA update the rules to reference 40 C.F.R. 51a, i.e., the AERR. Furthermore, the commenter adds that AERR already has emissions thresholds for what should be inventoried as a point source, and what is being captured in the National Emissions Inventory (NEI) as a nonpoint source. The commenter believes the rule should align with the AERR thresholds and requirements.

Response I-19-39: See discussions in section V.B.5 (Emissions Inventories) of the December 2022 Supplemental Proposal<sup>34</sup> and section XIII.C.5 (Emissions inventories) of the final rule preamble.

Comment: While agreeing with the EPA that it is not practical to require states to compile emissions inventories in the same way that is typically expected for other industries under other EG, commenter (0832-NMED) does not agree that the GHGRP data should be used. The commenter notes that the reporting threshold of 25,000 metric tons under the GHGRP would exclude the emissions from thousands of smaller upstream oil and gas facilities, which in the aggregate represent a significant amount of GHG and criteria pollutant emissions. The commenter supports allowing states to use other available existing inventory information, so long as the inventory adequately captures data, or estimates emissions, from all potential designated facilities.

Similarly, commenter (0727-OK DEQ/OSEE) does not support leveraging the GHGRP for purposes of the EG because (1) the GHGRP would not reflect emissions from smaller operators and (2) the GHGRP has default emission factors and default equipment counts built in that do not necessarily reflect actual data on site. The commenter believes that the National Emissions Inventory (NEI) does a better job of quantifying emissions from all sources.

Response I-19-40: See discussions in section V.B.5 (Emissions Inventories) of the December 2022 Supplemental<sup>35</sup> and section XIII.C.5 (Emissions inventories) of the final preamble.

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<sup>34</sup> 87 FR 74827.

<sup>35</sup> 87 FR 74827.

#### ***19.4.6 Meaningful Engagement***

Comment: Commenters (0391-KBIC, 0605-Muscogee, 0781-NTAA, 0833-UMUTE PD, 0943-SSMTCI) support requiring states to include community engagement as part of the program approval for State Plans for existing sources. Commenters (0391-KBIC, 0781-NTAA, 0833-UMUTE PD, 0943-SSMTCI) add that it is equally, if not more important to include consultation and coordination with neighboring Tribal Governments. The commenters assert that this will be particularly important in the checker boarded areas where jurisdiction between state, tribe, and federal agencies can be convoluted and confusing. The commenters believe that requiring consultation and coordination between all government entities will provide more consistent understanding of the requirements, implementation, and enforcement across jurisdictions.

Response I-19-41: Comment is a supportive comment on an aspect of the November 2021 Proposal that is not being finalized in this action; as such, no response is required. See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0763-TCEQ) states that EPA should clarify its authority to require “meaningful engagement” before requiring such burdensome actions by states.

Commenter (0938-TXOGA) notes that the November 2021 proposal does not identify the legal authority for this requirement beyond high-level statements that such authority is provided by CAA sections 111(d) and 301(a)(1) (citing 86 FR 63145). The commenter has concerns that these provisions do not provide the authority that EPA claims, and states that the proposal lacks sufficient detail to allow for meaningful comment on this issue. The commenter requests that this authority be further substantiated in EPA’s subsequent proposal.

Commenter (0921-USCoC) states that while they support meaningful engagement with members of the public and with members of disadvantaged communities, neither CAA section 111(d) nor section 301 provides a legal basis for EPA’s proposed actions requiring meaningful engagement. According to the commenter, EPA has not adequately explained how the CAA could allow EPA to promulgate environmental justice (EJ) requirements as part of an NSPS or EG, or how EPA could require states to provide EJ regulatory requirements as a part of a state plan. The commenter asserts that the CAA provides no authority for EPA to include EJ requirements in the EG as the model for states, and that EPA can neither compel states to include EJ requirements in state plans nor disapprove a state plan if a state fails to include EJ analysis. The commenter goes on to assert that if a state, based on its own authorities, voluntarily includes EJ requirements as part of its state plan, EPA cannot convert the EJ elements into federally enforceable requirements, and that when issuing a federal implementation plan (FIP) for states that fail to develop appropriate state plans, EPA cannot include EJ requirements, as that would exceed the scope of EPA’s CAA authority.

Commenter (0808-API) states that, while they support EPA's goals for meaningful engagement, the Agency has not provided sufficient detail in the proposal to allow the commenter to comment in a meaningful way. The commenter notes that there is no explanation of the substantive legal underpinnings other than broad statements that the requirements are authorized under CAA sections 111(d) and 301(a)(2), with no explanation of the substantive legal underpinnings of this concept.

Response I-19-42: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0790-State AGs) states that the November 2021 proposal shows insufficient regard for the states in that the proposal would regulate the way in which the states will solicit comments on potential state plans. The commenter indicates that it is not clear what new requirements for "meaningful engagement" EPA wants to impose beyond public hearings, but this apparent intrusion into the basics of the states' administrative processes would constitute troubling and unfounded federal overreach into state administration.

Response I-19-43: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0727-OK DEQ/OSEE) supports robust public participation in state rulemaking efforts and states that Oklahoma conducts public participation processes in accordance with the law. The commenter adds that states are already required to take measures to consider EJ in state activities and asserts that an additional EJ requirement within this rulemaking seems unfounded and redundant.

Response I-19-44: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenters (0828-UCS, 0832-NMED, 0844/0855-EDF) support the community participation requirements described in the proposal. Commenter (0844/0855-EDF) agrees that



“robust and meaningful public involvement in the development of a State plan should go beyond the minimum requirement to hold a public hearing,” but must instead include “ensuring that States share information with and solicit input from stakeholders at critical junctures during plan development, which helps ensure that a plan is adequately addressing the potential impacts to public health and welfare that are the core concern of CAA section 111.”

Commenter (0832-NMED) similarly states that requiring states to share information and solicit input from stakeholders at critical junctures during plan development will ensure communities have abundant opportunities to participate in the plan development process. The commenter states that the proposed reasonable notice requirement, with an additional and separate meaning from “public hearing,” will ensure the public has reasonable notice of relevant information, as well as the opportunity to participate in the state plan development. The commenter believes that requiring states to provide this opportunity to stakeholders directly addresses a major issue of environmental inequity – the ability for stakeholders to participate in the process that determines impacts and risks to their health and environment.

Commenter (0828-UCS) states that the proposal to require state plans be developed with “meaningful engagement” from members of the public, including overburdened and underserved communities, is an important stride in better incorporating EJ concerns into the rulemaking process. The commenter asserts that EPA must ensure that the final rule include strong implementation of this provision.

Response I-19-45: Comment is a supportive comment on an aspect of the November 2021 Proposal that is not being finalized in this action; as such, no response is required. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenters (0581-NACAA, 0832-NMED, 1267/1268/1269-CA AG et al) support the EPA’s proposal to require a robust and meaningful public participation process during state plan development but advise EPA to provide flexibility. One of these commenters (1267-CA) adds that because some states have developed more robust environmental justice programs than others—including with respect to public participation—EPA should take existing state practices into account.

Another of the commenters (0832-NMED) wants to ensure that the EPA will allow states the flexibility to craft these plans to the unique economic and demographic features of each state. The commenter recommends that the EPA permit both new and traditional communication technologies to qualify to conduct meaningful public engagement, adding that modern communications technology (such as video conferencing, social media, and smart phone apps) has made it much easier for states to effectively communicate with various communities and stakeholders. The commenter believes that while there may be barriers involving accessibility to these technologies that should be considered, these technologies should still be utilized during

the meaningful engagement process. The commenter states that considering recent events, it is clear that video conferencing can be an effective planning tool that allows for planners and state officials to communicate with community members and other stakeholders, which is why commenter believes these technologies should be utilized as a way to meaningfully engage with communities and stakeholders.

Commenter (0581-NACAA) suggests that where agencies have completed their own analyses and developed tools and programs in consultation with their local communities and advisory groups, EPA should allow these to serve compliance needs, rather than simply mandating national adoption of federal tools. The commenter notes that some NACAA members are at the cutting edge of achieving meaningful involvement of vulnerable communities in agency decision-making, with programs that have far longer track records and that are more robust than anything at the federal level. The commenter suggests that EPA can and should draw from and benefit from their experience. The commenter adds that allowing state and local agencies flexibility will enable meaningful interaction that yields real benefits without being simply a performative checklist. The commenter indicates that state and local programs with deep experience in advancing clean air protection with and for vulnerable communities have learned that these efforts are very time- and resource-intensive, not just for agencies but for the communities themselves. The commenter concludes that given the tremendous variety of communities, their needs, and their constraints, EPA should set expectations realistically and allow for the flexibility to truly meet the unique needs of these communities, as well as to reflect the economics and demographics of individual states.

Response I-19-46: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844-EDF) encourages EPA to require that state plans engage the public in a way that is receptive to the needs and characteristics of the affected communities and gives two examples: (1) If a state's oil and gas industry has a significant impact on a community that includes many members who primarily speak a language other than English, the state must account for that fact as it engages that community in the plan development process; and (2) If an affected community includes many individuals who lack access to broadband internet, the state must make a serious effort to conduct outreach through means other than just the internet. The commenter notes that some states already have community outreach and engagement procedures in place and suggests that EPA should survey these existing procedures in leading states and develop a model for others to follow.

Commenter (0733-CVNM) urges that the EPA require the State of New Mexico to comply with the mandates for meaningful engagement in a manner that takes the nature of the state's population into account adequately. The commenter states that presenting notice of opportunities for involvement in the preparation of the New Mexico state plan in written English and Spanish

will not reach some members of communities in northwestern New Mexico, where there is significant oil and gas activity. The commenter notes that in those communities and other Native American communities in New Mexico, many people communicate by means of languages that are not written. The commenter asserts that the EPA therefore should require that the State of New Mexico provide notice of opportunities to be involved in the preparation of the state's plan by other means, such as advertisements on television and radio and announcements in locations that are likely to reach residents such as Chapter Houses, churches, and community centers.

Response I-19-47: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Some commenters urge EPA to ensure that communities that benefit from the oil and gas industry are included in “meaningful engagement” outreach.

Commenter (0822-TXAEP) supports “robust and meaningful public engagement” with “underserved or overburdened communities” and notes the production of oil and natural gas allows communities across the U.S. to heat their homes and take advantage of affordable, abundant power for their personal and business aspirations. The commenter states that many rural communities in producing states depend on oil and natural gas production for their livelihoods and would suffer adversely if that production is lost. The commenter adds that beyond the homeowners and farmers that directly rely on gas from wells and/or pipelines, there are many communities that rely exclusively on gas supplied by marginal wells located geographically close to their homes and would not be served if low production wells are shut in.

Commenter (0814-IPAA) states that EPA has appropriately placed much of its concern about EJ on disadvantaged communities; however, it can also be an issue for those that rely on the production of oil and natural gas for their energy or for royalties that sustain their farms or ranches or local communities. The commenter believes that drawing the intricate balances on these issues will be neither straightforward nor without conflict, and that states will need clear and thorough guidance and training to undertake these tasks. The commenter adds that depending on how EPA crafts the requirements, states may need authorizing state legislation to implement them. Commenter indicates that EPA needs to fully set forth all the factors when it proposes its revisions to CAA section 111(d) regulations.

Commenter (0938-TXOGA) suggests that EPA ensure that EJ analyses consider how productive operations benefit EJ communities and how regulations may impact those benefits (e.g., economic impacts, effects on tax base for schools). The commenter states that EPA must recognize that in rural communities, the gas from these wells is important not only for comfort heating and cooking but also for their economic well-being, providing critical sources of income. According to the commenter, these benefits are important to consider in any such analysis.

Commenter (0581-NACAA) states that as EPA brings its own community support resources to bear, it should not be forgotten that some of the most affected communities will be closely tied socially and economically to the oil and gas industry. The commenter believes that resources should be targeted to help mitigate impacts to these affected communities as well. For additional comments related to environmental justice meaningful engagement considerations, see section 3.3 (EJ Outreach and Engagement) of Chapter 3 of this document.

Response I-19-48: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0844-EDF) asserts that a state should be required to engage all communities that have a stake in its plan development, including those that may live across the border in another state; if a state's economic activity has a detrimental impact on residents in another state, it is only appropriate that the state address that fact as it develops plans to reduce emissions. The commenter notes that the CAA explicitly recognizes this in other context: in developing SIPs under the national ambient air quality standards program—a program that CAA section 111(d) expressly cross-references—states must include provisions that “prohibit ... any source or other emissions activity with the State which will ... contribute significantly to nonattainment in, or interfere with maintenance by, any other State.” The commenter adds that requiring states to conduct appropriately robust outreach to affected communities in other states is a far more modest requirement than this, and EPA should include it in the final EG OOOOc rule.

Commenter (0832-NMED), responding to the request for comments and suggestions on how to coordinate emissions crossing state borders, indicates that states, local governments, community organizations, and other stakeholders may find it helpful to create organized groups that can help address interstate air quality issues. The commenter reports that they participate in the Four Corners Air Quality Group, which could serve as a model for such coordination; New Mexico, along with the Navajo Nation, Colorado, Arizona, and Utah meet regularly to address common air quality issues in the region. The commenter adds that the Four Corners Air Quality Group includes a variety of different stakeholders such as community members and organizations and industry leaders. The commenter states that the goals and functions of any cross-border groups can, and should, be crafted to the unique needs of the area(s) in which they serve, and that these organizations open a dialogue between all stakeholders and consist of government officials and staff members that can directly address any issues of concern.

Response I-19-49: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for

Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Several commenters request that EPA provide additional information on what constitutes acceptable “meaningful engagement” in state plans.

Commenter (1267-CA) supports setting forth in the final rule some minimum criteria for the meaningful engagement requirements. The commenter also states that, with respect to some of the meaningful engagement criteria that EPA has identified, it would be helpful if the agency provided some additional information in the final rule. As an example, the commenter suggests that EPA could offer thoughts on how states could go about making public meetings or workshops safe spaces for undocumented members of overburdened or underserved communities; similarly, EPA could specify that information about the rulemaking to be shared at a public meeting or workshop be translated in communities with linguistic barriers by EPA’s duties under Title VI the Civil Rights Act.

Commenter (0456-WDNR) recommends that, given the varying needs of vulnerable communities across the country, EPA should work with states to set clear and reasonable expectations and allow for the flexibility to meet the unique needs of local communities. The commenter believes that air agencies will be more efficient and effective in providing meaningful and timely engagement if EPA gives more input on what constitutes meaningful engagement with the target populations and the specific actions that could be taken during the state plan development process to meet this new requirement. The commenter adds that new funding mechanisms such as federal grants should be made available to assist implementing agencies with the new public engagement requirements.

Commenter (OK DEQ) requests that EPA clarify the term “meaningful engagement” and exactly what is required by states to fulfill this standard. The commenter believes that the breadth of the term “meaningful engagement” is unclear in the proposed rule, and without further definition could create pitfalls for states when carrying out the requirement. The commenter states that clarity is needed on exactly how states should identify these communities and then engage with them, asserting that without further guidance, the granularity of the meaningful engagement requirement is unclear and could possibly lead to absurd interpretations from third parties. While supporting support robust public participation, the commenter states that extent to which states must commit resources to additional public engagement above what is currently required by law is unclear, and states need to know the extent of said requirement to appropriately allocate their very limited resources.

Commenter (0763-TCEQ) states that the EPA should issue timely guidance to states regarding the expected procedures for states to follow in conducting and documenting meaningful engagement as part of state plan development and implementation. Noting that EPA also proposed that states may apply for, and the EPA may approve, alternate meaningful engagement procedures, the commenter also states that EPA should provide guidance on how a request for alternative procedures should be made, how it would be evaluated by the EPA, and the expected timing in the state planning process for states to make and the EPA to act on such requests.

Commenter (0445-IDEM) believes that states would benefit from further guidance on the scope of public participation in areas that EPA defines as overburdened and underserved and that EPA would expect to see in an approvable plan. The commenter notes that as many of the affected sources in Indiana are in rural areas, Indiana is particularly interested in further guidance on what “meaningful outreach and engagement” would mean with respect to rural communities.

Commenter (0445-IDEM) also notes that Indiana is statutorily restricted in its ability to promulgate rules that are more stringent than federal environmental regulations but targeting select communities with additional public involvement could create expectations from the communities that the state would require sources to comply with provisions beyond the scope of the presumptive limits provided in the federal rule. The commenter states that Indiana likely could not comply with the additional process requirements that would be needed to deviate from the presumptive federal standards and meet the federal statutory deadlines for submitting a plan to EPA. The commenter requests that since states have not previously been asked to include these steps in state plans, EPA should provide additional guidance to states on what it expects to see in an approvable plan, while providing the flexibility to tailor outreach efforts to the needs and state statutory requirements of their respective states.

Commenter (0722-MODNR) urges EPA to understand the need for regulatory certainty when it comes to requirements that will affect the approvability of state plans and states that EPA should provide a clear regulatory definition of “underserved and overburdened communities.” Commenter asserts that the regulatory text should also clearly describe what requirements states must follow with regard to engaging with these communities. The commenter believes that it would be inappropriate for EPA to address these issues and expectations solely through preamble text or non-regulatory guidance or memos, and asserts that without regulatory certainty that explains how states identify these communities and precisely what additional requirements states must meet with respect to engaging with them, it will result in inconsistency across the country and could cause other regulatory authority issues for many states. The commenter notes that this is especially true for states, like Missouri, that have statutes to prevent SIPs or state regulations from being more stringent than required by the CAA.

Commenter (0458-MDE) states that community discussion, public meetings, and email notifications of the regulation development process are good tools to implement prior to the formal regulatory adoption process.

Commenter (0938-TXOGA) states that the November 2021 proposal did not detail the standards for meaningful engagement. Commenter is concerned that this requirement could be invoked to disapprove a state plan on a subjective judgment of what engagement is “meaningful.” The commenter believes that this issue is important because states and the public expend significant resources in developing a state plan for submittal, and the consequence of disapproval is that these costly processes would need to be repeated to remedy the deficiency. The commenter asserts that it is important for any standard of “meaningful” engagement to be defined clearly ahead of the rulemaking processes that states will undertake to develop their plans.

Commenter (0581-NACAA) states that should EPA mandate more robust public engagement and make it a federal requirement for plan approval, the agency must be more specific about

what will be approvable and provide guidance to states. The commenter notes that some states have conducted robust analyses and implemented sophisticated programs, but not all agencies have done this work – EPA can help implementing agencies meet clearly articulated federal requirements by providing resources, guidance, trainings, and other support.

Commenter (0808-API) states that, while they support EPA’s goals, the Agency has not provided sufficient detail in the proposal to allow the commenter to comment in a meaningful way. The commenter notes that there is no proposed language to understand the impact of what the Agency intends to do.

Response I-19-50: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0775/0776-Air Pollution Control Division, Colorado Department of Public Health and Environment (CDPHE)) states that Colorado has taken a great many strides towards pursuing environmental justice and addressing the disproportionate impacts of air pollution on communities. CDPHE recently created an Environmental Justice Unit that seeks to strengthen community engagement by building trust and working to reduce disproportionate harm and increase environmental and health protections. The commenter provides that they have an Environmental Justice Unit that manages the state’s new Environmental Justice Action Task Force<sup>36</sup> and the Environmental Justice Advisory Board<sup>37</sup>. Starting on July 1, 2021, the commenter states that the CDPHE began implementing new legislation that directs a meaningful level of engagement with disproportionately impacted communities<sup>38</sup> when considering new regulations. The commenter states that the CDPHE’s Environmental Justice Unit, in

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<sup>36</sup> The Environmental Justice Action Task Force (“Task Force”) was created by the Colorado Environmental Justice Act to “recommend and promote strategies for incorporating environmental justice and equity into how state agencies discharge their responsibilities.” Colo. Rev. Stat. § 25-1-133(1)(a). “The mission of the Task Force is to propose recommendations to the General Assembly regarding practical means of addressing environmental justice inequities by: (a) Promoting environmental justice across state agencies and improving collaboration among state agencies in identifying and addressing the human health and environmental effects of programs, policies, practices, and activities on disproportionately impacted communities; (b) Improving cooperation on environmental justice initiatives between the state government, tribal governments, and local governments; (c) Ensuring meaningful involvement and due process in the development, implementation, and enforcement of environmental laws and policies; and (d) Addressing environmental health, pollution, and public health burdens in disproportionately impacted communities and building healthy, sustainable, and resilient communities.” Id. at -133(2).

<sup>37</sup> The Environmental Justice Advisory Board is a volunteer board with 12 members appointed by Colorado’s Governor and Executive Director of CDPHE. Colo. Rev. Stat. § 25-1-134(2). The Board serves Colorado by: Coordinating with the Environmental Justice Ombudsperson; advising CDPHE on best practices for engaging disproportionately impacted communities; responding to environmental justice policy matters referred by the Governor’s Office or CDPHE; and creating and overseeing an environmental justice grants program.

<sup>38</sup> Colo. Rev. Stat. § 24-4-109(2)(b)(II).

implementing the legislation, has found the following engagement practices to be effective at improving a two-way communication pathway with communities:

- Scheduling variable times of day and days of the week for opportunities for public input on the proposed action, including at least one weekend time, one evening time, and one morning time for public input;
- Providing notice at least thirty days before any public input opportunity or before the start of any public comment period;
- Utilizing several different methods of outreach and ways to publicize the proposed action, including disseminating information through schools, clinics, social media, social and activity clubs, local governments, tribal governments, libraries, religious organizations, civic associations, community-based environmental justice organizations, or other local services;
- Providing several methods for the public to give input, such as in-person meetings, virtual and online meetings, online comment portals or e-mail, and call-in meetings;
- Considering use of a variety of locations for public input on the proposed action, including meeting locations in urban centers, in neighborhoods whose populations are predominantly black, indigenous, or people of color and have an average income below the state's average, and in rural locations in various regions of the state; and
- Creating outreach materials concerning the proposed state action in layperson's terms, translated into the top two languages spoken in a community, that inform people of opportunities to provide input on the proposed state action, their rights, the possible outcomes, and upcoming public input process.<sup>39</sup>

Commenter (0775/0776-CDPHE) recognizes the importance of language justice in communicating with communities where English is not the only, or primary, language spoken by residents. For example, the commenter states that they seek to make plain language fact sheets about rulemaking available in both English and Spanish, given demographics and languages spoken in parts of Colorado with significant oil and gas development. As a specific example, the commenter states that, in Weld County, where 86% of Colorado's oil was produced in 2021, 17.5% of the population speaks Spanish at home.<sup>40</sup> The commenter states that CDPHE seeks to provide Spanish interpretation services during public meetings, and allows for Spanish language public comments, which can be translated into English for purposes of comment response.

Commenter (0775/0776-CDPHE) states that, as it pertains to adopting regulations designed to protect residents who live and work near oil and gas operations, CDPHE used a combined approach, incorporating stricter standards for operations in disproportionately impacted communities and, in some cases, where the operations are located within 1,000 feet of an

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<sup>39</sup> Colo. Rev. Stat. § 24-4-109.

<sup>40</sup> For Weld County percentage of oil production, source is COGCC data page, <https://cogcc.state.co.us/data4.html#/production>, select "Monthly Production by County," production year 2021, export to Xcel; in "Oil produced" category, with data through November 2021, Weld County produced 106,584,883 BBL out of 124,009,383 BBL total, which is 85.949%. For Spanish speaking data, source is U.S. Census Bureau American Community Survey (ACS) 2019 1-Year Subject Estimates, <https://data.census.gov/cedsci/table?q=United%20States&t=Language%20Spoken%20at%20Home&g=0500000US08123> (select "Weld County" for geography" and "Language Spoken at Home"); Weld County population is 301,838, with Spanish spoken at home by 52,842 residents or 17.5%.



occupied area.<sup>41</sup> In disproportionately impacted communities, the commenter notes that Regulation Number 7 now: ensures quicker and more frequent testing of combustion devices; requires more frequent leak inspections and earlier repair of leaking components; ensures quicker, and more, reductions from midstream pigging and blowdown operations; and requires control of more well liquids unloading events. The commenter reports that these rules were designed to reduce emissions in disproportionately impacted communities, and therefore reduce the local health and environmental impacts of oil and gas operations. The commenter states that CDPHE consulted with community members, community organizations, and parties representing the interests of disproportionately impacted communities in the development of these regulations.

Commenter (0775/0776-CDPHE) states that, in addition to the CDPHE actions described above, the commenter notes that during its Mission Change Rulemaking, Colorado Oil and Gas Conservation Commission (COGCC) also adopted both substantive and procedural standards for applications to site new oil and gas facilities within disproportionately impacted communities. COGCC's Mission Change rules define and map disproportionately impacted communities, require that permit applicants provide information about whether the proposed development is located in a disproportionately impacted community, and identify whether there are other existing oil and gas or other industrial impacts nearby. This will allow COGCC to evaluate the potential cumulative impacts of proposed oil and gas development on disproportionately impacted communities over time.

According to the commenter (0775/0776-CDPHE), another key substantive standard for disproportionately impacted communities is the alternative location analysis, Rule 304.b.(2),<sup>42</sup> which requires operators proposing oil and gas development near homes within a disproportionately impacted community to evaluate alternative locations, describe their community engagement work, and identify other existing nearby facilities. The commenter notes that this allows COGCC to evaluate whether there is an alternative location where a facility could be built that would result in fewer impacts, or that would more equitably distribute impacts in an area that is bearing relatively less burden from existing development.

Finally, commenter (0775/0776-CDPHE) states that COGCC also adopted several very important procedural standards for permit applications in disproportionately impacted communities. These procedural standards are designed to ensure that residents of disproportionately impacted communities have a meaningful opportunity to engage in COGCC's administrative process of reviewing and deciding whether to approve or deny an oil and gas development plan. The commenter provides that these standards include longer public comment

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<sup>41</sup> "Occupied Areas" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly." Reg. 7, Part D, Section II.A.16.

<sup>42</sup> 2 Code Colo. Regs. § 404-1:304.b.(2).

periods, longer consultation periods, and several rules requiring information to be made available in languages other than English.

Response I-19-51: See section XIII.C.6 (Meaningful engagement) discussion of the final rule preamble. See also the requirements for meaningful engagement included in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

#### ***19.4.7 Support for States to Develop, Implement and Enforce Rule***

Comment: Commenters (0456-WDNR, 0581-NACAA, 0824-WDEQ, 0832-NMED) state that EPA should provide support to states to identify designated sources and to implement and enforce the rule. Commenter (0456-WDNR) notes that considerable effort will be needed to implement and enforce this rule, especially as it affects sources that have never been subject to permitting under the CAA. The commenter indicates that even to prepare and submit a state plan, a state must first identify existing facilities within its borders that meet the applicability requirements in the final EG. The commenter believes that because the regulation of greenhouse gases under CAA sections 111(b) and 111(d) is a relatively recent development, some facilities, such as those in the natural gas distribution category (North American Industry Classification System code 221210) will be completely unfamiliar with these types of air pollution regulations and their need to comply. The commenter urges EPA to consider funding mechanisms, including federal grants, to support implementation and enforcement of this rule, especially as it affects sources currently not subject to CAA permitting or emissions reporting programs.

Commenter (0824-WDEQ) expresses concern that, if the expectation is for states to develop, implement, and enforce State plans that profoundly expand their air quality division's overall scope of work associated with these requirements, it is imperative that EPA provide states with the necessary financial resources to comply instead of providing states with an unfunded mandate. The commenter (0824-WDEQ) expresses specific concerns regarding the resource burden associated with states having to include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of standards of performance.

Commenter (0832-NMED) states that New Mexico will require considerable staffing and financial resources to implement and enforce the proposed rules and urges EPA to provide sufficient funding to states to ensure effective and consistent implementation and compliance with the requirements of the proposed rules. The commenter urges EPA to provide proportionate funding to those states with significant oil and gas activities and to fund states based on their proportion of the total national oil and gas production. The commenter notes that New Mexico's oil and gas sources contribute more than 53 percent of the state's total GHG emissions profile and rising ozone levels over significantly large and rural geographic land areas means ensuring compliance is resource intensive using traditional staff approaches, and expensive using innovative high-altitude platform stations. To that end, the commenter believes that the EPA

should consider including compliance assurance activities in federal grants, such as in the CAA section 105 grant and the Performance Partnership Grant. Because these rules will bring in thousands of new sources under the agency's regulatory jurisdiction, the commenter states that a concomitant level of resources and financial assistance is critical to ensure the rule's significant and important emission reductions are achieved. The commenter asserts that frontline communities are critically aware that many states already lack sufficient resources to effectively implement and enforce current air regulations, and that without new and sufficient resources to states to guarantee effective implementation and compliance, the emissions reductions and public health benefits contemplated from the proposed rules will not be realized, and the health of frontline communities and the environment will continue to be impacted.

Commenter (0581-NACAA) points out that state and local clean air agencies face a wide variety of circumstances and situations that will affect their ability to implement this rule if it is finalized as proposed. The commenter identifies some of these issues and offers recommendations that would affect successful implementation of the rule. In particular, state and local air agencies have seen flat federal funding support for CAA implementation for nearly two decades, and for some agencies, meeting the additional regulatory requirements proposed will require additional resources. In addition to the commenter reiterating their longstanding call for EPA to meet its obligation to support adequate funding for its state and local co-regulators, the commenter's recommendations include steps EPA can take to streamline regulatory burdens, meet varied state needs with appropriate flexibility, support state and local agency implementation capacity, and acknowledge and avoid constraints.

Response I-19-52: The EPA does intend on working with tribes and states to develop plans tailored to the factors concerning the states. The plan development process, under which performance standards for existing sources are established within their jurisdiction and have the discretion to consider remaining useful life and other factors, is one that Congress established through the text and structure of CAA section 111(d). See discussions in section V.B.2.<sup>43</sup> and section V.B.3.<sup>44</sup> of the December 2022 Supplemental and section XIII of the final preamble and final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

The new standards will work hand-in-hand with new resources and programs in the Inflation Reduction Act, which will incentivize early implementation of innovative methane reduction technologies and support methane mitigation and monitoring activities. These efforts will achieve greater methane emissions reductions more quickly. For more information on the IRA, the Administration has created a guidebook that provides an overview of the clean energy, climate mitigation and resilience, agriculture, and conservation-related tax incentives and investment programs, including who is eligible to apply for funding and for what activities. See <https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/>

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<sup>43</sup> 87 FR 74812.

<sup>44</sup> 87 FR 74816.

## 19.5 Review of Section 111(d) State Plans

Comment: Commenter (0844/0845-EDF) states that the proposal appropriately adheres to the CAA section 111(d) implementing regulations' criteria for completeness, technical and administrative matters, and emission inventories. The commenter believes these requirements are critical for ensuring that state plans will in practice achieve the emission reductions required under the guidelines, and no reasons exist to deviate from them here.

Response I-19-53: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (0844/0845-EDF) states that EPA has appropriately proposed to grant streamlined approval for state plans that adhere to EG OOOOc's presumptive standards (analogous to a model rule). According to the commenter, plans that do not deviate in any material way from EPA's guidelines are the likeliest to achieve the anticipated level of emission reductions, and a streamlined approval process will ensure that those reductions happen at the earliest possible time. While supporting rigorous review of state plans, the commenter believes that those that directly adhere to EG OOOOc's presumptive standards should not be subject to an unnecessary degree of administrative review when critical emission reductions are needed as soon as possible.

Response I-19-54: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required. See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines. Other timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and additional discussion in the corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

## 19.6 Proposed Timelines

### 19.6.1 Timeline for Development of State Plans

Comment: Commenter (0424-WVDEP) notes that Footnote 339 of the November 2021 proposal preamble mentions that "(t)he EPA intends to address the timing aspect of this provision in the near future" (citing 86 FR 63252). The commenter opines that this is an example of the piecemeal approach to this proposed rulemaking and asks how commenters are to provide meaningful comments when the EPA does not propose a comprehensive rulemaking.

Response I-19-55: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines. Other timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and additional discussion in the corresponding Summary of Public Comments and Responses on Proposed Rule

Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0763-TCEQ) urges the EPA to take expeditious action to address the timing provisions for state plan submission and propose a timeline for public comment. Commenter (0727-OK DEQ/OSEE) similarly states that the implementing regulations in 40 CFR part 60, subpart Ba need to be addressed now so states know what timing is going to be expected for the state plan submittal and have an opportunity to make meaningful comments.

Response I-19-56: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines. Other timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and additional discussion in the corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (0797-NDDEQ/IC) notes that EPA did not propose a timeframe for states to develop state plans but interprets the Regulatory Impact Analysis (RIA) to say that the process will take 3 years. The commenter agrees that the process will take substantial time, but states that in the absence of proposed regulatory text, they do not understand how, and cannot realistically comment on how, EPA reached this conclusion.

Commenter (0797-NDDEQ/IC) indicates that North Dakota consists of several federally recognized Indian Nations including the Mandan, Hidatsa, and Arikara Nation which has substantial oil and gas development within its borders. While the commenter does not have CAA delegation for those areas, they expect to have consultations with affected tribal authorities during the development of the state plan, and these discussions will impose additional time constraints upon North Dakota that must be considered in any proposed or final rule.

Commenter (0790-State AGs) states that the November 2021 proposal imposes an unrealistic timeframe for the states to design state plans. The commenter cites comments by the West Virginia Department of Environmental Protection (WVDEP) indicating that the sheer number of new regulated entities— and the quantity of data that these new regulations will require—would make it extraordinarily challenging for states to develop a plan in just 3 years. The commenter fears that EPA intends to use this artificial time press to open the door for more aggressive and direct regulation by the agency through promulgation of a federal plan. The commenter opines that the CAA does not anticipate this kind of significant, rushed reordering of the states' environmental regulatory structures.

Some commenters believe that EPA should allow more than 3 years for states to submit a state plan. Commenter (0763-TCEQ) believes that at a minimum, states should have 3 years for the development and submittal of a state plan, as is given under the statutory and regulatory framework a SIP. The commenter notes that in the preamble to the proposed rule, the EPA proposed completeness and approval/disapproval determinations would be based on CAA section 110. With the additional requirements proposed by the EPA for meaningful public

engagement, commenter states that more than 3 years is expected to be necessary for state plan development. The commenter adds that provisions to provide additional time upon request should also be available for states that have large numbers of applicable sources that require evaluation.

Commenter (0424-WVDEP) states that they would generally agree that 3 years is an appropriate time frame to develop a state plan for submittal to EPA based on the EG (as opposed to the nine-month time frame allowed under 40 CFR part 60, subpart B) to allow sufficient time for legislative rulemaking prior to state plan development; however, given the vast number of potential affected sources and limited state resources, commenter urges EPA to consider a longer time frame to develop an Oil and Natural Gas State Plan. The commenter cites concerns include a potential conflict with the state code regarding standards for fuels used in dwellings and the anticipated difficulty getting the political support needed to promulgate legislative rules implementing the proposed EG.

Commenter (0424-WVDEP) states that although states may have an estimate of the number of oil and natural gas wells within the state, not every well will meet the definition of an affected source. The commenter notes that considerable time is required to collect the data and evaluate almost 65,000 wells to determine whether they should be included in the state plan inventory, and that in addition to the 65,000 well sites, natural gas gathering and boosting compressor stations, processing sites, and transmission and storage sites will also require evaluation.

Commenter (0424-WVDEP) points out that the definition of an affected source [or designated facility] for storage vessels is based on a numeric emissions rate for the tank battery, therefore emissions data must be collected for each potential source prior to the evaluation to determine whether it meets the definition of an affected facility. The commenter states that at well sites, fugitive emissions above zero will meet the definition of a designated facility; however as proposed, facility designations vary based on the amount of fugitive emissions. The commenter asserts that it is not practical for the state to obtain component counts (valves, connectors, flanges, and open-ended lines) needed for fugitive emission calculations for the purposes of specifying how much each existing wellsite would be characterized in terms of fugitive emissions in advance of the state plan development. Additionally, the commenter expects the EPA to provide the emission factors and calculation methodology in the yet to be proposed regulatory text.

Commenter (0424-WVDEP) adds that the proposal to define any well liquids unloading event as a modification presents timing concerns: (1) The emissions inventory development for a state plan would be a moving target as liquid unloading events occur as part of normal well site operations, and (2) An existing and previously unregulated well that has a liquid unloading event would also require immediate compliance with the NSPS, without consideration of the time involved to design and install control equipment. For additional comments on liquids unloading operations and regulatory requirement applicability (e.g., what constitutes a modification triggering applicability of rule requirements) and EPA's response to those comments, see section 12.1 (Applicability) of Chapter 12 (Well Liquids Unloading Operations) of this document.

Finally, commenter (0424-WVDEP) notes that, in addition to the timing concerns related to the vastness of the proposal and evaluation of over 65,000 wells in the state, the proposed rule requires more involved community outreach throughout the process that will take considerable time given the 53 of the 55 counties in West Virginia have oil and natural gas activities.

Response I-19-57: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines. Other timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and additional discussion in the corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

With respect to comments citing liquids unloading provisions as an example, see discussions in section IV.F.3. Gas Well Liquids Unloading Operations of the December 2022 Supplemental<sup>45</sup> and sections X.F.3 and XI.F.3 in the final preamble.

Comment: Commenter (0831-AXPC) appreciates that EPA is committed to proposing the timeline for submittal of state plans in its forthcoming supplemental proposal and soliciting comment on this forthcoming proposed timeline. The commenter believes that it is vital for states to be given an appropriate amount of time to develop and submit their plans, although the commenter notes that they cannot take a definitive position as to how much time is required for state plan formulation and submittal until the supplemental proposal is published, to include proposed regulatory text for new EG OOOOc. However, the commenter states that the default period of 9 months, as provided for in the 1975 general implementing regulations for CAA section 111(d), is facially inappropriate here. The commenter notes that the state plan process for the existing-source rule will contain more sources than any such previous rule—potentially several orders of magnitude more—and existing facilities in this sector are likely more subject to site-specific variations than any category of existing sources that EPA has previously regulated under CAA section 111(d). The commenter asserts that an appropriate timeline here would certainly be measured in years, not months.

Commenter (0580-KDAQ) notes that EPA did not propose a specific timeline for requiring the submission of state plans in November 2021 proposal and concurs that additional time for comment is needed once EPA determines the deadline for submitting state plans under a supplemental proposal. The commenter states that additional time beyond 9 months after the final EG rule is published, as currently required by 40 CFR 60.23(a), is needed due to the extensive number of sources potentially subject to the proposed rule, the time necessary to complete state rulemaking processes, and the need for collaboration with agencies that regulate oil and gas entities in Kentucky.

Commenter (1267-CA) suggests that EPA use a framework in the current rulemaking that is similar to the long-extant timing provisions in its implementing regulations, which provided 9 months for states to submit plans and 4 months for EPA review. To account for states with a large number of designated facilities, the commenter proposes a slightly longer period for state

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<sup>45</sup> 87 FR 74781.

plan submission of 12 months after EPA’s promulgation of the final EG (with the ability to seek additional time depending on a state’s specific statutory requirements for creation and adoption of state plans); EPA’s review would then have to be completed within 4 months of a state plan submission, and federal plans would be due within 6 months of the state’s failure to submit a satisfactory plan. The commenter believes that with the design of the Proposed Rule—including its use of work practices and presumptive emission limits—states should be able to meet a 12-month submittal deadline. The commenter states that this time frame for state plan submission and for EPA review (and imposition, as necessary, of a federal plan) is also appropriate given EPA’s statement that “strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system” (citing 86 FR 63113).

Commenter (0775-CO DPHE) states that given the complexity and far-ranging nature of EPA’s proposal and considering that EPA has not yet made specific regulatory language available for review, Colorado will need time to review EPA’s final action and compare those provisions to Colorado’s own comprehensive regulatory regime for the oil and gas industry. The commenter supports giving states at least 12 months to conduct this analysis, particularly recognizing Colorado’s procedural and stakeholder engagement requirements for rulemakings, should one become necessary for Colorado to undertake.

Commenter (1294-OOCA) asserts that time is of the essence, and a 2-year deadline for the development of state plans should be more than sufficient given that implementation will take even more time. The commenter believes that a longer time period will lead to dawdling on the part of resistant states - meanwhile the climate crisis will continue to worsen.

Commenter (0941-350SV) notes that the November 2021 proposal suggested that it might take up to 3 years for states to begin implementing their EG plans for existing facilities. The commenter notes that states have known since President Biden’s Executive Order in early 2021 that they would be required to change their oil and gas industry regulations to reduce methane emissions. The commenter recommends that the deadline for EG state plans to become operational be mid-2024 (based on the commenter’s expectation that the final rule would be adopted by mid-2022). The commenter adds that more difficult parts of the plan might be delayed until 2025, but it is important to get started on implementing better performance standards as soon as possible. The commenter suggests that the EPA consider offering grants and technical assistance for developing state plans if a state agrees to implement its plan by mid-2024. Commenter (0832-NMED) notes that in New Mexico there are thousands of large and small designated facilities that would need to provide data required in 40 CFR 60.25a for the state plan. The commenter states that many owners and operators have operations in both New Mexico and other states and will be required to provide data for all their designated facilities at the same time that they are required to provide data to the State of New Mexico, which may lead to a bottleneck in states’ plan development. The commenter urges the EPA to allow states sufficient time to collect the required data for plan development and for the states to develop their plans accordingly.

Commenter (0832-NMED) also urges the EPA to allow states sufficient time to conduct thorough outreach to stakeholders, noting that states must implement a robust outreach program, which is essential to any rulemaking procedure. The commenter believes that it is crucial to



inform, and allow all public and private entities, especially those disadvantaged communities directly affected by the oil and gas sector, to be made aware of the proposed rulemaking and to provide input during the rulemaking process. In a recent rulemaking, commenter provided an initial informal comment period and an extended formal comment period to allow all interested parties the opportunity to comment on the proposed rule. The commenter requests that the EPA provide ample time to ensure a thorough and robust outreach program, which will allow for informed engagement during the rulemaking process and the potential to reduce contention during the rulemaking hearing.

Response I-19-58: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines. Other timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023, and additional discussion in the corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

#### 19.6.2 Compliance Timeline for Designated Facilities

Comment: Commenter (0844-EDF) strongly supports the proposed requirement that state plans include a compliance timeline within no more than 2 years of plan submission and urge the agency to consider whether a more abbreviated compliance timeline is warranted. The commenter notes that as proposed, EPA does not project emission reductions from the emission guidelines until 2026, but to align with the scientific imperatives and the U.S. climate commitments, it is critical these reductions occur as swiftly as feasible. Commenter states that owners and operators of existing sources are now aware that they will be required to comply with EPA standards in the coming years and will have more than 3 years to begin preparing for compliance. The commenter believes that with so much lead time, and with many of the standards (like fugitive monitoring) requiring very little time to achieve compliance in any event, a phase-in approach beyond the maximum 2-year compliance timeline EPA has proposed would be inappropriate, whereas a shorter timeframe may well be justified.

Commenter (1267-CA) states that EPA should require in its final rule that the compliance deadline for presumptive standards based on leak detection and repair be no longer than 1 year. The commenter asserts that compliance with these standards likely will not require the installation of any pollution control equipment, and LDAR using OGI is a well-established practice in the industry. Commenter notes that when EPA finalized the 2016 NSPS OOOOa standards, it required oil and natural gas sources to complete their initial leak detection surveys within 1 year.

Some commenters (0424-WVDEP, 0463-Southern Ute Tribal Council, 0573-KDHE, 0740-Utah Petroleum Association, 0782-BHE, 0790-State AGs, 0814-IPAA, 0832-NMED, 0842-WDEQ) state that the compliance timeline for designated facilities should be longer than 2 years. Commenter (0922-NAM) indicates that the compliance timeline should be at least 2 years.

Commenter (0573-KDHE) suggests that the time allowed for affected facilities to be in full compliance with the State Plan based on the proposed EGs (two years from State Plan development) is not realistic and should be extended. The commenter notes that each newly designated facility would be required to apply for and obtain an air quality permit. They added that this would "overwhelm" existing staff is a gross understatement. For sources to be in full compliance within two years, the commenter notes that the state would have to issue the air quality permits in advance of the compliance date for the sources to have regulatory requirements with which to demonstrate compliance. The newly affected designated facilities will not be subject to the federal EGs directly; therefore, the enforceable mechanism would be a new state rule and subsequent air quality permit. The commenter explains that, to issue all newly required permitting actions within the first year after State Plan submittal would require a huge amount of new permit engineers to be hired by the commenter. They add that the time to hire, train, purchase computers and other equipment for this many new employees is completely unreasonable. The commenter states that they would support an option for the EGs to require different compliance times and phase-in approaches for different designated facilities for the reasons provided above.

Commenter (0740-Utah Petroleum Association) recommends that states be encouraged to allow as much time as possible for facilities to come into compliance with regulations adopted in-state to address EG OOOOc. Otherwise, acute regional shortages may occur. EPA is soliciting comment on whether a 2-year compliance time is sufficient for complying with state plans submitted under the EGs or if it should be longer or shorter. Due to the uncertainties imposed by the supply chain shortage as well as the labor shortage, the commenter recommends that EPA allow up to three years for implementation for both existing new facilities under OOOOb and for existing facilities under the EGs, especially considering the many thousands of facilities nationwide that will be competing to obtain the same types of equipment. Furthermore, EPA should allow case-by-case extensions of the compliance dates. No one can foresee the compounding effects on supply chains and skilled labor of the vast number of facilities attempting to comply with the same rules at the same time. Case-by-case extensions to the compliance date may be the only feasible alternative for many facilities.

Commenter (0814-IPAA) states that EPA refers to the 24-month timeline for compliance with approved state regulations under EPA approved plans. Another timeline within the vacated regulations provides for states to have three years to develop their plans. EPA should retain a timeline of at least this length in its proposed Section 111(d) regulations. Regulatory development is already complicated and EPA indicates that it intends to create new mandates on the state planning process addressing EJ and community involvement actions that it wants addressed by states. The commenter suggests that there are real consequences that result from EPA's timeline choices. The commenter goes on to explain these consequences by using examples from comments made by the West Virginia DEP which generally focus on the costs that are associated with the given timeline.

Commenter (0790-State AGs) states that the November 2021 proposal imposes an unrealistic timeframe for regulated entities to implement the state plans. The commenter indicates that the 2-year proposed timeframe for implementation of this vast permitting process would compel even smaller states like West Virginia to hire thousands of new permitting engineers to finish the

job in time (citing the WVDEP comments). The commenter opines that the CAA does not anticipate this kind of significant, rushed reordering of the states' environmental regulatory structures.

Commenter (0424-WVDEP) states that the time allowed for affected sources to be in full compliance with the state plan based on the proposed EG (2 years from state plan development) is not realistic and should be extended given that each newly designated facility would be required to apply for and obtain an air quality permit, which would greatly overwhelm existing staff. The commenter indicates that for sources to be in full compliance within 2 years, the state would have to issue the air quality permits in advance of the compliance date for the sources to have regulatory requirements with which to demonstrate compliance because the newly affected designated facilities will not be subject to the federal EG directly; therefore, the enforceable mechanism would be a new state rule and subsequent air quality permit. The commenter estimates that to issue all newly required permitting actions within the first year after state plan submittal would require approximately 2,600 new permit engineers, and notes that the time to hire, train, purchase computers and other equipment for this many new employees is considerable. The commenter adds that if permitting actions spanned a 10-year period, it would still require hiring approximately 260 new permit engineers in the first year.

Commenter (0424-WVDEP) notes that assuming that an existing facility is not currently controlled, the facility would have to design, purchase, receive, install, and train operators for the controls as appropriate. Given the anticipated number of newly designated facilities, the commenter believes that there is a distinct possibility of supply chain issues, which will require longer lead times for design services or equipment. The commenter lists the following controls that may have to be added at facilities:

- Storage vessels - 95% control device
- Pneumatic controllers at wells sites and gathering and boosting stations - replace with zero emission rate controllers
- Pneumatic controllers at processing plants - instrument air system
- Centrifugal compressors - route to control to 95%
- Pneumatic pumps at processing plants - zero emissions from diaphragm and piston pumps
- Pneumatic pumps at well sites - route to control
- Associated gas from oil wells must be routed or used onsite

For the reasons provided in the comments above, the commenter (0424-WVDEP) supports an option for the EG to require different compliance times and phase-in approaches for different designated facilities.

Commenter (0842-WDEQ) disagrees with EPA's assessment that "two years is an appropriate amount of time for designated facilities to ensure compliance based on the EPA's general understanding of the industry and the proposed presumptive standards" (citing 86 FR 63256). The commenter states that without knowing the length of time that states must develop plans, a two-year compliance timeline places significant hardship on designated facilities that must scramble to meet the requirements. The commenter believes this timeline also significantly

shortchanges the amount of time necessary for state agencies to ready their respective programs (including the time and expense associated with the hiring and training of the necessary additional staff) to effectively implement the compliance schedule.

Commenter (0832-NMED) states that a 2-year compliance schedule may prove to be difficult for the designated facilities to meet. The commenter understands the urgency for designated facilities to be brought into compliance as soon as possible but given the many thousands of existing designated facilities, providing an attainable compliance deadline that sets realistic deadlines is paramount to achieving meaningful emissions reductions.

Commenter (0782-BHE) states that any compliance schedule must take into account the different milestones within the process, i.e., release of the final EG, development of state plans, EPA review of approval of the plans, state agency development of implementing regulations that supplement the state plan, and the compliance schedules therein. The commenter asserts that a compressed schedule will not allow operators adequate time to comply with state regulations and suggests that EPA should recommend a phased implementation approach that allows at least 3 years for existing source compliance.

Commenter (0782-BHE) recommends that the EG and implementation schedules consider factors that affect implementation schedules: affected operators need time to plan, develop, and implement the required programs and strategies; hire and train personnel; enter contracts with third-party service providers to conduct monitoring; and procure additional monitoring equipment. The commenter points out that the existing source regulations will affect thousands of newly affected sources, with a multitude of new requirements and affected equipment at each source, adding that build out of these systems will be time intensive.

Commenter (0463-Southern Ute Tribal Council) supports the goals of EPA's proposed rule but urges EPA to establish a realistic timeframe for compliance and implementation. Regulations should not be so rigorous that the incremental benefit of the regulations does not justify the costs and burdens of compliance (for industry) and administration (for the regulator). While not opposed to the establishment of emission guidelines to limit GHGs and VOCs from existing sources, applying such guidelines to existing sources is an especially significant change. The burden on regulators to modify permits and conduct inspections will be great. The new guidelines will disproportionately impact tribal regulatory agencies because many states have already implemented rules similar to the proposed rule. To ensure that the new rule is not unreasonably burdensome for regulators and industry, the commenter suggests a phased approach to implementation with a timeframe of five to ten years.

Response I-19-59: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0727-OK DEQ/OSEE) comments on the compliance timeline for existing well sites. The commenter states that it appears that every existing well site could need a site-specific OGI survey to confirm actual baseline methane emissions, with the baseline estimate based on major equipment counts and the process described in the GHGRP. The commenter believes that EPA's expectation that this will be accomplished within 3 years to be

problematic. The commenter recommends that EPA consider phasing in this requirement over 5-7 years based on the age of the well.

Commenter (0727-OK DEQ/OSEE) suggests that rather than requiring every well site to undergo a one-time OGI survey, EPA could consider setting a reasonable default emissions estimation approach for existing wells based on site complexity, while allowing companies to adopt more sophisticated approaches as an alternative. The commenter indicates that along with this default approach, the rule could require statistically representative spot checks to confirm the status of a subset of wells subject to the EG. The commenter believes that if properly configured, an on-going requirement for statistically representative spot checks (with OGI surveys of those facilities) could have a higher probability of detecting large emissions while reducing costs for the well operators. The commenter states that these alternatives are especially important considering the number of existing facilities that could be subject to the EG, as there are over 200,000 existing active wells in the State of Oklahoma alone. The commenter asserts that it is unreasonable to expect this number of surveys to be done in the time frame proposed.

Response I-19-60: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0425-Darrah) states that small business owners such the commenter often work on thin margins and must roll up their sleeves to keep up with additional regulations as they do not have excess capacity to throw at them. Thus, the commenter requests that small producers with higher well counts but lower hydrocarbon volumes be allowed extra time for implementation. Similarly, another commenter (0800-State of Utah) states that small businesses that own and operate the many low-producing wells within the Utah will need support and time to understand requirements, acquire and install new equipment, and make necessary procedural changes. Commenter (0800-State of Utah) encourages EPA to allow a longer implementation time for such low producing wells.

Response I-19-61: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0782-BHE) supports compliance schedules that phase in requirements and affected sources within the large number of newly affected existing transmission and storage facilities.

Response I-19-62: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0782-BHE) proposes including a phase-in period for LDAR for existing sources to ensure resources are available to conduct quarterly LDAR surveys. The commenter states that survey contractors may not be available to address the demand, especially if the proposed Appendix K methodology for OGI surveys is not significantly streamlined. Commenter recommends a multi-year phase-in period for operators to build out quarterly LDAR programs to minimize logistical issues. The commenter believes that resource availability, such as the availability of certified OGI technicians, could be significantly compromised if Appendix K is

adopted as proposed, and that even if EPA incorporates the changes to Appendix K recommended by the commenter, a multi-year phase-in period is needed to ensure that adequate time is allowed for commercial resources to meet demand.

Response I-19-63: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0739-COGC) requests that the EPA consider a 2-year phase-in approach for all existing sources as noted in the "Possible Phase-In Approach for Existing Sources" section of the November 2021 proposal because availability of equipment and subsequent inventory/supply levels are at historic lows because of unprecedented COVID-19 supply chain impacts. The commenter notes the following specific impacted designated facilities:

- Adding a new methane threshold for existing tank batteries that exceed 20 tons or more per year methane to reduce emissions by 95 percent under the proposed EG would result in a significant increase in demand for new storage vessels, capture, and control equipment, as well as associated closed tank venting and control systems.
- Proposed "Zero Bleed Rate" and other pneumatic controller revisions for existing sources will result in a significant increased demand for zero bleed equipment. Reliability and availability of alternate zero bleed options (i.e., solar powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations.
- Proposed "Zero natural gas emission rate" for pneumatic pumps and inclusion of previously exempt piston pumps for new and existing sources will result in a significant increased demand for zero emission pumps. Reliability and availability of alternate zero emission options (i.e., solar powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations.

Response I-19-64: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

Comment: Commenter (0782-BHE) states that allowing for phasing in of compliance of the EG provisions to allow case-specific review analogous to "alternative RACT" provision in ozone SIPs and consideration of case-specific economic and technological feasibility is important. The commenter recommends that the EG include a model rule or example regulatory text for the states to consider that clearly indicates case-specific applicability review and alternative RACT are allowed for existing sources. The commenter believes that it is impossible to consider the array of existing configurations that can impact emissions mitigation feasibility when developing the EG, and that prescriptive requirements could be environmentally detrimental and cost prohibitive in some cases. The commenter notes that longstanding precedent for addressing such situations is inherent in current state programs, such as alternative RACT analysis/feasibility assessment for VOC RACT or NOx RACT under ozone SIPs, and suggests an analogous process could be accessible to operators for methane regulations adopted following the EG. The commenter adds that such review can affect the permitting and compliance schedules for such sources, and schedules need to include adequate time for such actions

Response I-19-65: See section XIII.E.3 (Compliance timelines) of the final rule preamble for a discussion on the EPA's final compliance timelines.

## **19.7 Development of a Section 111(d) Federal Plan**

Comment: Commenter (0456-WDNR) states that, given the unique challenges states will face developing and implementing this proposed rule, EPA should ensure a federal plan is developed promptly according to procedural requirements outlined in 40 CFR 60.27a(c).

Response I-19-66: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required. The EPA refers the commenter to the final EPA timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023.<sup>46</sup>

## **19.8 Tribes and the Planning Process Under CAA Section 111(d)**

Comment: Several commenters (0391-KBIC, 0605-Muscogee, 0781-NTAA, 0833-UMUTEPD) note that EPA typically delays promulgating a Federal Plan until after a state fails to submit a plan, which has the potential of delaying implementation for a significant amount of time. The commenters note that only a few tribes will have the capacity to develop a tribal plan to address existing sources, so EPA will be responsible for developing a FP in much of Indian country. The commenters state that tribal communities will see more expeditious emissions reductions if EPA aggressively promulgates a FP for Indian country. The commenters indicate that a FP can expedite tribal program implementation because the FP can be delegated to interested tribes or the tribes can develop a tribal plan that, once approved, can replace the federal plan. The commenters also believe that EPA should use all available resources to help tribes address emissions from existing oil and natural gas sources in Indian country as soon as possible.

Commenter (0740-UTPA) similarly states that EPA must not delay finalizing its proposed rulemaking for controls on tribal lands, adding that any rulemaking that EPA might undertake on behalf of the Ute Tribe should be expeditious, unlike the FIP, which EPA proposed 2 years ago and, as of this writing, has not yet been sent to the White House Office of Management and Budget for final inter-agency review prior to promulgation.

Response I-19-67: The final EPA timelines can be found in the *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* at 88 FR 80480, November 17, 2023.<sup>47</sup>

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<sup>46</sup> <https://www.federalregister.gov/documents/2023/11/17/2023-25269/adoption-and-submittal-of-state-plans-for-designated-facilities-implementing-regulations-under-clean>.

<sup>47</sup> <https://www.federalregister.gov/documents/2023/11/17/2023-25269/adoption-and-submittal-of-state-plans-for-designated-facilities-implementing-regulations-under-clean>.

The EPA remains committed to working with tribes and strives to maintain consistency in its collaboration with tribes to ensure that implementation of the EG will be uniform.

Please see the final rule titled, Federal Implementation Plan for Managing Emissions From Oil and Natural Gas Sources on Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah at 87 FR 75334.<sup>48</sup>

Comment: Commenter (0740-UTPA) asserts that EPA must have sufficient consultation with the Ute Tribe to ensure that it fully supports Tribal preferences for EG OOOOc implementation on Tribal lands, noting that many of the commenter's organization's member companies operate on Tribal lands in the Uinta Basin of Utah. The commenter encourages EPA to proactively discuss the EPA rulemaking with the Ute Tribe, to fully understand the Tribe's preference for implementation, and to support the Tribal efforts while also acknowledging issues associated with a level playing field between Tribal and non-tribal lands. The commenter suggests that any rulemaking by EPA must also involve appropriate Tribal consultation to the satisfaction of the Tribe.

Response I-19-68: On November 16, 2021, EPA sent a letter to all 575 Federally Recognized Tribes inviting Tribes to participate in Tribal Consultation on the November 15, 2021 proposed rule, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Three tribes requested consultation. The following consultations were held: Tribal Consultation with MHA Nation (The Mandan, Hidatsa and Arikara Nation- Three Affiliate Tribes) on January 24, 2022; Tribal Consultation with the Northern Arapaho Tribe on January 24, 2022; Tribal Consultation with the Eastern Shoshone Tribe on January 25, 2022.<sup>49</sup> On November 14, 2022, EPA sent an additional letter to all 575 Federally Recognized Tribes inviting Tribes to participate in a follow up Tribal Consultation on the 2022 Supplemental proposed rule. The following consultations were held: Tribal Consultation with MHA Nation (The Mandan, Hidatsa and Arikara Nation- Three Affiliate Tribes) on February 7, 2023 and an informational meeting was held with the Ute Tribe on February 24, 2023.

Comment: Commenter (0463-S UTE) notes that the proposed changes to this NSPS are extensive and will require substantial financial resources if promulgated. The commenter notes that Tribes such as the commenter's, with delegations of CAA programs such as the Title V Operating Permit Program, rely on federal funding to support these programs. The commenter states that federal funding to support these programs has been inconsistent and sometimes non-existent at best. Given that tribes will face substantial financial and resource burdens if this regulation is changed as proposed, the commenter asks how the EPA proposes to ensure that tribes with these CAA delegations will receive adequate funding to support the regulation development, permitting, compliance and enforcement work that will come with this revised regulation. This is an area of significant concern to the commenter because EPA's plan in this regard will directly impact the ability of the commenter's Tribe to effectively administer this

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<sup>48</sup> [https://www.epa.gov/system/files/documents/2022-12/EPA-R08-OAR-2015-0709-0160\\_content.pdf](https://www.epa.gov/system/files/documents/2022-12/EPA-R08-OAR-2015-0709-0160_content.pdf).

<sup>49</sup> See Document I.D. EPA-HQ-OAR-2021-0317-1510.



program. The commenter looks forward to the opportunity to discuss this comment in more detail with EPA Region 8.

Similarly, commenter (0800-State of Utah) states that the new requirements of the EG will require a large investment of Utah's state resources to achieve; yet without full and equitable effort by EPA to meet a similar timeframe, the state's efforts alone cannot be effective for all the communities in the Uinta Basin. The commenter states that they would like the opportunity to work closely with Region 8 and the Ute Tribe to address future regulatory actions and planning such that the State of Utah presents a consistent and equitable regulatory environment for oil and gas sources operating within the Uinta Basin.

Commenter (1301-NATBC) similarly states that EPA should assist tribes to attain compliance with the November 2021 proposal where applicable and to develop Tribal Plans because this complex new regulation imposes considerable new requirements on resource extraction and transmission operations. Where those mandates fall on tribes or tribal partners, the commenter believes that EPA should provide funding and technical support to facilitate performance in conformity with the new proposed standards.

Commenter (1301-NATBC) states that EPA should enhance technical assistance and gap funding so that tribes have access to the necessary expertise and resources to develop Tribal Plans in adherence to the governing regulations. The commenter notes that the EG establishes requirements that tribes must follow in developing Tribal Plans and establishing, implementing, and enforcing performance standards, and also mandates that tribal standards must be at least as stringent as the EG's presumptive standards. The commenter states that such a comprehensive regulatory structure should be accompanied by commensurate EPA logistical and financial support for tribes that take on development of their own standards in adherence to the EG.

Response I-19-69: See response I-19-52 earlier in this Chapter.

Comment: Commenter (1301-NATBC) expresses concern that tribal participation in implementation of the rule relies heavily on the Treatment in a Similar Manner as States (TAS) process, which has historically been very slow, subject to litigation, and resource intensive. The commenter proposes that EPA detail the anticipated TAS process and provide robust grant funding for tribes to complete and implement the program.

Commenter (1301-NATBC) is glad to see the November 2021 proposal includes an option for tribes to exercise their inherent sovereignty by achieving TAS and developing and implementing TIPs, as provided under the CAA section 111(d). The commenter states that EPA should offer an expedited TAS and TIP development and approval process and expanded grant funding for this purpose to maximize limited tribal resources and staff capacity. The commenter notes that their experience demonstrates that the TAS process can take years and impose significant expenses and risks for tribes, including protracted litigation. The commenter indicates that the TAS and TIP should rely as much as possible on already-approved programs, to avoid redundant process.

Commenter (0794-MHAN) believes that in developing its proposed oil and gas industry methane regulations, EPA should consider mechanisms to allow greater tribal deference when developing

plans and implementing standards. The commenter supports the ability of tribes to enforce CAA programs within the exterior boundaries of the reservation but believes the process for obtaining TAS status or otherwise enforcing CAA programs should operate in support of tribes exercising sovereign authority rather than as a barrier to it. The commenter asserts that the process for obtaining TAS status for implementing CAA programs, and the NSPS in particular, has proved especially challenging for tribes, noting that as of November 2021, only two tribes had achieved TAS status to implement the NSPS. The commenter states that while the EPA maintains that tribes can develop their own plans under the November 2021 proposal, most tribes must rely on a federal plan because of EPA's restrictions on tribes' ability to obtain TAS status.

Commenter (0794-MHAN) asserts that tribes have inherent sovereign authority to regulate conduct within the boundaries of the reservation that threatens the health and welfare of tribal members (citing *Montana v. United States*, 450 U.S. 544, 565-66 (1981)). The commenter states that in promulgating the Tribal Authority Rule implementing CAA section 301(d), even though the EPA interpreted the CAA as providing tribes an express delegation of authority to regulate air resources, it still found that tribes generally "have inherent authority over air pollution sources" even on fee lands within the boundaries of the reservation (citing 63 FR 7257, February 12, 1998). While the commenter's tribe intends to pursue TAS status to implement methane regulations that effectively balance adequate environmental protections with continued oil and gas development, commenter firmly believes the CAA TAS process should operate in support of tribes exercising inherent sovereign authority to regulate air quality rather than as an obstacle to it. Moreover, the commenter opines, EPA should show greater deference to tribes in implementing clean air regulations.

Response I-19-70: Several federal environmental laws authorize EPA to treat eligible federally recognized Indian tribes as a state (TAS) for the purpose of implementing and managing certain environmental programs and functions, and for grant funding. A tribe with TAS may then oversee the specific regulatory programs for which they have TAS which are developed and adopted by the tribe for submission to, and approval by, EPA that involve an exercise of regulatory authority by the applicant tribe. This also allows the tribe the flexibility to prepare and submit a Tribal Implementation Plan (TIP). In the interim, EPA may issue a Federal Plan and at a later date the tribe could implement the rule by a future tribal plan.<sup>50</sup>

Comment: Commenter (1301-NATBC) states that the November 2021 proposal is not clear whether a single federal plan would apply to all Indian reservations without Tribal Plans or whether individual federal plans will be developed for each such Indian reservation. The commenter notes that during Northern Arapaho's January 24, 2022, consultation with EPA regarding the proposed rule, EPA representatives indicated that EPA had not yet determined how the federal plan structure for Indian reservations would work.

Commenter (1301-NATBC) advises EPA to develop individual federal plans for Indian reservations without Tribal Plans because the circumstances and remaining useful life of existing sources differ on each reservation. The commenter adds that those plans should be developed in consultation with the affected tribes. The commenter also asks that, when known, EPA provide further information on whether such plans would be reservation-specific or apply to Indian

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<sup>50</sup> <https://www.epa.gov/tribal-air/tribal-authority-rule-tar-under-clean-air-act>.

country generally, how the federal plans would be developed, whether and how such plans will differ from the standards of general application under the proposal, and the anticipated timelines for development and implementation of the plans.

Response I-19-71: The federal plan rulemaking will go through its own separate rulemaking process with opportunity for public comment and public hearing.

## Chapter 20. Emissions and Regulatory Impacts

### 20.1 Impacts of GHGs, VOC and SO<sub>2</sub> Emissions on Public Health and Welfare

#### 20.1.1 Climate Change Impacts

Comment: Several commenters (0196-Meyaard-Schaap, 0216-Montana HPHC, 0276- Greater Boston Physicians for SR, 0317-Several Organizations, 0340-Mothers and Others, 0357-NPCA, 0364-WellHead, 0401-Mercury Investments, 0414-Waterspirit, 0426-League of Women Voters, 0434-Pax World, 0435-Wespath, 0437-NY State Comptroller, 0441-Hukee, 0443-SGI, 0449-Public Employees, 0455-Radio Drama, 0458-MDE, 0460-Trinity Health, 0538-PBC, 0557-Reform Judaism, 0578-Grand Canyon Trust, 0581-NACAA, 0594-Huntsman, 0721- Moms Clean Air Force, 0769-CARB, 0794-MHA Nation, 0795-Allergy and Asthma Network, 0796-Asthma and Allergy Foundation, 0812-Ohio Farmers Union, 0917-Our Children's Trust, 0918-CO CCA, 0937- FB POWER, 0947-Several Conservation/Advocacy Groups, 0958-Climate Code Blue, 1160-United Methodist Women-SW Conference, 1267-CA AG et al, 1271-LM AME Church (Cleveland), 1282-Earthworks, 1294-OCCA, 1301-NATBC, 1302-Wyoming Outdoor Council, 1377- Lander Climate Action Network, 1389-VERIS Wealth Partners) express concern about global warming and the contribution of methane emissions from oil and gas operations contributing to climate change. In general, these commenters provide support for methane regulations that can achieve greenhouse gas (GHG) emissions reductions to mitigate the worst impacts of climate change which they report disproportionately affect low-wealth communities and communities of color. Some of these comments are provided below. Commenter (0449-Public Employees) states that, each year, the U.S. oil and natural gas industry emits 13 million metric tons of methane, a potent GHG.<sup>1</sup> EPA's Proposed Standards aim to curb these emissions – and, by extension, climate change. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (0557-Reform Judaism) states that reducing gas venting and leaks by enacting strong methane pollution standards for both large and small producers will significantly reduce methane pollution, protect frontline communities, and help address climate change.

Commenter (0918-CO CCA) expresses, that, in Colorado, climate changes are already evident. The commenter provides that the Marshall Fire in Boulder County, which occurred in late December and outside of typical fire season, was among the most damaging in the state's history, destroying nearly 1,100 homes valued at over a half billion dollars and forcing tens of thousands of residents to evacuate.<sup>2</sup> The commenter notes that local meteorologists and climate experts say drought, heavy winds, and recent warm weather created the atmosphere for the

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<sup>1</sup> Ramón A. Alvarez et al, Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain, 361 Science 6398, 186 (2020).

<sup>2</sup> Karin Brulliard, Can They Go Home Again? Wash. Post (Jan. 25, 2022), [https://www.washingtonpost.com/nation/interactive/2022/marshall-fire-colorado-rebuilding/?itid=hp-top-tablemain; Colorado Wildfire: What We Know, N.Y. Times \(Dec. 31, 2021, Updated Jan. 11, 2022\) https://www.nytimes.com/2021/12/31/us/colorado-wildfires.html](https://www.washingtonpost.com/nation/interactive/2022/marshall-fire-colorado-rebuilding/?itid=hp-top-tablemain; Colorado Wildfire: What We Know, N.Y. Times (Dec. 31, 2021, Updated Jan. 11, 2022) https://www.nytimes.com/2021/12/31/us/colorado-wildfires.html).

wildfire to flourish.<sup>3</sup> And Colorado, as with much of the West, is experiencing these types of destructive fires in increasing numbers in recent years. The commenter provides several pages on the impacts and increases in adverse climate change disruptions and problems in Colorado and nationally (e.g., increases in heat waves, droughts, water supply issues, wildfires, smoke-related particulate matter (PM), ozone and GHG pollution impacts, fire aftermath related erosion/other issues, flooding). The commenter emphasizes the potential for future adverse climate scenarios for Colorado, including the Denver metro area, Front Range cities and mountain communities.

Commenter (1282-Earthworks) contends that, to head off climate catastrophe, fossil fuel production and consumption must decline steeply and rapidly. They state that fossil fuels pose risks at almost all stages: from the moment oil and gas are pulled from the ground to final consumption, these fuels threaten our health, environment, and climate. The commenter states that, while methane emissions reductions under the Clean Air Act (CAA) are an important tool for harm reduction, the only real solution to the climate crisis is to halt fossil fuel extraction and begin a just transition by providing energy workers with family-sustaining jobs in the renewable sector.

The commenter (1282-Earthworks) suggests that the President has the authority to declare a national climate emergency, which would grant him special powers. President Biden could use it to reinstate the crude oil export ban and make it easier for federal agencies to deny permits for new infrastructure intended to facilitate oil and gas exports, including export terminals and new pipelines. They add that the White House could also direct the Department of Interior to end permitting of oil and gas extraction on public lands managed by the federal government. They argue that merely reducing methane emissions from the oil and gas industry will not make drilling and fracking safe, or natural gas “clean.” They add that rules to cut methane emissions are an important first step on the road to what is truly needed to stave off climate catastrophe. planet.

Commenter (0917-Our Children’s Trust) states that, in order for the U.S. to be in line with a < 350 ppm trajectory by 2100 [to mitigate climate impacts], there is a limited amount of natural gas that can be produced in the next 30 years to meet energy demand as fossil fuels are scaled back. The commenter suggests that, to ensure that the necessary emission reductions are achieved in the most effective and cost-effective manner and in the appropriate timeframe, EPA must plan to reduce both methane leakage and overall oil and gas production. The commenter suggests that strong rules to eliminate venting and flaring, to close loopholes allowing wells to forgo regular inspection, and to effectively plug and close operations are a start, but such regulations will simply be used to continue activities that they state scientists deem to be inconsistent with restoring Earth’s energy balance. Indeed, the commenter adds that the oil and gas industry often points to their efforts to contain methane leakage as a justification for ongoing operations, which does not account for the ongoing production of a dangerous product. As control devices are known to fail, the commenter requests that companies be held accountable for GHG emissions that result from their activities, including from abandoned unplugged wells. The commenter also states that the EPA must also develop a plan to end these operations and wind down oil and natural gas production. During this phase out period, the commenter

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<sup>3</sup> High winds, severe drought, and warm temps led to Colorado's historic wildfire, NPR (Dec. 31, 2021) <https://www.npr.org/2021/12/31/1069416715/colorado-marshall-fire-caused-by-high-winds-drought>.

recommends that only companies with a successful track record for achieving maximum emission reductions be permitted to continue operating to meet the amount of oil and gas that is needed to be produced to meet our energy demands in a way that is consistent with achieving the <350 ppm target.

Commenter (0216-Montana HPHC) asserts that wildfires demonstrate all too well how climate change is a threat multiplier, amplifying other processes that already exist. The commenter states that, in the case of wildfires increased temperatures from climate change result in drier soils, increased evapotranspiration from plants and trees, and less winterkill of pests that also can spread across a broader range, thereby worsening the conditions created by ill-advised forest management decisions of the past hundred years. The commenter notes, as health care providers, all that results in them having to warn patients who they care for about the potential for wildfire smoke to worsen lung diseases like asthma, cause heart attacks and strokes, and even affect fetuses still in their mothers' wombs or cause preterm labor. The commenter adds that they also warn parents not to allow their children to play and exercise outside for large parts of the summer and to seek safe havens from the smoke; safe havens that don't exist for many.

The commenter (0216-Montana HPHC) adds that the effects are more far reaching than just the smoke and ash. As reported by Bloomberg News today, a recent example comes from British Columbia, devastated by wildfires this summer, then again by torrential downpours in recent weeks, along with the northwest U.S. While not everyone lost homes to the fires or floods, the commenter states that tens of thousands were affected. The forest fires killed trees, which loosened soil, which led to mudslides in the torrential downpours; downpours predicted by climate models. The mudslides shut down critical rail lines from the Port of Vancouver, a major shipping center from Asian markets, where large portions of Christmas-bound consumer goods are manufactured. Flooding and fire have also presented barriers to Christmas-tree exports, for which Canada is the world's largest exporter, the US being its largest customer.

Commenter (0937-FB Power) contends that the EPA has the authority, and oil and gas companies have the tools and technology, to cut methane pollution 65% below 2012 levels by 2025.

Commenter (0594-Huntsman) states that the impacts from GHG emissions "are changing the climate at a pace and in a way that threatens human health, society, and the natural environment," and "emissions from human sources have already more than doubled." Methane is a critical GHG which the Intergovernmental Panel on Climate Change (IPCC) has characterized as a short-lived climate forcer (SLCF). As the 2021 November proposed rule explains, "[o]ne ton of methane in the atmosphere has 80 times the warming impacts of a ton of carbon dioxide [CO<sub>2</sub>] and contributes to the creation of ground-level ozone." Reducing methane emissions has been identified as "one of the best opportunities for reducing near term warming" with "the potential to limit temperature rise." According to the commenter, the need is immediate, particularly when one considers that the 2020 concentration of methane "was almost 13 ppb over 2019, the largest annual increase in methane concentrations of the period since the early 1990s."

Commenter (0812-Ohio Farmers Union) states that agriculture, food, and related industries contributed more than \$1.1 trillion to the U.S. economy annually in 2019 and provided 19.7

million full- and part time jobs in 2020. However, the commenter adds that the future of their industry is at stake if they do not take bold and commonsense action to cut climate change. The commenter notes that sustained, severe drought in the West is already threatening the water supplies they depend upon for their crops and livestock. In 2021, the commenter reports that the Colorado River had the first-ever water shortage leading to supply cuts for western farmers. In the Midwest and East, strange and severe weather events have flooded farmland. The commenter adds that drought and flooding have already cost the agricultural industry billions of dollars and put into question the future livelihood of farmers and ranchers everywhere. They further add that increased temperatures and changing climates will also lead to an increased range of pests, more disease and lower crop and livestock yields.

Commenter (0578-Grand Canyon Trust) reports that the Colorado Plateau is home to over 50,000 active oil and gas wells, and over 8,000 abandoned/orphan oil and gas wells. Collectively, the commenter states that these wells generate nearly a fifth of Colorado Plateau counties' GHG emissions. The commenter adds that the Four Corners region sits beneath a methane cloud, of which 66-75% comes from natural gas and coal bed methane operations in the San Juan Basin, and another 5% from oil and gas to the south in New Mexico.<sup>4</sup>

Commenter (0357-NPCA) states that the leaking, venting and flaring of methane from oil and gas production contributes to climate change, harming people, wildlife and our lands and waters, including the places and resources that make up the 423 units of our national park system. Methane and other air pollution (like volatile organic compounds, or VOCs) from oil and gas operations contributes to ground-level ozone in places like Carlsbad Caverns and Joshua Tree national parks. These pollutants combine to produce smog marring scenic views and can lead to asthma attacks and other respiratory ailments. High levels of ground-level ozone can also harm plants and trees, like the quaking aspen in Rocky Mountain National Park. According to the commenter, in the over 100 years since the creation of the National Parks Conservation Association (NPCA), parks and their dependent communities have never faced a threat on the scope or scale of the unfolding impacts of the climate crisis. The commenter contends that, from historic structures lost to fire, coastal communities and ecosystems destroyed by sea level rise and hurricanes and species pushed to extinction from loss of habitat, the cultural and natural landscapes we work to protect have never known change at the current pace and scale. The commenter concludes that addressing the host of harmful pollution from the oil and gas sector is critical for national parks and the values they represent.

Similarly, commenter (0441-PLS) suggests that with the growth in remote work and skyrocketing demand for outdoor access, healthy public lands are bringing both visitors and business investment to rural communities across the country. But this important economic driver is threatened when methane from oil and gas development is not properly managed. For this reason, our businesses support a strong EPA Methane Rule that protects our nation's environment and supports outdoor recreation on shared public lands. The commenter adds that we also need a strong methane rule to reduce air and climate pollution to give rural communities

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<sup>4</sup> National Oceanic and Atmospheric Administration (NOAA) Research. NOAA Research News. US methane "hotspot" is snapshot of local pollution. November 24, 2020. Available at: <https://research.noaa.gov/article/ArtMID/587/ArticleID/2691/US-methane-%E2%80%9Chotspot%E2%80%9D-issnapshot-of-local-pollution>.

a future and ensure that all Americans will continue to enjoy hiking, biking, swimming, climbing, skiing, and rafting on our federal and native lands.

Commenter (0364-WellHead Systems) states that methane emissions by itself is 90 times more potent than CO<sub>2</sub> which is thought to be the leading cause of climate change.

Commenter (0437-NY State Comptroller) states that climate change poses significant risks and opportunities. To address these risks and opportunities, the commenter notes that it has adopted a Climate Action Plan involving company and investment manager assessments and engagements, a dedicated sustainable investment program, and support for climate risk mitigation policies.<sup>5</sup> The commenter notes that sound methane regulation at the national level is essential to mitigating the worst effects of climate change. Given methane's global warming potential (80 times that of CO<sub>2</sub> over a 20- year period) and the significant percentage of anthropogenic methane emissions emitted by the oil and gas industry (30 percent), the commenter asserts that the EPA proposal to regulate this industry's emissions is a crucial step in avoiding the worst impacts of climate change and can contribute significantly to the reduction of near-term warming.<sup>6</sup> The commenter adds that Federal regulation of methane will also benefit investors by providing certainty to companies and lowering the overall GHG intensity of oil and gas produced in the U.S. This will make U.S. oil and gas products more attractive to a global marketplace that increasingly requires reductions in GHG intensity. Clear and consistent methane regulations can achieve GHG emissions reductions while simultaneously helping American industries become cleaner and more competitive.

Commenter (0557-Reform Judaism) expresses that methane's impact is twenty-five times greater than CO<sub>2</sub> over a 100-year period. Methane accounts for 10 percent of U.S. GHG emissions, with about one-third of those emissions coming from the oil and gas industry.

Commenters (0406-Boone, 0538-PBC) At least a quarter of today's global warming is caused by methane emissions from human sources. Commenters (0455-Radio Drama, 0460-Trinity Health, 0538-PBC) note that methane is a short-term climate forcer, 86 times more potent than CO<sub>2</sub> over a 20-year period. Commenter (0406-Boone) states that activities relating to the oil and gas industry release approximately 16 million metric tons of methane into the atmosphere annually. The commenter notes that reducing methane pollution from the oil and gas industry is the fastest, most cost-effective way to slow reduce GHG emissions – and comes with broad support from the industry, the banking community, the environmental community, and members of the sportsmen and women's community.

Commenters (0401-Mercury Investment, 0434-Impax Asset, 0435-Wespath, 0443-SGI, 0460-Trinity Health, 0538-PBC, 1388-Private Citizen, 0795-ALA et al) reference the recent IPCC report that identifies methane pollution as one of the key drivers of climate change and underscores the urgent need for protective action to reduce methane emissions and limit global warming.

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<sup>5</sup> <https://www.osc.state.ny.us/files/reports/special-topics/pdf/climate-action-plan-2019.pdf>

<sup>6</sup> Overview of Greenhouse Gases, United States Environmental Protection Agency, available at: <https://www.epa.gov/ghgemissions/overview-greenhouse-gases#methane>



Commenters (0399-Garden Club of America) assert that methane's contribution to climate change was underestimated until recently, in part given its much smaller concentration in the atmosphere relative to CO<sub>2</sub>. But because methane has a radiative forcing factor 80 times that of CO<sub>2</sub> in the short term (20 years), it has a powerful impact. The commenters state that scientists estimate that 25% to 30% of the warming occurring today is caused by methane emissions, second only to CO<sub>2</sub>. The commenters add that concentrations of methane reached 1879 parts per billion in 2020, which is more than two and a half times the pre-industrial concentration of 722 parts per billion.

Commenters (0399-Garden Club of America) report that methane also contributes to climate change by causing atmospheric chemical reactions, producing tropospheric ozone and stratospheric water vapor. According to the commenters, it is estimated that about half of ozone increases since the pre-industrial era have been created by these methane atmospheric interactions.

Commenter (0391-KBIC) supports the White House Office of Domestic Climate Policy's Methane Emissions Reduction Action Plan, including the significant role of EPA in that Plan. The commenter agrees that significantly reducing methane in the oil and natural gas industry will generate significant climate benefits as well as direct health benefits to communities harmed by local and regional emissions. The commenter adds that they support efforts from the EPA and other federal agencies to reduce emissions from the entire oil and natural gas industry, including extraction and production, processing, transmission, and distribution.

Commenter (0398-House of Representatives) expresses that there is no time to waste in curbing methane pollution and tackling the climate crisis. The commenter asserts that our children's health, the safety of those living in oil and gas communities, and the future of the planet all hang in the balance. We must tackle this growing crisis head on before it is too late.

Commenter (0186-Snoqualmie Tribe) states that they are already negatively affected by climate change and are doing what they can to plan for and adapt to the changes that are coming. (<https://iopscience.iop.org/article/10.1088/1748-9326/abf393/meta>). The commenter supports reducing pollution through rulemaking as proposed. The commenter emphasizes that there is an overarching and overpowering need to begin to diminish our collective pollution of our planet, including humans' industrial contributions to climate change, which the proposed performance standards would support.

Commenter (1388-W.L.) contends that climate change is the biggest threat that humankind has ever faced. The commenter notes that climate changes will especially negatively impact the very young, and the yet to be born, who will follow us, and will inherit a diminished and hostile world that we have passed on to them. The commenter emphasizes that it is essential that we stop discharging methane, CO<sub>2</sub>, and other GHGs as soon as possible. The commenter recommends that rule be improved to further limit GHG emissions than the rule currently requires and prohibiting all GHG emissions within 3 years. Although they acknowledge this would be difficult, they contend it is necessary.

Commenter (0351-Columbia) reports that the most recent IPCC report states that reducing methane emissions is a major opportunity to slow climate change quickly. The commenter states that cutting methane emissions is a major opportunity to slow the rate of global warming in the coming decades. The commenter suggests that reducing methane and co-pollutant emissions from oil and gas wells could immediately improve public health and environmental justice concerns nearby and slow long-term climate change that threatens our species.

Response I-20-1: EPA agrees with commenters that methane is a powerful greenhouse gas. Methane is 28 times as potent as CO<sub>2</sub> over a 100-year time frame, and historical emissions of methane have contributed about a third of today's warming. Methane also contributes to increases in global tropospheric ozone levels, which damages human health and ecosystems. This action will contribute to reductions in methane emissions.

Comment: Commenter (0597-IN OGA) notes that, according to a White Paper published by two atmospheric physicists W. A. van Wijngaarden of York University, Canada, and W. Happer of the Princeton University Department of Physics, "methane contributes only about 30/300 or 1/10 of the already small warming from CO<sub>2</sub>". The commenter states that the White Paper provides calculations demonstrating the small impact of methane emissions on the environment as a basis that methane emissions should not be regulated due to potential global warming potential. The commenter asserts that, while many comments have been submitted to EPA that recite the same talking points about methane's global warming potential, Wijngaarden and Happer provide the calculations to demonstrate the small impact that methane has on the atmosphere.

Response I-20-2: Methane is a powerful greenhouse gas. Methane is 28 times as potent as CO<sub>2</sub> over a 100-year time frame, and historical emissions of methane have contributed about a third of today's warming. Methane also contributes to increases in global tropospheric ozone levels, which damages human health and ecosystems. This action will contribute to reductions in methane emissions. See Response I-20-8 for a more detailed response to the cited White Paper.

### ***20.1.2 Adverse Health Impacts***

Comment: Several commenters (0195-EEN, 0196-Meyaard-Schaap, 0199-ALA et al) 0215-EEN, 0276-Greater Boston Physicians for SR, 0340-Mothers and Others, 0351-Columbia, 0370-NM State Rep, 0385-Silent Spring, 0414-Waterspirit, 0440-Missionary Sisters, 0444-DCS, 0458-MDE, 0559-Texas State Senator, 0578-Grand Canyon Trust, 0581-NACAA, 0721-Moms Clean Air Force, 0733- Conservation Voters of NM, 0734-ATS, 0753-IGSD et al, 0794-MHA Nation, 0795-Allergy and Asthma Network, 0796-Asthma and Allergy Foundation, 0844-EDF et al, 0949- Liveable Arlington, 1267-CA AG et al, 1294-Occa, 1301-NATBC, 1302-Wyoming Outdoor Council) express concern regarding, and/or provide studies and references supporting, the adverse health impacts associated with exposure to emissions from oil and natural gas operations. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (1267-CA AG et al) states that robust enforcement of the final rule will be critical to achieving the rule's significant emission reductions of methane, VOC, and hazardous air

pollutants. The State Attorneys' General who signed the comment are interested in using their enforcement authority in collaboration with EPA and the Department of Justice to see those pollution reductions are realized.

Commenter (1301-NATBC) contends that the proposed rule has implications for the health of the Northern Arapaho people. Northern Arapaho Tribal members who reside on the Wind River Reservation live near oil and gas operations, which can degrade air quality, threaten water quality, and contaminate soil among other environmental harms. The commenter notes that they know firsthand how the burdens of resource extraction fall disproportionately on tribal peoples, while the lion's share of profits from those activities have not remained in our community to benefit our people.

Commenter (0844-EDF et al) references a longstanding body of scientific research, including numerous EPA assessments, that demonstrate that exposure to ground-level ozone harms human health. These effects range from decreases in lung function among healthy adults to increases in

respiratory-related hospital admissions and emergency room visits, to premature death.<sup>7,8,,9,10,11,12,13,14,15,16,17,18,19,20,21,22,23,24,25,26</sup>

The commenter also provides that EPA has also cataloged the harmful effects of benzene and other specific air toxics emitted from oil and gas operations, including toluene, carbonyl sulfide, ethylbenzene, mixed xylenes, n-hexane, and other air toxics.<sup>27</sup> The commenter adds that there are several studies that suggest that the proximity to oil and gas development is associated with adverse health outcomes. They note that there are over 120 million people living in ozone non-

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<sup>7</sup> 2013 Final Report: Integrated Science Assessment of Ozone and Related Photochemical Oxidants (“ISA”) (EPA/600/R-10/076F) at 1-6.

<sup>8</sup> Id. at 6-131 to 6-158, 6-162 to -163.

<sup>9</sup> Stephanie Holm, John Balmes, Ananya Roy, Human Health Effects of Ozone: The State of Evidence Since EPA’s Last Integrated Science Assessment, EDF 2018.

<sup>10</sup> Available at [https://www.cdc.gov/asthma/most\\_recent\\_national\\_asthma\\_data.htm](https://www.cdc.gov/asthma/most_recent_national_asthma_data.htm), last accessed on Jan. 27, 2022.

<sup>11</sup> Tursynbek Nurmagambetov, Robin Kuwahara, Paul Garbe, The Economic Burden of Asthma in the United States, 2008 – 2013, *Annals of the American Thoracic Society*, 2018).

<sup>12</sup> Susan C. Anenberg, Daven K. Henze, Veronica Tinney, Patrick L. Kinney, William Raich, Neal Fann, Chris S. Malley, Henry Roman, Lok Lamsal, Bryan Duncan, Randall V. Martin, Aaron van Donkelaar, Michael Brauer, Ruth Doherty, Jan Eiof Jonson, Yanko Davila, Kengo Sudo, Johan C.I. Kuylenstierna, Estimates of the Global Burden of Ambient PM2.5, Ozone, and NO2 on Asthma Incidence and Emergency Room Visits, *Environmental Health Perspectives*, 2018; 126 (10): 107004.

<sup>13</sup> ISA at 1-8, 7-2.

<sup>14</sup> Wang, Meng, et al. Association between long-term exposure to ambient air pollution and change in quantitatively assessed emphysema and lung function. *JAMA* 322.6 (2019): 546-556.

<sup>15</sup> Yazdi, Mahdih Danesh, et al. "Long-term exposure to PM2. 5 and ozone and hospital admissions of Medicare participants in the Southeast USA." *Environment international* 130 (2019): 104879.

<sup>16</sup> Xu X, Sun Y, Ha S, Talbott EO, Lissaker CT, Association between ozone exposure and onset of stroke in Allegheny County, Pennsylvania, USA, 1994-2000, *Neuroepidemiology*, 2013; 41(1):2-6.

<sup>17</sup> Wing JJ, Adar SD, Sánchez BN, Morgenstern LB, Smith MA, Lisabeth LD, Short-term exposures to ambient air pollution and risk of recurrent ischemic stroke, *Environmental Research*, Jan. 2017; 152:304-7.

<sup>18</sup> Shah, Anoop SV, et al., Short term exposure to air pollution and stroke: systematic review and meta-analysis, *BMJ* 350 (2015): h1295; Yang, Wan-Shui, et al., An evidence-based appraisal of global association between air pollution and risk of stroke, *International Journal of Cardiology* 175.2 (2014): 307-313.

<sup>19</sup> ISA at 1-14 (concluding that there is “likely to be a causal relationship between short-term exposures to [ozone] and total mortality”).

<sup>20</sup> EPA, National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65,292, 65,307 (Oct. 26, 2015); see also ISA 6-220 to 6-221.

<sup>21</sup> Mendola et al., Chronic and Acute Ozone Exposure in the Week Prior to Delivery is Associated with the Risk of Stillbirth, 14 *INT’L J. ENV’T L RESEARCH AND PUB. HEALTH* 731 (2017).

<sup>22</sup> Laurent O, Hu J, Li L, et al. A statewide nested case-control study of preterm birth and air pollution by source and composition: California, 2001-2008. *Environ Health Perspect.* 2016;124(9):1479-1486; Ha S, Hu H, Roussos-Ross D, Haidong K, Roth J, Xu X. The effects of air pollution on adverse birth outcomes. *Environ Res.* 2014;134:198-204.

<sup>23</sup> Becerra, Tracy Ann, et al, Ambient air pollution and autism in Los Angeles county, California, *Environmental Health Perspectives* 121.3 (2012) 380-386; Volk HE, Lurmann F, Penfold B, Hertz-Picciotto I, McConnell R, Traffic-related air pollution, particulate matter, and autism, *JAMA Psychiatry* (Jan. 1, 2013); 70(1):71-7.

<sup>24</sup> Galkina Cleary et al., Association of Low-Level Ozone with Cognitive Decline in Older Adults, 61 *J. ALZHEIMERS DISEASE* 1, 67-78 (2018).

<sup>25</sup> ISA at 1-8.

<sup>26</sup> K. Mortimer et al., The Effect of Air Pollution on Inner-City Children with Asthma, 19 *EUR. RESPIRATORY J.* 699 (2002), ISA, 6-120–21, 6-160.

<sup>27</sup> 2021 PRIA. at 3-23 to -26.

attainment areas in the U.S. according to EPA calculations<sup>28</sup> and nationwide, it is estimated that almost 18 million people live within 1 mile of at least one active oil and/or gas site.<sup>29</sup> The commenter adds that new studies document associations between such proximity to nonconventional oil and gas development and negative human health effects generally and provides several example studies (see pages 33 to 35 of the commenters' comments).

Commenter (0276-Greater Boston Physicians for SR) reports that the gas emitted at compressor stations or leaked in our streets or burned in our gas stoves or furnaces is a mixture of methane and hexane (a neurotoxin); but it is likely that many of the observed health outcomes are due to what travels with it: things like benzene and formaldehyde, both known carcinogens; metals and radionuclides from the Earth's crust that can include (depending on the geographic region from which methane is extracted) lead, mercury and radioactive radon, uranium and thorium that are highly harmful to human health; and the criteria air pollutants produced in the burning of methane gas, like ground level ozone and particulate matter. The commenter adds that there is a wealth of peer-reviewed studies that provide documentation of the health hazards of natural gas infrastructure: asthma, COPD, childhood acute lymphocytic leukemia, miscarriage, congenital heart defects and increased premature birth. These are best defined at the drill rig, where more babies being born prematurely; more babies with heart defects, more kids with asthma; more children diagnosed with leukemia. The commenter states that there are also many other recorded health effects: increased pneumonia in those living near natural gas infrastructure; increased heart disease; increased thyroid and bladder cancer.

Commenter (1302-Wyoming Outdoor Council) reports that volatile organic compounds (VOCs), ozone, and other pollutants can increase the risk of chronic respiratory issues like asthma, and even short-term exposure can cause acute symptoms like headaches and dizziness.<sup>30</sup> Furthermore, the commenter states that Wyoming residents are not protected by adequate setback distances. Oil and gas operations can be located as close to homes as 500 feet. According to a 2019 Colorado Department of Health Study, health risks from oil and gas operations are elevated for people who live within 2000 feet of an oil or gas pad, including an elevated risk of cancer.<sup>31</sup> According to the commenter, stronger rules to reduce methane emissions like those proposed here would have the beneficial effect of reducing VOC emissions and the risk of ozone formation as well, a critical step in protecting the health of citizens and communities living near oil and gas operations.

Commenter (1160-United Methodist Women – SW Conference) reports that, in Arizona, there are 6,572 childhood asthma attacks a year due to oil and gas ozone smog. They add that there are 4,791 school days lost to oil and gas ozone smog. They contend that this is the result of 39 oil

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<sup>28</sup> EPA, Summary Nonattainment Area Population Exposure Report (2021) <https://www3.epa.gov/airquality/greenbook/popexp.html>.

<sup>29</sup> Eliza D. Czolowsk et al., Toward Consistent Methodology to Quantify Populations in Proximity to Oil and Gas Development: A National Spatial Analysis and Review, 125 *Env'tl. Health Perspectives* 6, available at <https://doi.org/10.1289/EHP1535>.

<sup>30</sup> ICF. 17 Oct 2019. "Final Report: Human Health Risk Assessment for Oil and Gas Operations in Colorado." <https://www.fcgov.com/oilandgas/files/20191017-cdphe-healthimpactsstudy.pdf>

<sup>31</sup> *Id.*

and gas facilities in our state. They report that 925 students live within the threat radius, and there are 2 schools threatened by these pollutants.

Commenter (0370-NM State Rep) reports that the concentration of methane in the San Juan Basin is the highest in the nation and is a safety concern for the workers, families, and the whole community in this area. The commenter asserts that the pollution emitted is particularly troubling and is causing a public health emergency. They note that the Air Quality Bureau has recorded levels of ozone that have come close to the National Ambient Air Quality Standards for Ozone in the San Juan Basin. In the American Lung Association's 2021 State of the Air Reports, New Mexico's top oil-and-gas producing counties, those where the San Juan and Permian Basins are located, received an f grade for ozone pollution.

Commenter (0734-ATS) states that, acting as a respiratory irritant with oxidative potential, ozone can trigger cough in healthy individuals, lead to exacerbations of pre-existing respiratory diseases (COPD and asthma), and is even a risk factor for the development of asthma and decreases in lung growth and function in children.<sup>32,33,34</sup> They add that pulmonary inflammation caused by long-term ozone exposure leading to systemic inflammation is one underlying cause of the increased mortality risk from cardiac and pulmonary diseases.<sup>35</sup> In addition to the decades of ozone research on cardiopulmonary disease, the commenter notes that emerging research on the association between ozone exposure and an increased risk of Alzheimer's disease has raised concern for the neurocognitive risks of ozone.<sup>36</sup> The commenter adds that there is also emerging data linking increased ground-level ozone with increased mortality in COVID infection,<sup>37,38</sup> which may be related to upregulation of genes and molecular pathways associated with severe COVID-19.<sup>39</sup> The commenter concludes that, overall, the contribution of methane and VOC emissions to increased ozone concentrations can cause serious health consequences nationwide. The commenter contends that the proposed rule will be of particular benefit in rural communities that struggle with elevated wintertime ozone levels. They add that the VOC emission reductions that will accompany actions taken under the proposed rule will result in meaningful

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<sup>32</sup> Hwang, B-F; Chen, Y-H; Lin, Y-T; Wu, X-T & Lee, YL. Relationship between exposure to fine particulates and ozone and reduced lung function in children. *Env. Res* 137, 382– 390 (2015). Dimakopoulou, K; Douros, J; Samoli, E; Karakatsani, A; Rodopoulou, S; et al. Long-term exposure to ozone and children's respiratory health: Results from the RESPOZE study. *Env. Res* 182, 109002 (2020).

<sup>33</sup> Zhang, J; Wei, Y & Fang, Z. Ozone Pollution: A Major Health Hazard Worldwide. *Front Immunol* 10, 2518 (2019).

<sup>34</sup> Dimakopoulou, K; Douros, J; Samoli, E; Karakatsani, A; Rodopoulou, S; et al. Long-term exposure to ozone and children's respiratory health: Results from the RESPOZE study. *Env. Res* 182, 109002 (2020).

<sup>35</sup> Lim, CC; Hayes, RB; Ahn, J; Shao, Y; Silverman, DT; et al. Long-Term Exposure to Ozone and Cause-Specific Mortality Risk in the United States. *Am J Respir Crit Care Med* 200, 1022–1031 (2019).

<sup>36</sup> Jung, C-R; Lin, Y-T & Hwang, B-F. Ozone, Particulate Matter, and Newly Diagnosed Alzheimer's Disease: A Population-Based Cohort Study in Taiwan. *J Alzheimers Dis* 44, 573–584 (2015).

<sup>37</sup> Li, C & Managi, S. Impacts of air pollution on COVID-19 case fatality rate: a global analysis. *Env. Sci Pollut Res Int* Jan 4, 1–14 (2022).

<sup>38</sup> Liu, S & Li, M. Ambient air pollutants and their effect on COVID-19 mortality in the United States of America. *Rev Panam Salud Publica* 44, e159 (2020).

<sup>39</sup> Vo, T; Paudel, K; Choudhary, I; Patial, S & Saini, Y. Ozone exposure upregulates the expression of host susceptibility protein TMPRSS2 to SARS-CoV-2. *Sci Rep* 12, 1357 (2022).

improvements in ambient ozone concentrations in communities with few other policy options to address this health risk.

Commenter (0733-Conservation of Voters of NM) reports that a comment provided by Dr. Brita Lundberg, who is the Chair of the Board of Greater Boston Physicians for Social Responsibility, pointed out that the gas emitted at compressor stations or leaked or burned in gas furnaces and stoves is a mixture of methane and hexane – which is a neurotoxin – and that many of the effects of that gas are due to the benzene, formaldehyde, and other substances that travel with the gas. As another example, the commenter states that the Silent Spring Institute’s comment explained that VOCs are a primary precursor to tropospheric ozone pollution, which is recognized as a concern for human health because it contributes to respiratory disease, congestive heart failure, and lung cancer.

Commenter (0578-Grand Canyon Trust) notes that methane unintentionally escapes and is intentionally released (through venting and flaring) during extraction and processing of natural gas. The commenter adds that when methane is released either intentionally or unintentionally from these operations, it is accompanied by VOCs and hazardous air pollutants (HAPs), and ground level ozone all of which adversely affect human health, especially tribal communities across the Colorado Plateau. Ozone harms human health and depending on the level of exposure, can aggravate lung diseases and increase the frequency of asthma attacks. It is also associated with death from respiratory complications.<sup>40</sup> The United Nations Environment Programme found that reducing human caused methane emissions would prevent 255,000 premature deaths each year, 775,000 asthma related hospital visits.<sup>41</sup>

Commenter (0753-IGSD et al) suggests that, given the health risks associated with oil and gas development, states are increasing required setback distances. The commenter notes that the location of wells (whether active or abandoned) in residential communities, near vulnerable populations or in the proximity of schools, hospitals, and other buildings where people congregate, poses serious health risks to communities, especially disadvantaged communities which already suffer from systemic historical discrimination. As of October 2021, the commenter reports that California’s governor Newsom proposed to require a “setback” distance of 3,200 feet for new wells from sensitive community locations, and more pollution control regulations for wells already existing within this distance.<sup>42</sup> According to the commenter, this is

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<sup>40</sup> U.S. Environmental Protection Agency. Health Effects of Ozone Pollution. Available at <https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution>.

<sup>41</sup> United Nations Environment Programme and Climate and Clean Air Coalition (2021). Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. Available at: <https://www.ccacoalition.org/en/resources/global-methane-assessment-summary-decision-makers>. At 5.

<sup>42</sup> California Officer of Governor (21 Oct. 2021) California Moves to Prevent New Oil Drilling Near Communities, Expand Health Protections, Press Release (“Moving to protect communities as the state works to phase out fossil fuels, Governor Gavin Newsom today announced that the Department of Conservation’s Geologic Energy Management Division (CalGEM) has released a proposed regulation that would prohibit new wells and facilities within a 3,200-foot exclusion area – or setback – from homes, schools, hospitals, nursing homes and other sensitive locations. It would also require pollution controls for existing wells and facilities within the same 3,200-foot setback area.”) (“The state is proposing a 3,200-foot setback in order to protect public health. A 15-member public health expert panel selected by University of California, Berkeley and Physicians, Scientists, and Engineers (PSE) for Healthy Energy helped inform the draft rule announced today. The panel concluded that when oil and gas

the greatest set-back distance proposed thus far, demonstrating a fix to a historical public health issue experienced nationwide. The commenter recommends that stringent federal standards be developed to complement these efforts and protect communities from the harms of oil and gas production.

Commenter (0557-Reform Judaism) states that pollution from methane contributes to contaminated air and increased health issues like asthma, especially for those living near oil and gas facilities.

Commenter (0402-Cancer Free) states that they are specifically concerned with rising cancer rates—it is now estimated that one in three people in the U.S. will be diagnosed with cancer at some point in their lives<sup>43</sup>—and a growing body of research points to chemicals in our environment as important, and preventable, risk factors for cancer.<sup>44</sup> Per EPA’s analysis, the primary proposed NSPS OOOOb and EG OOOOc rules under the proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector are expected to reduce the combined emissions of methane by 41 million short tons, VOCs by 12 million short tons, and HAPs by 0.48 million short tons between 2023 and 2035 alone.<sup>45</sup> According to the commenter, these emission reductions are specifically significant, and vitally necessary, given the health impacts of these three emission classes (which they outline in several paragraphs of their comment letter describing the health effects related to methane, VOC and HAP emitted from oil and gas operations).

Commenter (0414-Waterspirit) states that humans are suffering physically and mentally from the ill effects of undisclosed chemicals used in natural gas infrastructure, such as the highly potent GHG, methane. New Jersey is home to the first landmark legislation that considers cumulative environmental impact and related health impacts to burdened communities prior to awarding permit approval for proposed projects. The evaluation of health impacts afflicting children and expectant mothers is necessary given the clear linked evidence to undisclosed chemicals gone unregulated and unchecked. November 19th, 2021 “Air Pollution Can Alter Our Brains In Ways that Increase Mental Illness Risk: Emerging research finds polluted air linked to mental health problems, leaving Western Pennsylvania children and environmental justice communities at high risk.” (Kristina, Marusic, Environmental Health News) On October 27th, 2021, an event took place entitled “The Real Voices of the Marcellus Shale.” The story of a Pennsylvania mother whose 19-year-old son succumbed to fossil fuel emissions related cancer was shared. Cancer is

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developments are within 3,200 feet, there is a strong connection to higher rates of adverse birth outcomes, respiratory diseases such as asthma, and heart disease, among other health impacts. The panel’s research supports both moving oil production farther away from communities in combination with pollution controls for operating wells.”)

<sup>43</sup> Siegel, R. L., Miller, K. D., & Jemal, A. (2019). Cancer statistics, 2019. CA: A Cancer Journal for Clinicians, 69(1), 7-34. doi:10.3322/caac.21551.

<sup>44</sup> Cohen, L., & Jefferies, A. (2019). Environmental exposures and cancer: using the precautionary principle. *Ecancermedicalscience*, 13, ed91. doi: 10.3332/ecancer.2019.ed91.

<sup>45</sup> U.S. Environmental Protection Agency. (2020). Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. Office of Air Quality Planning and Standards Health and Environmental Impacts Division. [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf).



costly and mental anguish for survivors is cumulative and permanent. Preventable death and grief alone demonstrate time and again the true costs of pollution. Providing subsidies to fossil fuel companies for decades - and ongoing - helps ensure carbon schemes and resulting permanent damage to once healthy aquifers, communities, family, life. Children see these priorities being made.

Commenter (0317-Several Organizations) states that methane and its by-products have well known, deleterious health impacts. Exposure to tropospheric ozone (a key component of smog) in the short term (under one month) is considered causative of respiratory impacts (in particular asthma) which is responsible for a large share of emergency room visits. The commenter adds that, in the U.S. over 25 million people suffer from asthma. In the long term, ozone is also considered a likely cause of cardiovascular issues and respiratory mortality.

For example, commenter (0385-Silent Spring) notes that air pollutants, specifically those emitted by the oil and gas industry, are of concern for many human health endpoints including cancer. They note that, per EPA's analysis, it is expected that primary proposed NSPS OOOOb and EG OOOOc rules could reduce the combined emissions of VOCs by 12 million short tons and reduce emissions of HAPs by 0.48 million short tons between 2023 and 2035 alone.

Commenter (0385-Silent Spring and others) notes that VOCs are a primary precursor to tropospheric ozone (O<sub>3</sub>) pollution, which is already recognized by the EPA as a human health concern,<sup>46</sup> as research has classified ozone as a respiratory irritant<sup>47</sup> that contributes significantly to respiratory disease, asthma, congestive heart failure, and lung cancer.<sup>48</sup> In fact, the commenter reports that models estimate that respiratory-related deaths of 1.04–1.23 million adults worldwide are attributable to tropospheric ozone pollution.<sup>49</sup>

Moreover, the commenter (0385-Silent Spring and others) reports that VOCs are also a primary precursor to fine particulate matter, or PM<sub>2.5</sub>, which is also a profound respiratory irritant.<sup>50</sup> In 2011, the International Agency on Cancer Research (IARC) classified PM as a Group 1 carcinogen.<sup>51</sup> Research has well established statistically significant associations between

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<sup>46</sup> EPA. (2020). Health Effects of Ozone Pollution. Ground-level Ozone Pollution. <https://www.epa.gov/groundlevel-ozone-pollution/health-effects-ozone-pollution>.

<sup>47</sup> Filippidou, E. C., & Koukoulia, A. (2011). Ozone effects on the respiratory system. *Progress in Health Sciences*, 1(2). [https://www.umb.edu.pl/photo/pliki/progress-file/phs/phs\\_2011\\_2/144-155.pdf](https://www.umb.edu.pl/photo/pliki/progress-file/phs/phs_2011_2/144-155.pdf).

<sup>48</sup> Zhang, J., Wei, Y., & Fang, Z. (2019). Ozone Pollution: A Major Health Hazard Worldwide. *Frontiers in Immunology*, 10(2518). doi:10.3389/fimmu.2019.02518.

<sup>49</sup> Malley, C. S., Henze, D. K., Kuylenstierna, J. C. I., Vallack, H. W., Davila, Y., Anenberg, S. C., . . . Ashmore, M. R. (2017). Updated Global Estimates of Respiratory Mortality in ≥30 Years of Age Attributable to Long-Term Ozone Exposure. *Environmental health perspectives*, 125(8), 087021. doi:10.1289/EHP1390.

<sup>50</sup> Xing, Y. F., Xu, Y. H., Shi, M. H., & Lian, Y. X. (2016). The impact of PM<sub>2.5</sub> on the human respiratory system. *Journal of thoracic disease*, 8(1), E69–E74. doi:10.3978/j.issn.2072-1439.2016.01.19.

<sup>51</sup> Loomis, D., Grosse, Y., Lauby-Secretan, B., Ghissassi, F. E., Bouvard, V., Benbrahim-Tallaa, L., Straif, K. (2013). The carcinogenicity of outdoor air pollution. *The Lancet Oncology*, 14(13), 1262–1263. doi:10.1016/s1470-2045(13)70487-x.

particulate matter exposure and cancer,<sup>52,53,54</sup> respiratory disease,<sup>55</sup> cardiovascular disease,<sup>56,57</sup> and cerebrovascular disease. In fact, the commenter adds that research has modeled that daily mortality rates are expected to increase by 1.01% per 10µg/m<sup>3</sup> increase of PM<sub>2.5</sub> pollution,<sup>58</sup> directly exhibiting how significantly PM<sub>2.5</sub> pollution effects human health.

Commenter (0195-EEN) states that 2.9 million American children attend school within 0.5 radius of oil/gas facilities. The commenter states that, in Pennsylvania, at least 310,896 kids face this hazard.<sup>59,60,61</sup> The commenter notes that research by Dr. Shaina L. Stacy and others at the University of Pittsburgh found close proximity to unconventional gas wells in Butler County, PA is associated with babies born with lower birthweight.<sup>62</sup> Dr. Lisa M. McKenzie with the Colorado School of Public Health published peer reviewed research that links birth defects to methane production.<sup>63</sup> Research by Casey J.A., et al (2019) further describes that living within a

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<sup>52</sup> Raaschou-Nielsen, O., Andersen, Z. J., Beelen, R., Samoli, E., Stafoggia, M., Weinmayr, G., . . . Hoek, G. (2013). Air pollution and lung cancer incidence in 17 European cohorts: prospective analyses from the European Study of Cohorts for Air Pollution Effects (ESCAPE). *Lancet Oncol*, 14(9), 813-822. doi:10.1016/s1470-2045(13)70279-1.

<sup>53</sup> Krewski, D., Burnett, R., Jerrett, M., Pope, C. A., Rainham, D., Calle, E., . . . Thun, M. (2005). Mortality and long-term exposure to ambient air pollution: ongoing analyses based on the American Cancer Society cohort. *J Toxicol Environ Health A*, 68(13-14), 1093-1109. doi:10.1080/15287390590935941.

<sup>54</sup> Hamra, G. B., Guha, N., Cohen, A., Laden, F., Raaschou-Nielsen, O., Samet, J. M., . . . Loomis, D. (2014). Outdoor Particulate Matter Exposure and Lung Cancer: A Systematic Review and Meta-Analysis. *Environmental health perspectives*, 122(9), 906-911. doi:10.1289/ehp/1408092.

<sup>55</sup> Schwartz, J. (2002). Particulate Air Pollution and Chronic Respiratory Disease. *Environmental Research*, 62(1), 7-13. doi:10.1006/enrs.1993.1083.

<sup>56</sup> Hao, Y., Balluz, L., Strosnider, H., Wen, X. J., Li, C., & Qualters, J. R. (2015). Ozone, Fine Particulate Matter, and Chronic Lower Respiratory Disease Mortality in the United States. *American Journal of Respiratory and Critical Care Medicine*, 192(3), 337-341. doi:10.1164/rccm.201410-1852OC.

<sup>57</sup> Wang, J., Yin, Q., Tong, S., Ren, Z., Hu, M., & Zhang, H. (2017). Prolonged continuous exposure to high fine particulate matter associated with cardiovascular and respiratory disease mortality in Beijing, China. *Atmospheric Environment*, 168, 1-7. doi:10.1016/j.atmosenv.2017.08.060.

<sup>58</sup> Du, Y., Xu, X., Chu, M., Guo, Y., & Wang, J. (2016). Air particulate matter and cardiovascular disease: the epidemiological, biomedical and clinical evidence. *Journal of thoracic disease*, 8(1), E8-E19. doi: 10.3978/j.issn.2072-1439.2015.11.37.

<sup>59</sup> Achilleos, S., Kioumourtzoglou, M. A., Wu, C. D., Schwartz, J. D., Koutrakis, P., & Papatheodorou, S. I. (2017). Acute effects of fine particulate matter constituents on mortality: A systematic review and meta-regression analysis. *Environment international*, 109, 89-100. doi: 10.1016/j.envint.2017.09.010.

<sup>60</sup> <https://oilandgasthreatmap.com/threat-map/>

<sup>61</sup> Kazemiparkouhi, F., Eum, K.-D., Wang, B., Manjourides, J., & Suh, H. H. (2020). Long-term ozone exposures and cause-specific mortality in a US Medicare cohort. *Journal of Exposure Science & Environmental Epidemiology*, 30(4), 650-658. doi:10.1038/s41370-019-0135-4.

<sup>62</sup> 6 Nuvolone, D., Petri, D., & Voller, F. (2018). The effects of ozone on human health. *Environmental Science and Pollution Research*, 25(9), 8074-8088. doi:10.1007/s11356-017-9239-3.

<sup>63</sup> Stacy SL, Brink LL, Larkin JC, Sadovsky Y, Goldstein BD, Pitt BR, et al. (2015) Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania. *PLoS ONE* 10(6): e0126425. doi: 10.1371/journal.pone.0126425, downloaded September 28, 2015, <http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0126425>

<sup>64</sup> Lisa M. McKenzie, Ruixin Guo, Roxana Z. Witter, David A. Savitz, Lee S. Newman, and John L. Adgate, Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado, *Environmental Health Perspectives* doi:10.1289/ehp.1306722. downloaded September 28, 2015, <http://ehp.niehs.nih.gov/1306722/#tab3>

half-mile radius of natural gas development leads to increased brain, spine, or spinal cord birth defects.<sup>64</sup>

Commenter (0196-Meyaard-Schaap) states that methane pollution emitted alongside methane, such as benzene, exacerbates asthma and affects lung development in young children. The medical community has long known pollution and other environmental impacts harm unborn children. Studies show that smog, VOCs, and air toxics have a disproportionate impact upon life in the womb—from birth defects to low birth weight to increased brain, spine, or spinal cord malformation. All of it linked to proximity to methane infrastructure. Now is the time to address dangerous methane leaks from our oil and gas infrastructure, which at least one study has found leaks at a rate most likely 60% greater than current EPA estimates. Now is the time to ensure that the entire process of bringing oil and natural gas to market—from production to transportation to distribution—is free from unnecessary and wasteful leaking, venting, and flaring and is safe for every American.

Commenter (0215-EEN) states that it was once thought that unborn children were protected from pollutants, but medical research repeatedly shows that this is untrue. The exposure of expectant mothers, like myself only months ago, to air polluted with smog, VOCs, and air toxics from wasteful methane leaks during pregnancy puts their unborn children at increased risk for low birth weight<sup>65</sup> and birth defects<sup>66,67</sup>. The commenter notes that this is not a small or isolated problem - 2.9 million children attend a school located within with 0.5 miles of an oil/gas facility and 12.6 million Americans households are also within that radius.<sup>68</sup> Over 85% of the medical studies<sup>69</sup> that have studied the gas industry's impact on health find that that emissions from oil

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<sup>64</sup> Casey J.A., et al., "The association between natural gas well activity and specific congenital anomalies in Oklahoma, 1997-2009," *Environment International*, Volume 122, January 2019, 381-388, <https://www.sciencedirect.com/science/article/pii/S0160412018317999?via=ihub>

<sup>65</sup> Stacy SL, Brink LL, Larkin JC, Sadovsky Y, Goldstein BD, Pitt BR, et al. (2015) Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania. *PLoS ONE* 10(6): e0126425. doi:10.1371/journal.pone.0126425, downloaded September 28, 2015, <http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0126425>

<sup>66</sup> Lisa M. McKenzie, Ruixin Guo, Roxana Z. Witter, David A. Savitz, Lee S. Newman, and John L. Adgate, Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado, *Environmental Health Perspectives* doi:10.1289/ehp.1306722. downloaded September 28, 2015, <http://ehp.niehs.nih.gov/1306722/#tab3>

<sup>67</sup> Casey J.A., et al., "The association between natural gas well activity and specific congenital anomalies in Oklahoma, 1997-2009," *Environment International*, Volume 122, January 2019, 381-388, <https://www.sciencedirect.com/science/article/pii/S0160412018317999?via=ihub>

<sup>68</sup> <https://oilandgasthreatmap.com/>

<sup>69</sup> Hays J, Shonkoff SBC (2016) Toward an Understanding of the Environmental and Public Health Impacts of Unconventional Natural Gas Development: A Categorical Assessment of the Peer- Reviewed Scientific Literature, 2009-2015. *PLoS ONE* 11(4): e0154164. doi:10.1371/journal.pone.0154164

and gas facilities and infrastructure is highly detrimental to the health of both children and adults – this includes heart failure,<sup>70</sup> asthma,<sup>71</sup> and the exposure to known carcinogens.<sup>72</sup>

Combined, commenters state (0195-EEN, 0215-EEN) the two standards will save \$6.6 - \$9.2 billion in avoided health costs and loss of life.

Commenter (0351-Columbia) reports that they have been studying the health of populations living near oil and gas development since 2013. Their studies have used spatial methods and electronic health record data on thousands of individuals where we could control for both individual and area-level factors (Casey et al. 2016, Casey et al. 2018, Casey et al. 2019, Tustin et al. 2017, Rasmussen et al. 2016). They have found relationships between living closer to more wells and more actively producing wells and increased risk of preterm birth, migraine headache, depression, and cardiovascular disease in Pennsylvania. The commenter adds that, in studies in California with Dr. Rachel Morello-Frosch we have also used statewide birth certificate data and found that living within 1km of an oil or gas well was associated with increased odds of low birth weight, small for gestational age birth, and decreased term birth weight among individuals living in rural areas (Tran et al. 2020). They add that another study in Texas has found an increased risk of preterm birth among women exposed to gas flaring (Cushing et al. 2020).

Response I-20-3: We include an analysis of the impact of changes in VOC releases via their impact on ozone formation in chapters 3 and 4 of the final RIA. We are currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations, most notably the lack of sufficient emission location specificity to perform such analyses. The HAP impacts available in EPA's 2017 AirToxScreen dataset are provided for the entire oil and natural gas sector, which includes sources outside the scope of this regulation. We do not have current modeling of HAP impacts specific to only the sources subject to the regulation; therefore, we cannot estimate risks, including any reductions, solely attributed to the source category. Furthermore, more refined emissions data would be needed to conduct an assessment at the census block level, where we could draw more accurate conclusions about the human health risks.

Comment: In addition to requesting stronger regulation to mitigate emissions, many commenters (e.g., 0351-Columbia, 0421-Biosphere, 0559-Texas State Senator, 0216- Montana HPHC) request that EPA end or minimize routine flaring from oil and gas facilities. Commenter (0351-Columbia) states that this is because studies have shown that incomplete combustion during

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<sup>70</sup> McAlexander TP, Bandeen-Roche K, Buckley JP, Pollak J, Michos ED, McEvoy JW, Schwartz BS. Unconventional Natural Gas Development and Hospitalization for Heart Failure in Pennsylvania. *J Am Coll Cardiol*. 2020 Dec 15;76(24):2862-2874. doi: 10.1016/j.jacc.2020.10.023. PMID: 33303076; PMCID: PMC7735256.

<sup>71</sup> Rasmussen S.G., et al., "Association Between Unconventional Natural Gas Development in the Marcellus Shale and Asthma Exacerbations," *JAMA Internal Medicine*, 2016, 176(9), 1334–1343, <https://jamanetwork.com/journals/jamainternalmedicine/fullarticle/2534153> Willis, M. D., et al., "Unconventional natural gas development and pediatric asthma hospitalizations in Pennsylvania, *Environmental Research*, 166, 402-408, October 2018, <https://www.ncbi.nlm.nih.gov/pubmed/29936288>

<sup>72</sup> McKenzie, L.M., et al., "Ambient Nonmethane Hydrocarbon Levels Along Colorado's Northern Front Range: Acute and Chronic Health Risks," *Environmental Science Technology*, April 17, 2018, 52(8):4514-4525, <https://pubs.acs.org/doi/10.1021/acs.est.7b05983>

flaring can lead to emissions of volatile organic compounds, polycyclic aromatic hydrocarbons, carbon monoxide, nitrogen oxides, heavy metals, and black carbon. According to the commenter, the Cushing et al study from 2020 also found links between flaring exposure and adverse birth outcomes.

Commenter (0559-Texas State Senator) states that flaring often releases additional pollutants such as sulfur dioxide, ammonia, or VOCs.<sup>73</sup> Some of these compounds, such as benzene are known carcinogens.<sup>74</sup> Toluene is a neurotoxin that can cause miscarriages and birth defects. One recently published study examining the Eagle Ford Shale region found that “pregnant women who lived near areas where flaring is common had 50 percent greater odds of giving birth prematurely than those who did not.”<sup>75</sup> Beyond the human suffering itself, these health effects have an estimated economic impact of \$13-29 billion each year.<sup>76</sup>

Response I-20-4: We are currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations, most notably the lack of sufficient emission location specificity to perform such analyses. The HAP impacts available in EPA’s 2017 AirToxScreen dataset are provided for the entire oil and natural gas sector, which includes sources outside the scope of this regulation. We do not have current modeling of HAP impacts specific to only the sources subject to the regulation; therefore, we cannot estimate risks, including any reductions, solely attributed to the source category.

## **20.2 Regulatory Impacts Analyses (RIA)**

### **20.2.1 Cost-Benefit Analysis**

Comment: Commenter (0842-NYU School of Law) suggests that EPA note that its proposed standards for each source type within the category are net beneficial. The 2021 November RIA makes unambiguously clear that its proposed standards for new and existing sources, overall, are net beneficial. The commenter adds, however, that the EPA further disaggregate its analysis to show that, in addition to the entire proposal taken as a whole, each individual proposed policy change is net beneficial. For example, the commenter recommends that the EPA report net benefits for proposed standards for each type of regulated source—e.g., net benefits for the statutory best system of emission reduction (BSER) that applies to well sites, to gathering and boosting stations, and so on. According to the commenter, the EPA has the data needed to perform such calculations. The commenter notes that extending its analysis in this way would demonstrate that, in addition to a net beneficial set of proposed standards, each individual proposed standard is net beneficial and therefore creates value for society.

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<sup>73</sup> Alliance of Nurses for Healthy Environments, “Methane and Health”, 2017, <https://envirn.org/wpcontent/uploads/2017/08/Methane-and-Health-Factsheet.pdf>

<sup>74</sup> American Cancer Society, “Benzene and cancer risk”, 2017, <https://www.cancer.org/cancer/cancercauses/benzene.html>

<sup>75</sup> New York Times, “Study Links Gas Flares to Preterm Births, With Hispanic Women at High Risk”, Jul 22, 2020, <https://www.nytimes.com/2020/07/22/climate/gas-flares-premature-babies.html>

<sup>76</sup> Natural Resources Defense Council, “Methane Leaks from Oil & Gas Exploration: A Health Nightmare”, Dec 4, 2018, <https://www.nrdc.org/experts/vijay-limaye/methane-leaks-oil-gas-exploration-health-nightmare>

Likewise, the commenter (0842-NYU School of Law) suggests that the EPA also disaggregate the net benefits of each alternative standard. The 2021 November RIA reports the net benefits of its primary set of BSER standards, along with less stringent and more stringent standards, and a co-proposal. This information confirms that the primary proposal carries the highest net benefits of any alternative. But it does not show whether more stringent standards could carry higher net benefits within one or more source types. Without a more granular analysis, the commenter contends that the public cannot know whether the EPA's primary proposal would forego some net benefits for individual BSERs. The commenter recommends that, if the EPA does find such opportunities for higher net benefits for some BSERs, it should pursue them, or at least explain rigorously why it declines to do so.

Response I-20-5: In Table 5-6 of the Final Rule RIA, the EPA provides source-level information on estimated climate benefits and compliance costs of the finalized rule. In the interest of parsimonious presentation of results, however, the EPA does not present source-level estimates for the alternative scenarios assessed for the RIA, though the modeling scripts and data relied upon to generate those tables are available in the docket.

With respect to the commenter's suggestion regarding the use of source-level net benefit analysis in the RIA, the EPA notes that the EPA's standard-setting duties and authority are derived under section 111 of the CAA, and its decisions on emissions standards are made within the confines of that authority. Under the language of the statute, the EPA must consider the costs of control (as well as energy requirements and nonair quality health, and environmental impacts). The EPA has done so here. The monetized benefits analysis in the RIA prepared under Executive Order 12866 is entirely distinct from the statutory BSER determinations and are presented solely for the purposes of complying with E.O. 12866.

Comment: Commenter (0842- NYU School of Law) suggests that the EPA consider expanding and strengthening its cost-benefit analysis. Specifically, the commenter recommends that the EPA extend the timeframe of its analysis rather than assuming zero benefits past 2035. In addition, the commenter suggests that the EPA consider quantifying co-benefits from reducing non-methane VOC, PM, and HAP (see section 20.2.4 for further comment on quantifying co-benefits from reducing other non-methane pollutants). Finally, the commenter suggests that the EPA consider disaggregating costs and benefits by source type to demonstrate that its proposed standards and guidelines are individually, as well as cumulatively, net beneficial.

The commenter (0842- NYU School of Law) also recommends that the EPA expand its distributional analysis to evaluate the impacts of the 2021 November proposed rule and alternatives. In addition to baseline conditions, the commenter recommends that EPA also analyze the distributional impacts of its proposed standards and alternatives to evaluate the relative distributional impacts of its available regulatory options.

Response I-20-6: The EPA has addressed several of the commenter's points in the Final Rule RIA. First, the EPA extended the analysis horizon beyond 2035 to 2038 but declined to extend the analysis further due to the significant uncertainties in projected long-run sectoral trends. In addition, the EPA notes that the monetized climate benefits associated with the 2023-2038 CH<sub>4</sub> emission reductions reflects the discounted stream of benefits resulting from those emission

reductions over a much longer time horizon (out to 2300). Second, the EPA has added the quantification of the impact of changes in VOC releases via their impact on ozone formation in the Final RIA. However, the EPA is currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations (see Response I-20-3 for more information). Third, the EPA provides source-level information on estimated climate benefits and compliance costs in Table 5-6 of the Final RIA. Finally, in response to the commenter's suggestion regarding distributional analysis, the EPA expanded its distributional environmental justice analysis for ozone to include the estimated distributional impacts from the policy option in addition to baseline conditions. However, the EPA is unable to perform similar analysis regarding HAP emissions (see Response I-20-4 for more information).

Comment: Commenter (0793-PBPA) suggests that the EPA erred in its analysis when it compared current industry capital expenditures to capital expenditures under the proposed rule. Ultimately, the commenter states that the EPA concluded that capital expenditures under the proposed rule would only increase 0.3% when compared to the current capital expenditures.<sup>77</sup> According to the commenter, because operations within the oil and gas industry are so varied, many companies and segments of operations spend little to no capital annually. Most capital spent by the industry is in new drilling and completion of wells. The commenter concludes that the EPA's analysis is overbroad and should be refined to look at actual segments and types of operations rather than a one-size-fits-all approach applied to hundreds of thousands of sites.

Response I-20-7: While the EPA acknowledges the limitations of comparing estimated capital expenditures resulting from the regulation to overall industry-wide capital expenditures, it is not aware of existing data that could be used for the more disaggregated analysis that the commenter suggests. Moreover, while the commenter claims that many companies and segments of the oil and gas industry spend little to no capital annually, no specific information to support those claims was provided.

Though it was unable to perform a more disaggregated capital cost analysis, for the Final RIA, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry.

### ***20.2.2 Global Warming Potential (GWP) of Methane***

Comment: Commenter (0577-KIOGA) indicates that they find it disconcerting that the EPA references conflicting GWP for methane (80, 30, 29.8, 27.2, and 5) throughout the proposal instead of using the established GWP used for emissions inventory purposes.

Commenter (0585-KOGA) provides that, according to a White Paper published by two distinguished atmospheric physicists W. A. van Wijngaarden of York University, Canada, and W. Happer of the Princeton University Department of Physics, "methane contributes only about 30/300 or 1/10 of the already small warming from CO<sub>2</sub>". In their White Paper, the commenter

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<sup>77</sup> 86 Fed. Reg. at 63,157

reports that they provide calculations demonstrating the small impact of methane emissions on the environment as a basis that methane emissions should not be regulated due to potential global warming potential. According to the commenter, while many comments have been submitted to the EPA that recite the same talking points about methane's GWP, Wijngaarden and Happer provide the calculations to demonstrate the small impact that methane has on the atmosphere.

Commenter (0585-KOGA) adds that Wijngaarden and Happer note that for current concentrations of GHGs, methane has about 30 times greater impact than CO<sub>2</sub>. They also note that the addition of CO<sub>2</sub> to the atmosphere is about 300 times greater than the rate of increase of methane to the atmosphere. With the small rate of methane being added to the atmosphere, the calculated increase in global temperature is 0.012 degrees C/year. According to the commenter, with an impact this small, they believe that the EPA should focus efforts in other areas that provide a better cost/benefit ratio.

Commenter (0597-IN OGA) notes that, according to a White Paper published by two atmospheric physicists W. A. van Wijngaarden of York University, Canada, and W. Happer of the Princeton University Department of Physics, "methane contributes only about 30/300 or 1/10 of the already small warming from CO<sub>2</sub>". The commenter states that the White Paper provides calculations demonstrating the small impact of methane emissions on the environment as a basis that methane emissions should not be regulated due to potential global warming potential. The commenter asserts that, while many comments have been submitted to EPA that recite the same talking points about methane's global warming potential, Wijngaarden and Happer provide the calculations to demonstrate the small impact that methane has on the atmosphere.

Commenter (0428-Kfrost) asks EPA to prevent methane from being reported as CO<sub>2</sub>e from oil and natural gas sources. Please require all agencies to first identify actual methane emissions as methane emissions. Let's not have any source or agency providing methane as CO<sub>2</sub>e. No agency is using the CO<sub>2</sub>e correctly to identify potency of methane. To identify 2019 methane emissions as CO<sub>2</sub>e 100-year potency is just wrong and false. CO<sub>2</sub>e should only be used by scientists presenting current or future methane load analysis and use potencies corresponding to each year of emissions evaluated. For emissions 3 years ago, use the methane potency of 102 times carbon dioxide; and for emissions this year, use the potency of 120 times carbon dioxide. That is the proper use of carbon dioxide potency equivalency.

Commenter (0420-Kfrost) states that the Global Warming Potency for methane starts at 120 times carbon dioxide (CO<sub>2</sub>) in potency for the first year and the potency decreases over time ([https://www.researchgate.net/figure/Global-warming-potentials-for-methane-kgCO<sub>2</sub>-emissions-equivalent-to-a-kg-of-methane\\_fig2\\_263283839](https://www.researchgate.net/figure/Global-warming-potentials-for-methane-kgCO2-emissions-equivalent-to-a-kg-of-methane_fig2_263283839)). The commenter contends that, to represent all years regardless of how recent or how long ago, reported as all CO<sub>2</sub>e in multiples times 25 CO<sub>2</sub> for the 100-year potency is misrepresentative. The commenter suggests that it enables natural gas facilities to hide methane emissions into a 100-year equivalent of CO<sub>2</sub> in terms of past and future potential emissions rather than reporting actual methane emissions. The commenter adds that it creates a flawed notion of CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) of methane potency that is not true. They note: 2019 methane emissions do not currently have the potency of 25, in fact, the potency of 25 times CO<sub>2</sub> for 2019 emissions would occur in 2119.



Commenter (0795-Allergy and Asthma Network) requests that EPA acknowledge the extreme potency of methane's contribution to climate change by referencing its climate impact over a 20-year timeframe. The commenter notes that it is true that after 100 years in the atmosphere, methane "traps about 30 times as much heat as carbon dioxide," as EPA says in their November 2, 2021 press release about the 2021 November proposed rule.<sup>78</sup> However, they contend that grossly underestimates methane's impacts in the all-important next few years. According to the commenter, the timeframe that is truly relevant is the 20-year timeframe – roughly the timeframe available to us to head off catastrophic climate change impacts. The commenter states that utilizing this more relevant time frame is necessary to convey to the American people the true urgency of reducing methane emissions.

Commenters (0449-Public Employees, 0454-Kayrros) support the use of the 20-year GWP of methane rather than the 100-year GWP and agree with the EPA's stated reasoning. Commenter (0454-Kayrros) notes that the EPA estimates the social cost of methane at approximately \$1,800/ton but they believe that, given the 20-year GWP is more appropriate than the 100-year GWP, calculations of the social cost of methane should also be based on the 20-year GWP.

Commenter (0449-Public Employees) notes that the 2021 November proposed standards acknowledge the higher 20-year GWP, but the 2021 November RIA calculates methane's climate impact only using the 100-year GWP.<sup>79</sup> As the commenter explains below, the commenter recommends that the 2021 November RIA also calculate its impact using a 20-year GWP.

The commenter (0449-Public Employees) states that the EPA explains that its decision to use a 100-year GWP is "in accordance with the practice of the EPA [GHG Inventory], the EPA [GHG Reporting Program], and international reporting standards under the UN Framework Convention on Climate Change." However, the commenter states that the EPA does not specify why those programs' using a 100-year GWP preclude it from using the 20-year GWP here. The commenter contends that this lack of explanation is troubling, given the growing body of scientific evidence that favors using a 20-year GWP when crafting methane regulations. According to the commenter, several climate "tipping points" either have been triggered or will be in a matter of decades, not centuries. The IPCC sees a high probability of methane release from permafrost thaw in the 21st century.<sup>80</sup> The commenter adds that scientists have also found evidence that other tipping points, such as collapse of the Antarctic ice sheets or dieback of the Amazon rain forest, are fast approaching or already under way.<sup>81</sup> The commenter stresses that this situation demands that EPA regulate the short-term impact of GHGs.

Commenter (0449-Public Employees) states that scientists are beginning to recognize that the 100-year GWP, on its own, is ill-suited for this purpose. They provide that a 2020 paper observed that "there was no clear reason for [the Intergovernmental Panel on Climate Change]

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<sup>78</sup> U.S. EPA. U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health. Retrieved from <https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health>.

<sup>79</sup> See Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Docket Nos. EPA-452/R21-003, Regulatory Impact Analysis, (October 2021), Document ID No. EPA-HQ-OAR-2021-0317- 0173, at 2-38, 1-10, 2-30, 5-2, 3-2.

<sup>80</sup> IPCC, AR6 Climate Change 2021: The Physical Science Basis (2021), <https://www.ipcc.ch/report/ar6/wg1/>, 5-79.

<sup>81</sup> Timothy M. Lenton et al, Climate Tipping Points – Too Risky to Bet Against, 575 NATURE 592 (2019).

using this [100-year] value rather than 20 years or 500 years, and more recently the IPCC has stated the 100-year time period is arbitrary.”<sup>82</sup> They add that other recent peer-reviewed papers have argued that policymakers should use the 20-year GWP alongside the 100-year GWP.<sup>83</sup>

Commenter (0449-Public Employees) provides that some policymakers are already using the 20-year GWP. In 2019, New York lawmakers required the state’s Department of Environmental Conservation to use this value in preparing its annual Statewide Greenhouse Gas Emissions Report.<sup>84</sup> Internationally, a report prepared for the UN Framework Convention on Climate Change (UNFCCC) incorporated the 20-year GWP into its recommendations for reducing methane emissions from the oil and gas sector.<sup>85</sup> The commenter notes that EPA had claimed that given that some programs use the 100-year GWP they are precluded from adopting the 20-year one. According to the commenter, New York and the UNFCCC’s efforts suggest that the 20-year GWP can nonetheless be incorporated into climate policy.

Commenter (0449-Public Employees) states that the White House Office of Management and Budget (OMB) recognized this possibility during development of the Proposed Standards. Its comments on the rule’s 2021 November RIA noted that “the discussion of short vs. long lived (sic) gases could benefit from explicit use/discussion of the 20-year GWP.”<sup>86</sup> The commenter adds that OMB further noted that “the [Proposed Standards’] preamble has a good exploration of why it’s relevant that we’re dealing with a [short-lived climate pollutant] but [the RIA] never completes the thought by mentioning or applying the 20-year value. The commenter suggests that it is very easy to just add a column to a table showing a second CO<sub>2</sub>e estimate using the 20-year one while stressing that the 100-year one is the central estimate per US and international protocols.” The commenter notes that the EPA left the “Response” section to this comment blank.<sup>87</sup> The commenter reports that they have filed a Freedom of Information Act request for more information about why it used the 100-year global warming potential in these documents, but as of this writing it has not been completed. The commenter requests that EPA provide a response to OMB’s inquiry when it publishes the final Performance Standards.

In addition, commenter (0449-Public Employees) suggests, for the reasons described above, that EPA publish a RIA updated with the following information: Tables 1-3, 2-6, 2-11, 3-2, and 5- with an additional column for methane CO<sub>2</sub>e emission reductions calculated using methane’s 20-year GWP of 81. If any of these requested changes are impractical, the commenter asks that EPA

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<sup>82</sup> Robert W. Howarth, Methane Emissions from Fossil Fuels: Exploring Recent Changes in Greenhouse Gas Reporting Requirements for the State of New York, 17 *Journal of Integrative Environmental Sciences* 69, 71 (2020).  
<sup>83</sup> See Lukas P. Fesenfelt et al, Climate Policy for Short- and Long-Lived Pollutants, 8 *Nature Climate Change* 933 (2018) and Ilissa B. Ocko et al, Unmask Temporal Trade-Offs in Climate Policy Debates, 356 *Science* 492 (May 5, 2017).

<sup>84</sup> Howarth, Methane Emissions from Fossil Fuels at 69.

<sup>85</sup> Kate Larsen et al, Untapped Potential: Reducing Global Methane Emissions from Oil and Natural Gas Systems (2013), [https://www.globalmethane.org/documents/Untapped\\_Potential\\_Reducing\\_Global\\_Methane\\_Emissions\\_Oil\\_Natural\\_Gas\\_Systems\\_ENG\\_April\\_2015.pdf](https://www.globalmethane.org/documents/Untapped_Potential_Reducing_Global_Methane_Emissions_Oil_Natural_Gas_Systems_ENG_April_2015.pdf).

<sup>86</sup> Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Docket Nos. EPA-452/R21-003, Interagency Comment 2060-AV15 AND 2060-AV16 EPA Response, (October 18, 2021), Document ID No. EPA-HQ-OAR-2021-0317-0125.

<sup>87</sup> *Id.*

explain why, and not simply cite other reporting programs that use the 100-year GWP. By providing this information, the commenter believes that the EPA will ensure that scientists and the American public can evaluate the Performance Standards' effectiveness in addressing climate change.

Response I-20-8: Commenters (0585-KOGA and 0597-IN OGA) reference an article by Wijngaarden and Happer. As far as EPA is aware, this article has not gone through any peer review process. While the article presents an analysis of radiative influence that is consistent with scientific assessments (e.g., an influence of methane that is about 30 times the influence of CO<sub>2</sub> per molecule), the article's conclusions rely in large part on an extrapolation of concentration trends, rather than an analysis of the impacts of emissions of methane or CO<sub>2</sub>. Because of the short lifetime of methane, if methane emissions were to stop, then the concentration of methane would fall. Therefore, looking only at the increase of methane concentrations from year to year does not account for the full impact of methane emissions, a large part of which go to just keeping up with methane destruction. A better approach to attributing warming to different gases was done by the IPCC: see figure SPM.2 in the IPCC AR6 WGI Summary for Policymakers<sup>88</sup> which shows that human emissions of methane have contributed to about a third of the current warming due to human emissions of greenhouse gases (which, in total, contribute to more warming than has been observed, because they are partly offset by human emissions of cooling aerosols).

Moreover, the article does not make any attempt to actually determine the impacts on human health or welfare resulting from these emissions. Therefore, the article has not performed an analysis that is appropriate for making conclusions regarding the net costs and benefits of methane reductions.

Numerous commenters have suggested that EPA should use the 20-year GWP to value methane. However, only looking at relative impacts over the next 20 years is an incomplete comparison of methane and CO<sub>2</sub> impacts. The 100-year GWP value is more consistent with temporal valuation used elsewhere in US government cost benefit analyses. See, e.g., Sarofim and Giordano (2018, <https://esd.copernicus.org/articles/9/1013/2018/>) and Mallapragada and Mignone (2020, <https://link.springer.com/article/10.1007/s10584-019-02486-7>) which show that the 100-year GWP is equivalent to valuing future impacts with discount rate of about 3%, which is also the OMB Circular A-4 (2003) recommended discount rate for social goods.<sup>89</sup> A 20-year GWP would be equivalent to valuing future impacts at a much higher discount rate, which is inconsistent with how EPA (and many others) recommend valuing future damages and damages avoided. A 20-year GWP is not a good solution for avoiding tipping points: because it is a relative measure, using a 20-year GWP would lead to increased CO<sub>2</sub> emissions to balance reduced CH<sub>4</sub> emissions,

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<sup>88</sup> Figure SPM.2 in IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, pp. 3–32, doi: 10.1017/9781009157896.001 .]

<sup>89</sup> OMB Circular A-4 (2023) recommended a discount rate of 2.0% for such goods, which would be even less consistent with a 20-year GWP.

which would reduce the probability of near-term tipping point exceedances at the cost of increasing the probability of passing tipping points in the longer term.

### **20.2.3 Social Cost of Methane**

#### 20.2.3.1 IWG Recommended Interim SC-GHG Estimates

##### *General*

Comment: Commenter (0828-UCS) states that as it currently stands, the proposed rule is estimated to result in methane emission reductions on the order of 41 million short tons by 2035. Importantly, these estimates rely on an interim social cost of methane (SC-CH<sub>4</sub> or SCM), as re-established in February 2021 following Executive Order (EO) 13990. As these values are updated by the Interagency Working Group (IWG) to reflect the latest science and economics, the EPA should be sure to adjust its analyses accordingly.

Commenter (0423-RFF) describes the current RFF Social Cost of Carbon (SCC) initiative status. According to the commenter, the SCC initiative was established in 2017 as a multi-institutional, collaborative effort between Resources for the Future (RFF) and the University of California-Berkeley, with additional contributors from Duke University, Harvard University, Princeton University, and the University of Washington, among others. The commenter reports that the initiative has now completed the necessary research and implemented the near-term National Academies of Science, Engineering and Medicine (NASEM) recommendations to improve the scientific basis and transparency of the SC-GHG estimates across the full estimation methodology. The commenter reports that the initiative addresses:

- *Modularization of SC-GHG estimation methodology.* The commenter states that they have accomplished the modularization of the SC-GHG estimation process and corresponding improvement of transparency of the estimates through the provision of a new open-source software framework (Mimi.jl) for building integrated assessment models (IAMs). MMimi.jl has been utilized by the EPA in its RIA for the *Final Rule - Phasedown of Hydrofluorocarbons: Establishing the Allowance Allocation and Trading Program under the AIM Act*.
- *Long-run socioeconomic projections.* The commenter has used a combination of statistical information and expert judgement to generate long-run socioeconomic projections, with associated uncertainty bounds, of global emissions and regional economic growth and population that account for future politics and dependencies between the variables. This work, detailed here, has completed scientific peer review and is forthcoming in the Brookings Papers on Economic Activity (Rennert et. al).
- *Improved climate model.* The commenter notes that they have implemented the Finite Amplitude Impulse Response (FAIR, Smith et al. 2008) model highlighted in the NASEM report as used in the Intergovernmental Panel on Climate Change Sixth Assessment Report (Forster et al. 2021)
- *Updated damage functions.* We have implemented updated damage functions, which relate changes to the climate to economic impacts values in dollars, for key sectors based on the latest peer-reviewed scientific literature.

- *Economic discounting.* We have developed and implemented a methodology for empirically calibrating the key discounting parameters required for implementing NASEM recommendations to link discounting with uncertain economic growth projections, while also reflecting the empirical literature on the term structure of interest rates and being consistent with near-term rates associated with related federal discounting guidance. The methodology described here has completed peer-review and is forthcoming in the Journal of the Association of Environmental and Resource Economists.

The commenter (0423-RFF) notes that they have assembled these elements, each of which has undergone its own scientific peer review, into a new IAM on the Mimi platform that is responsive to the near-term recommendations of the NASEM report. They add that the updated estimates of the SC-CH<sub>4</sub> based on this new model are expected to be substantially higher than those employed in the 2021 November RIA for this proposed action. They conclude by reporting that the updated model and estimates are anticipated to complete peer-review in a timeframe relevant for consideration by the EPA as it finalizes the rule.

Response I-20-9: In response to comment, EPA has incorporated the use of the models developed under the RFF/Berkeley Social Cost of Carbon Initiative in the Final RIA. See the EPA's *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* that is included as Supplementary Material to the Final RIA for more details. A detailed response to comments pertaining to EPA's November 2022 draft of this report can be found in the Appendix of this RTC.

Comment: Commenter (0808-API) recommends that updates to the social cost estimates be considered with robust stakeholder engagement. As noted in their comments to OMB regarding the interim social cost estimates in June 2021, they believe that the actions taken thus far by the IWG do not reflect this administration's commitment to "public participation and an open exchange of ideas."<sup>90</sup> To date, the commenter reports that there has been only one opportunity for stakeholder engagement in the social cost estimate development process initiated by EO 13990 – one that amounted to a request for information not an opportunity to comment on the work undertaken by the IWG. They report that a recent brief filed by the DOJ suggests that stakeholders will have an opportunity to comment on the revised social cost estimates that the IWG will propose in spring of 2022. In its brief, the DOJ stated that the IWG will "publish its proposed final estimates within the next two months," and that the public will be given the opportunity to comment on these proposed estimates.<sup>91</sup> Further, the commenter states that the EPA has published a request for nominations to form a panel to provide an independent, scientific peer-review of the forthcoming estimates.<sup>92</sup> The commenter notes that the indication of both an independent, expert peer-review and a public notice and comment period is a welcome development. The commenter encourages the IWG to use the forthcoming opportunities to engage with stakeholders, address comments that are provided and seek further feedback. Along

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<sup>90</sup> Executive Order 13563, Improving Regulation and Regulatory Review (January 28, 2011), at Sec. 1(a). [https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/inforeg/inforeg/eo12866/eo13563\\_01182011.pdf](https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/inforeg/inforeg/eo12866/eo13563_01182011.pdf).

<sup>91</sup> Def. Supp. Br., 23, *La. v. Biden*, No. 2:21-cv-01074 (W.D. La. Jan. 21, 2022).

<sup>92</sup> On Tuesday, January 25th, the commenter notes that the EPA published a request for nominations of experts to act as reviewers of the proposed final estimates and the accompanying Technical Supporting Document (TSD). 87 Fed. Reg. 3801 (January 25, 2022)

these lines, they encourage EPA to submit for public comment a list of questions EPA is considering to guide the expert peer-review along with the list of candidates as outlined in the EPA request for nominations.<sup>93</sup> According to the commenter, these forthcoming engagements represent an opportunity for the IWG and EPA to improve their process.

Separately, the commenter (0808-API) reports that the DOJ brief also indicated that the IWG has not yet submitted recommendations for the use of the social cost estimates across federal decision-making. API encourages the IWG and the White House to publish those recommendations, in full, for public comment.

The commenter (0808-API) suggests that a failure to engage with stakeholders directly during the process or during a public comment period specifically to address the methodology of the estimates may jeopardize the durability of regulations dependent on this analysis. The commenter encourages EPA, as a member of the IWG, to direct the IWG to follow through on the administration's commitment to public participation by opening the process and engaging directly with stakeholders.

Given the timeline set by this administration, and the updated timeline for the proposal of revised social cost estimates, the commenter (0808-API) states that it is likely that the IWG will have proposed a revised set of social cost estimates for stakeholder review and comment prior to EPA issuing a supplemental proposal or a final rulemaking for methane emissions from the oil and natural gas sector. The commenter encourages EPA to complete a revised RIA including these new estimates and other factors as necessary before moving forward.

Response I-20-10: While EPA continues to participate in the work of the IWG under E.O. 13990, EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA identified numerous unique substantive public comment submissions to the docket that were relevant to the updated SC-GHG estimates. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates in the Appendix of this RTC. The EPA also conducted an external expert peer review of the External Review Draft of the SC-GHG Report consistent with the guidelines set forth in EPA's Peer Review Handbook 4th Edition, 2015. In addition to two opportunities for comment during the peer review selection process (described in the Appendix to this RTC), the public was also invited to attend the meeting of the peer review panel on March 29, 2023. The EPA posted the charge questions on the EPA webpage and provided public notice of the peer reviewer meeting 3 weeks in advance. Since the public comment period on the Supplemental Proposal closed on February 13, 2023, the public comments received on the Supplemental Proposal were also available to the peer reviewers as they conducted their review. Some peer reviewers even cited public comments in their final report. The EPA posted a recording of the public meeting on the

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<sup>93</sup> 87 Fed. Reg. 3803 (January 25, 2022)

webpage and posted the final peer review report following its completion in May 2023. Complete information about the external peer review, including the peer reviewer selection process, the charge questions and final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available at: <https://www.epa.gov/environmental-economics/scghg-tsd-peer-review>.

Regarding the IWG work conducted under E.O. 13990 to develop recommendations regarding areas of Federal Agency decision making for which SC-GHG may be applied, the EPA refers the commenter to the September 2023 White House announcement regarding the use of SC-GHG estimates in facilitating comparison of the climate consequences of alternative options in budgeting, procurement, and other agency decisions. See <https://www.whitehouse.gov/briefing-room/statements-releases/2023/09/21/fact-sheet-biden-harris-administration-announces-new-actions-to-reduce-greenhouse-gas-emissions-and-combat-the-climate-crisis/#:~:text=The%20President's%20Day%20One%20Executive,agencies%20should%20consider%20the%20Social>.

### *Support for Use of IWG Recommended Interim SC-GHG Estimates*

Comment: Commenters (0761-Excelon Corporation, 0844-EDF et al, 1267-CA) support the EPA's use of the interim SCM established in the IWG on Social Cost of Greenhouse Gases' recently published Technical Support Document (TSD) (2021 IWG TSD)<sup>94</sup> in evaluating the costs and benefits of the Proposed Rule.<sup>95</sup> The commenters believe that the EPA's 2021 November proposed rule RIA understates the benefits of its proposal. While the commenter supports the use of the IWG's February 2021 Social Cost of Methane (SC-CH<sub>4</sub>) and its global perspective, they contend that it understates the true cost of methane.

Commenter (0761-Excelon Corporation) agrees that EPA should use the social cost of methane, estimated by the IWG on SC-CH<sub>4</sub>, in the cost-benefit calculation for the Proposal. The commenter states that federal agencies should incorporate the social cost of GHGs in all relevant areas of decision making including regulatory analyses, and the social cost of methane is the appropriate value to use in conducting benefit-cost analyses and estimating the climate impacts of policies that affect methane emissions.

Commenter (0804-EDF et al) cautions EPA that it must defend against common criticisms of the IWG social cost valuation methodology (e.g., that claim that the IAMs)—the damage functions for translating climate impacts into economic losses—are flawed and arbitrary) and suggests responses in the text of their comment letter (see pages 34 and 35 of their comment letter), to common criticisms that have been offered by opponents.<sup>96</sup>

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<sup>94</sup> Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimate Under Executive Order 13,990 (Feb. 2021).

<sup>95</sup> See 86 Fed. Reg. at 63,122-23.

<sup>96</sup> William Nordhaus, An Optimal Transition Path for Controlling Greenhouse Gas Emissions, 258 SCIENCE 1315 (1992); Memorandum by Dr Chris Hope, Judge Institute of Management, University of Cambridge, (Jan. 14, 2005), <https://publications.parliament.uk/pa/ld200506/ldselect/ldconaf/12/5011805.htm>; *Ctr. for Biological Diversity v. NHTSA*, 538 F.3d 1172 (9th Cir. 2008); 2010 TSD, supra note 28; Interagency Working Group on the Social Cost of

Commenter (0844-EDF et al) provides that the SC-CH<sub>4</sub> measures the net economic harm to society due to climate change for every additional ton of methane emitted, or the economic value of avoiding those emissions. The SC-CH<sub>4</sub> is meant to encompass the value of all climate change impacts including human health effects, property damage, conflict, and changes to ecosystem services.<sup>97</sup> The SC-CH<sub>4</sub> is appropriate to use in cost-benefit analyses in the finalized rule. Because even the most accurate SC-CH<sub>4</sub> reflects the societal value of reducing methane emissions and represents net benefits to society, the commenter states that the SC-CH<sub>4</sub> is reasonable and is thus a useful measure in determining the cost-effectiveness of a rule. The commenter reports that the U.S. Government Accountability Office (GAO) reviewed the IWG's process and concluded that the IWG: (1) used consensus-based decision making; (2) relied largely on existing academic literature and models, including technical assistance from outside resources; and (3) took steps to disclose limitations and incorporate new information by considering public comments and revising the estimates as updated research became available.<sup>98</sup> Notably, the commenter adds that several court decisions recognize that the social cost of GHGs (SC-GHG) is a reliable and scientifically validated approach to monetizing climate change impacts that should be incorporated into federal decision-making. The commenter urges the agency in its final rule to use an updated SC-CH<sub>4</sub> that better reflects the true social cost of methane.<sup>99</sup> The commenter further states:

- The EPA's finalized rule should maintain a global perspective in its SC-CH<sub>4</sub> calculation because the IWG and the EPA have correctly recognized that methane is a global pollutant whose economic impacts can only be fully accounted for by considering its effects both within the U.S. and abroad. Furthermore, there is a national interest in encouraging other jurisdictions to fully account for the costs of climate pollution, which would be put at risk if the EPA were to focus solely on domestic costs.
- They agree with the EPA's recognition that the SCM must consider global, not just domestic, emissions. Economic principles suggest that the full costs to society of emissions should be considered to identify the policy that maximizes the net benefits to society, i.e., achieves an efficient outcome. Estimates of global benefits capture more of the full value to society than

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Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2013), <https://obamawhitehouse.archives.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbonfor-regulator-impact-analysis.pdf>; Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (2016), [https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc\\_tsd\\_final\\_clean\\_8\\_26\\_16.pdf](https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf) [hereinafter 2016 TSD]; Request for Comment, 78 Fed. Reg. 70,586 (Nov. 26, 2013); Response to Comments, *supra* note 29; Interagency Working Group on the Social Cost of Greenhouse Gases, Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (2016), [https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/august\\_2016\\_sc\\_ch4\\_sc\\_n2o\\_addendum\\_final\\_8\\_26\\_16.pdf](https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/august_2016_sc_ch4_sc_n2o_addendum_final_8_26_16.pdf).

<sup>97</sup> Proposal, 559.

<sup>98</sup> U.S. Gov't Accountability Off., Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates, at 8 (July 2014), available at <https://www.gao.gov/assets/gao-14-663.pdf>,

<sup>99</sup> Beyond the discussion here, many of the joint commenters have also signed onto a comment submitted by the Institute for Policy Integrity which discusses the legal issues associated with the social cost of methane in more depth



domestic estimates and can therefore help guide policies towards higher global net benefits for GHG reductions. The consideration of global impacts is also fully within the authority of federal agencies.

- The EPA was correct to abandon a 7% discount rate. While an even lower range of discount rates would be more appropriate, see *infra* subsection v, abandoning the 7% rate better aligns with what the expert consensus recommends for analyzing the impacts of a high-risk, long-term, multi-generational crisis such as global climate change. However, the EPA fails to present any valuation of the climate benefits using such lower discount rates. Conducting such evaluations should not be overly burdensome for the agency and will provide useful additional information on the benefits of the rule.
- The EPA has full legal authority to apply the IWG's approach to the SC-CH<sub>4</sub>. The commenter suggests that EPA take the opportunity to clarify in its final rule the legal authority that supports its use of a global perspective and range of lower discount rates. The agency should first highlight the multitude of authorities that allow and support the use of a global calculation. For example, the National Environmental Policy Act (NEPA) the United Nations Framework Convention on Climate Change, and *Zero Zone v. Department of Energy* (the Seventh Circuit upheld a Department of Energy (DOE) regulatory analysis). Further, the use of the social cost of SC-GHG in evaluating the costs and benefits of a commenter states that the proposed rule has been upheld by courts and does not violate the major questions or any other legal doctrine.
- The EPA recognizes that the interim SC-GHG likely underestimates the true cost of methane pollution. Although the IWG's 2021 SC-CH<sub>4</sub> is the best and most representative set of estimates for the social cost of methane that the federal government has thus far produced, numerous experts, including the EPA itself (see 2021 November proposed rule RIA 3-13), agree that all currently available estimates of social cost of GHGs (including the IWG's SC-CH<sub>4</sub>) are likely still too low.<sup>100</sup> Proposed areas for revision include decreasing the discount rate to further account for the welfare of future generations, improving economic damage estimates, and updating the underlying climate science. For certain policy decisions, non-climate health impacts, such as methane damages to human health via ozone formation, should also be included. The SC-CH<sub>4</sub> does not incorporate non-climate impacts on local health. Recent epidemiologically derived research suggests that such non-climate impacts from methane may be significant. Methane-induced changes in surface ozone affect air quality, human health, and agricultural productivity in ways that have significant costs. The Sarofim et al. (2015)<sup>101</sup> and Shindell (2015)<sup>102</sup> studies aim to extend the methodology underlying the IWG SC-CH<sub>4</sub>, resulting in cost ranges that would be much higher than current values. The EPA and the IWG agree that, taken together, these features suggest that the interim SCM estimates used in this proposed rule likely underestimate the damages from methane.<sup>103</sup> According to another commenter (1267-CA), although the EPA has recognized

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<sup>100</sup> Wagner, G., Anthoff, D., Cropper, M., Dietz, S., Gillingham, K. T., Groom, B., Kelleher, J. P., Moore, F. C., & Stock, J. H. (2021). Eight priorities for calculating the social cost of carbon. *Nature*, 590(7847), 548–550. <https://doi.org/10.1038/d41586-021-00441-0>

<sup>101</sup> Sarofim Marcus C., Waldhoff Stephanie T. and Anenberg Susan C. "Valuing the Ozone-Related Health Benefits of Methane Emission Controls." *Environ Resource Econ* (2015).

<sup>102</sup> Shindell, Drew T. "The social cost of atmospheric release." *Climatic Change* (2015): 130:313–326

<sup>103</sup> 2021 November Proposed Rule RIA 3-13.

these limitations, the commenter states that the EPA should improve its disclosure and evaluation of those limitations.

- The EPA has also recognized several areas of damages that are not quantified in the models including ecosystems, increased fire risk and wildfires, sea level rise and storm surges, pests and pathogens and catastrophic impacts, and loss of cultural heritage, and favored landscapes.

Response I-20-11: The EPA acknowledges the comments. As mentioned in the previous response, the EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates in the Appendix of this RTC.

Comment: Commenter (0936-U.S. House of Representatives) states that the rule's current legally required cost-benefit analysis makes two questionable assumptions:

1. It assumes a discount rate of only 3 percent.<sup>104</sup> With the recent spike in inflation for the U.S. economy hitting 40-year highs of 6.8 percent<sup>105</sup>, it is vital to choose the steps we follow wisely and efficiently. Pursuing any other path will potentially hamper future natural gas.
2. Producer prices are currently running close to 10 percent, this peg at 3 percent is overly optimistic. Likewise, the EPA includes in its cost-benefit analysis a price for natural gas at \$3.13, which is the U.S. Energy Information Administration's prospective average price for 2022.

Commenter (0936-U.S. House of Representatives) asserts that given the rapid rise in energy prices over the past year and threats affecting future spikes, the accuracy of average price above is questionable. The commenter notes that the rule uses the IPCC as the exclusive source for many of its claims, including that the oceans are rising, hurricanes and storms are getting more severe, and that the last decade "might have been" the warmest in the last century.<sup>106</sup> A comparison of IPCC claims and other scientific opinions are necessary here. The EPA has used the IPCC as its single source to justify this rule with very alarmist language. According to the commenter, a nationwide ruling of vast scope and impact should include information and analysis from multiple independent sources before it is implemented.

Response I-20-12: It is assumed that the commenter is questioning assumptions used in BSER analyses conducted for NSPS OOOOb affected facilities and EG OOOOc designated facilities

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<sup>104</sup> EPA Regulatory Impact Analysis for the Proposed Standards of Performance, Page 1-11, January 31, 2022. [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0).

<sup>105</sup> Bureau Labor and Statistics, <https://www.bls.gov/opub/ted/2021/consumer-prices-up-6-8-percent-for-year-ended-november-2021.htm>, January 31, 2022.

<sup>106</sup> Regulatory Impact Analysis for the Proposed Standards of Performance, [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf). January 31, 2022.

and not the benefit cost analysis conducted under the December 2022 Supplemental Proposal RIA. With regards to the comment on the EPA's use of a discount rate of 3 percent in BSER analyses as being optimistic, the EPA agrees that it is optimistic in the short term due to increases in producer prices driven by external factors. However, the BSER analyses conducted for NSPS OOOOb affected facilities and EG OOOOc designated facilities use a discount rate of 7 percent (and sometimes 3 percent along with 7 percent) when estimating the capital recovery cost component of the annual cost of equipment considering the life of the equipment. The use of 7 percent is reasonable from a long-term perspective of 10 to 15 years, which is generally the number of years assumed for equipment life in analyses.

In response to comment that the EPA's assumption of a natural gas price at \$3.13/mcf (the average price for 2022) was not reasonable given the rapid rise in energy prices, the EPA disagrees. While the natural gas price may be volatile, from a long-term perspective, this estimate was and is reasonable to use in BSER analyses. It is important to note, however, that while the \$3.13/mcf<sup>107</sup> was used in differing BSER analyses to represent the price of natural gas when calculating the natural gas cost savings that would be associated with various regulatory options, the calculated gas savings estimates illustrate the benefits of varying regulatory options being considered but are not used as a sole determinant of what constitutes BSER. Notably, this offset does not apply where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.*, transmission stations and storage facilities).

Comment: Commenter (0808-API) recognizes the importance of including the potential impacts of climate change in the RIA. When performing a benefit-cost analysis as part of a RIA, the commenter notes that the EPA is justified in applying an estimate of the value of the impacts of a regulation to reduce GHGs. This is especially true in a regulation which has as its primary purpose the reduction of GHGs. As noted in OMB Circular A-4 (2003), the commenter states that monetization of as many impacts as possible, and especially those central to the regulation, is essential to a properly conducted benefit-cost analysis.<sup>108</sup> However, the commenter recommends that specific care be taken when using the social cost of methane estimates (SC-CH<sub>4</sub>) as an input to the RIA. Per the recommendations of the National Academies of Science, Engineering and Medicine (NASEM) in their 2017 review of the social cost of carbon estimates (SCC),<sup>109</sup> the commenter suggests that the social cost estimates be presented with a full discussion of the uncertainties associated with the development and presentation of those estimates. The commenter notes that the 2021 November proposed rule RIA describes some of the uncertainties well and includes a presentation of the frequency distributions used to generate the social cost estimates. However, according to the commenter, there are some issues that have not been addressed, including the inability to use a consistent set of socioeconomic and

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<sup>107</sup> This value reflects the forecasted Henry Hub price for 2022 from: U.S. Energy Information Administration. Short-Term Energy Outlook. <https://www.eia.gov/outlooks/steo/archives/may21.pdf>.

<sup>108</sup> Office of Management and Budget, Circular A-4 (September 17, 2003). <https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf>.

<sup>109</sup> National Academies of Sciences, Engineering, and Medicine. 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24651>.

emissions scenarios to generate both the social cost estimates and other benefits and costs associated with the regulation, and a consistent application of discount rates.

Response I-20-13: As mentioned in the previous response, EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates (including comments received from this same commenter (API) in the Appendix of this RTC.

### *Opposition for Use of IWG Recommended Interim SC-GHG Estimates*

Comment: Commenters (0910-AGKY, 0824-WDEQ) state that the Methane Notice relies extensively upon the SC-GHG estimates in analyzing the costs and benefits of the EPA's new approach. The commenters contend that these estimates are fundamentally flawed and at odds with the CAA.

Commenter (0910-AGKY) contends that, reliance on the SC-GHG estimates in any form would render any new rulemaking arbitrary and unlawful. Below is support that they provide for their contention:

- The IWG can point to no statutory authority whatsoever authorizing it to promulgate the SC-GHG. This is a major rule if there ever was one, so it can only be promulgated based on specific statutory authority and in compliance with the APA's processes. But the only statutory authorities addressing the issue expressly preclude consideration of global effects.
- The SC-GHG estimates break with decades of best regulatory practice; in particular, they jettison Circular A-4 (2003)'s domestic-effects focus and discount-rate range for no good reason.
- The estimates fail to account for significant state interests in cooperative federalism regimes and the harm they will cause to the States and their citizens.
- The IAMs underlying the SC-GHG estimates are inherently flawed and weighted toward a particular outcome.
- The Obama Administration's SCC estimates have been flawed from their inception. The administration rejected and ignored public comments on the underlying models and announced it would delay substantive revisions in response to public comment until the National Academy of Sciences (NAS) finalized its recommendations. But such substantive revisions were never made. Yet even the paltry public input the Administration allowed revealed fatal flaws in the Estimates and the underlying IAMs.
- The Obama Administration never clearly identified the statutory authority for the SC-GHG. Though a Ninth Circuit opinion prompted it to come up with some measure of costs from carbon, the Administration failed to look to the law to determine the scope of those costs.

Commenters suggest that, if the Administration had looked at the law, it would have noted Congress's consistent preclusion of the consideration of global benefits.

- Experts note the sheer arbitrariness of the IAMs underlying the SCC estimates. These models rest on a three-hundred-year time horizon, meaning they purport to predict political, technological, economic, social, and geopolitical developments three centuries into the future. Other commentors note the SCC estimates rest on flawed and arbitrary damage functions: "These damage functions translate variables, such as projected sea level rise, to estimated economic damages. By their nature, we know very little about the correct functional form of damage functions." In fact, the commenter notes that even the Obama Administration's DOE noted that the SCC was not ready for prime time but continued to implement it anyway. To Louisiana's knowledge, no other regulatory tool rests on such uncertainty and guesswork.
- The commenter notes the sheer uncertainty of the SCC estimate caused by the IWG's break with the Executive Branch's longstanding approach to discount rates. They contend that the IWG arbitrarily jettisoned the longstanding 7 percent discount rate and employed an entirely new spectrum going as low as 2.5 percent and even encouraging agencies to depart downward.
- The IWG's process fails key good-government transparency standards such as personnel involved and whether outside consultants participated. The commenter states that such failures violate longstanding OMB regulatory-integrity guidelines. They add that it appears that history is repeating itself in the present process.
- According to the commenter, the failings of the Obama IWG's enterprise can perhaps best be seen by recognizing the agencies that used the SCC estimates: only those that had to follow them used the SCC estimates. Traditionally independent agencies—who were not compelled to use the SCC estimates—recognized the estimates' flaws and chose not to use them.

Commenter (0910-AGKY) reports that the Biden Administration picked up where the Obama Administration left off in 2016. Per EO 13990, the IWG produced the SC-GHG estimates that are the subject of this comment period. According to the commenter, the SC-GHG estimates are inherently flawed for several independent reasons:

- The SC-GHG estimates ignore and contravene the law. The SC-GHG estimates are not authorized by, and directly conflict with, the law. Like the Obama IWG, the Biden IWG has not been able to point to statutory authorization for the SC-GHG estimates. This failure is particularly egregious given the national importance of the SC-GHG calculations. Yet the IWG cites no authority for its unprecedented approach to regulatory practice that will impose hundreds of billions or trillions of dollars in regulatory costs on the U.S. economy in future years and decades and fundamentally transform American life. If Congress wishes to authorize the President to implement sweeping new costs for GHGs—and test the limits of the nondelegation doctrine, the Commerce Clause, and the Tenth Amendment—it must do so clearly. The IWG's silence on statutory authority is deafening.
- The SC-GHG estimates' political, regulatory, and constitutional implications but were never subject to robust and independent notice and comment process. This meager comment period is not sufficient to cure this defect because agencies have already taken significant actions in reliance upon the 2021 SC-GHG Estimates. But the SC-GHG Estimates don't just exceed congressional authorization—they are specifically prohibited by several discrete statutes.

- First, as discussed above, the Estimates cannot be reconciled with the CAA. When Congress addresses global effects in the CAA, it does so through specific procedures outside of the domestic regulatory process, which remains focused exclusively on domestic effects.
- The estimates' global focus contravenes the Energy Policy and Conservation Act (EPCA). EPCA is structured to "increase domestic energy supplies and availability; to restrain energy demand; to prepare for energy emergencies; and for other purposes." EPCA's structure buttresses this domestic focus; it specifically authorizes the Secretary of Energy to consider international effects only in limited circumstances that have nothing to do with domestic regulation. When Congress wishes for agencies to consider international effects, it does so explicitly. It has not done so in EPCA, which retains its domestic-only focus.
- The National Environmental Policy Act's (NEPA) explicit domestic focus leaves no room for the SC-GHG Estimates' consideration of global effects. The Council on Environmental Quality's (CEQ) binding NEPA implementation regulations also preclude the SC-GHG's use of highly uncertain models to predict the effects of GHGs hundreds of years into the future. As CEQ's regulations instruct—and the Supreme Court has held—agencies must consider only effects that are "reasonably foreseeable" and bear a "reasonably close causal relationship" to the proposed action, "analogous to proximate cause in tort law." This proximate-cause standard is fundamentally at odds with the expansive approach embedded in the SC-GHG Estimates. But the IWG does not acknowledge the existence of CEQ's standard, or that it is compelling agencies to use a fundamentally different causation standard when calculating environmental effects for cost/benefit purposes than the standard they must use when calculating the same effects under NEPA.
- The SC-GHG Estimates are fundamentally incompatible with the Outer Continental Shelf Lands Act (OCSLA), which was enacted and then amended to "achieve national economic and energy policy goals, assure national security, reduce dependence on foreign sources, and maintain a favorable balance of payments in world trade." 43 U.S.C. §1802(1); By inevitably restricting the number of parcels that will be made available in OCSLA sales, and making it harder to obtain drilling permits, the Biden SC-GHG Estimates contravene the Secretary of the Interior's duty to make the Outer Continental Shelf "available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs.
- This systematic clash with statutory authority is particularly damaging due to EO 13990's mandatory command directing agencies to employ the SC-GHG Estimates. Indeed, agencies followed the Obama Administration's mandatory command rather than considering whether the IWG's values conflicted with statutory factors: Perhaps emboldened by [the IWG's] general dismissal of statutory constraints, agencies using the globally scoped SCC have appeared to ignore the question of statutory authority entirely. There is no reason to expect that agencies will respond differently to the Biden Administration's mandatory command.
- According to the commenter, the IWG's SC-GHG estimates represent an emphatic break from time-tested Executive Branch regulatory best practices. The Estimates first break best practice in that the IWG has never adequately justified its use of a global rather than domestic scope in calculating costs. And second, the IWG breaks from decades of Executive Branch practice regarding discount rates. The IWG fundamentally alters this longstanding practice without a reasoned justification. Circular A-4 (2003) explains that the 7 percent discount rate is essential to reasoned cost/benefit analysis.

- The SC-GHG estimates ignore the substantial reliance interests that have reasonably grown up around decades of regulatory practice. The Methane Notice ignores decades of specific reliance on the EPA's prior approach to regulating Methane. But the SC-GHG Estimates also ignore several other reliance interests. IWG ignores the significant federalism costs caused by the SC-GHG Estimates. Despite this clear directive, the IWG nowhere considers that the higher SC-GHG Estimates will encroach on the States' traditional police power. The SC-GHG Estimates fail to consider the muddled and conflicting standards and implementation costs imposed upon the States by its fundamental shift in methodology. For example, States must comply with federal standards in programs such as the National Ambient Air Quality Standards (NAAQS), 42 U.S.C. §7410. Because these NAAQS are now required to be set based on the IWG's SC-GHG Estimates, states must employ the estimates or their state implementation plans (SIP) will be disapproved. And if a SIP is disapproved by the EPA, the EPA must impose a federal implementation plan (FIP)—which must be based upon the SC-GHG Estimates—upon the State. This harm is far from speculative—the EPA has already published a final rule relying on the Biden SC-GHG Estimates to impose more stringent NAAQS good-neighbor FIPs on several Plaintiff states including Louisiana, Kentucky, and Texas.
- IWG neglected to consider the effects the SC-GHG estimates will have upon state revenue. states stand to lose millions immediately—and billions in the long run—in revenue because of the SC-GHG Estimates. This constitutes yet another important aspect of the problem that the IWG failed to recognize. As clear from the Methane Notice, States will also be required to shoulder increased regulatory costs. The States' economic well-being, statutorily conferred role in cooperative federalism programs, and reliance upon existing regulatory practices are important aspects of the problem. Yet the IWG acted as if the States do not exist.
- The commenter posits that the IAMs are irremediably flawed and fail to account for positive externalities. The IAMs themselves, and the process used to produce the Estimates from their disparate results, demonstrate the fundamental flaws. Some of the equations that go into IAMs— especially the damage functions and the long and unpredictable timeframes that are patently absurd and depart from best regulatory practice. As experts have explained, the models rest more on science fiction than the best available science.
- The estimates also fail to consider the positive externalities of energy production. The Working Group arbitrarily focused only upon energy production's negative aspects without considering the benefits affordable energy has on economic development, social welfare, economic and energy independence, and international peace. Instead, it continued to rely upon IAMs that arbitrarily refuse to consider potential benefits from a warming climate.
- Both the IWG and the underlying models also demonstrate their bias by systematically refusing to consider the economic and health benefits, indicating a determination to bend science to a particular policy outcome.
- The method by which IWG uses these flawed models is equally arbitrary. Each model produces different SC-GHG values. Instead of accounting for the relative flaws and strengths of each model, the Biden IWG (like the Obama IWG) simply averages the SC-GHG values produced by these models to reach the definitive SC-GHG Estimates that agencies must follow. The SC-GHG Estimates are a simple average of three flawed models—nothing more. It is hard to imagine a more arbitrary process.

According to the commenter (0910-AGKY), the entire SC-GHG is driven by out of date, arbitrary, and politically biased models that purport to know how human society will look in the year 2300.

Commenter (0824-WDEQ) states that the proposed rule's consideration of the social cost of methane is not in line with the actual costs that are associated with methane emission reductions. And, on the other side of the cost benefit analysis, the proposed rule would have immense economic impacts upon Wyoming's economy that simply are not considered quantitatively or qualitatively in the 2021 November proposal RIA. Oil and gas severance taxes and royalties contribute funding to state highway and county road construction and maintenance; water projects; local governments; school districts, scholarships, and the University of Wyoming and community colleges; and state-government agencies. Combined, oil and natural gas brought in more than \$372,000,000 in severance taxes for the state coffers during fiscal year 2021.<sup>110</sup> This also extends to the direct and indirect employment of tens of thousands of workers. In 2019, when Wyoming oil production was at an all-time high, these oil and gas extraction and support workers received upwards of \$1.1 billion in total wages to spend in their communities.

According to the commenter (0824-WDEQ), the EPA's methodologies for calculating the social cost of methane in the proposed rule overstate societal benefits, while significantly underestimating the immense costs associated with implementation of the rule for state regulatory agencies, regulated entities, and entire state economies. The commenter recommends that EPA start over-using a realistic predictor of the actual costs and benefits resulting from the proposed rule. When it does, the commenter (Wyoming Department of Environmental Quality (WDEQ)) states that it is confident that the costs of the proposed rule will substantially outweigh its benefits.

Response I-20-14: The commenters contend that the reliance of SC-GHG estimates render any new rulemaking arbitrary and unlawful. Within this final rule, EPA updated the SC-GHG estimates from the Final SC-GHG Report. EPA believes that the Final Report of the SC-GHG represents the latest available science and follows the recommendations of the National Academies of Science, Engineering, and Medicine. Please refer to the RTC Appendix for detailed responses pertaining to the rigor of the updated methodology, including the discounting approach, and responses pertaining to the global focus of the SC-GHG estimates. The EPA disagrees with commenter's (0824-WDEQ) assertion that the rule would have immense economic impacts on Wyoming's economy. In the EPA's assessment of impacts on overall oil and natural gas production, it estimated that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. The commenter provides a high-level overview of the economic impact of the oil and natural gas industry on Wyoming's economy but fails to provide specific evidence of how the rule would have a significant impact on the state beyond generic claims. Relatedly, the EPA disagrees with commenter's (0824-WDEQ) assertion that it significantly underestimates the costs associated with the rule. Beyond generic summary statistics of baseline conditions, commenter provides no supporting data or analysis for its claim regarding regulated entities and

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<sup>110</sup> Wyoming State Geological Survey, Erin A. Campbell, Director, and State Geologist, "Oil & Natural Gas Resources in Wyoming," January 2022 Summary Report.



state economies. With respect to implementation costs for state agencies, see Volume I, Chapter 21, Response I-21-9 of this RTC document.

Comment: Commenter (0921-USCC) supports appropriate consideration of GHG emissions and social cost estimates as part of the cost-benefit analyses for regulatory actions required under the EO 12866 only after the IWG on the SC-GHG develops durable SC-GHG estimates that are established through a robust science, economic, and stakeholder engagement process.<sup>111</sup> Through the process mandated by EO 13990, the discount rates that underpin the SC-GHG are being revised and will substantially affect how those standards ultimately get finalized.<sup>112</sup> A recent brief filed by the Department of Justice (DOJ) in litigation challenging the interim SCC estimates suggested that the IWG will propose revised final SCC estimates in the spring of 2022, and that the public will be given an opportunity to comment.<sup>113</sup> The commenter recommends that EPA allow the process of the IWG to conclude and should then conduct a further robust notice and comment process before finalizing the cost-benefit analysis relating to this Proposal. An open public process is critical to public trust in scientific information, analysis, and its real-world application. The commenter adds that any reliance on SC-GHG estimates as currently published should proceed cautiously, as the federal government's SC-GHG estimates are all under review and subject to change.

Commenter (0921-USCC) suggests that EPA, in its cost-benefit analysis for the methane regulation, continue to follow longstanding requirements and principles that apply to the development of such analyses and should treat the SC-GHG estimates with appropriate caution, as these estimates are not yet final and are not appropriately reliable at this time.<sup>114</sup> The EPA's RIA for the 2021 November proposal makes a number of assumptions that feed into the monetized benefits and costs associated with the rule (e.g., climate benefits, compliance costs, and value of product recovery generated by the capture of natural gas). The EPA should carefully consider how it applies the estimates so as not to prejudge, or create problematic inconsistencies with, the outcomes of the IWG process, which we now know is expected to be a more thorough evaluation of the SC-GHG estimates. Through the process to revise the SC-GHG estimates, the commenter suggests that the IWG has an excellent opportunity to establish sound estimates

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<sup>111</sup> See U.S. Chamber of Commerce et al., Comments on Notice of Availability and Request for Comment on the "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (June 21, 2021); see also U.S. Chamber of Commerce et al., Comments on "Certification of New Interstate Natural Gas Facilities (Docket No. PL18-1-000)" (May 26, 2021).

<sup>112</sup> See Memorandum for the Heads of Executive Departments and Agencies, "Modernizing Regulatory Review, January 20, 2021, 86 Fed. Reg. 7223 (Jan. 26, 2021), which amongst other matters directs the Office of Management and Budget ("OMB") to recommend ways to revise OMB's 2003 Circular A-4, Regulatory Analysis – a document detailing best practices for measuring costs and benefits by federal agencies – so that the new circular "fully accounts for regulatory benefits that are difficult or impossible to quantify." See also IWG on Social Cost of Greenhouse Gases "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, United States Government" (Feb. 2021), 86 Fed. Reg. 24,669 (May 7, 2021). SC-GHG estimates are commonly calculated using economic models known as IAMs to translate a marginal increase in emissions into a future physical climate response and then into a subsequent economic impact. A discount rate is applied to convert future damages into present-day value. Key considerations in calculating SC-GHG estimates include the geographic scope, discount rate, and IAM used (as well as the model's assumptions, many of which are user-defined).

<sup>113</sup> Def. Supp. Br., 23, *La. v. Biden*, No. 2:21-cv-01074 (W.D. La. Jan. 21, 2022).

<sup>114</sup> See Opposition of U.S. Dep't of Justice Motion for Preliminary Injunction, *Louisiana v. Biden*, No. 2:21-cv01074-JDC-KK (W.D. La. Sept. 1, 2021), ECF No 68.

based on the best available, peer-reviewed science. The Chamber wants to assist the IWG in this regard as this process continues.<sup>115</sup> The commenter further recommends that EPA's supplemental methane proposal allow for the IWG process to conclude and should utilize the full outcome of the IWG process in an updated cost-benefit analysis for the Proposal.

Commenter (0763-TCEQ) believes the EPA's use of the interim estimates for the social cost of methane (SC-CH<sub>4</sub>) in the 2021 November proposal RIA, as directed under EO 13990, for the proposed rule is illegal. The commenter (0763-TCEQ) states that the SC-CH<sub>4</sub> interim estimates are central to the EPA's RIA for this proposed rulemaking. However, the interim values themselves have not been subject to scrutiny outside the IWG through a notice and comment proceeding as required under the federal Administrative Procedures Act (APA). The commenter contends that the EPA cannot use a metric so integral to its rulemaking action that has not been available to the public, is not a final agency action subject to judicial review, and that by its own admission is subject to change before this proposal is final.

Response I-20-15: The interim SC-GHG estimates recommended by the IWG in February 2021 and used in the primary benefit-cost analysis in both the November 2021 Proposal RIA and the December 2022 Supplemental Proposal RIA are the same as the values developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation. Those estimates were subject to public comment in a dedicated OMB led public comment period in 2013 and in the context of dozens of EPA proposed rulemakings that used the estimates. The EPA responded to the comments received within final rulemakings that used the estimates. In addition, the public has had opportunity to comment on the interim IWG estimates following their use in EPA regulatory analyses for numerous proposed rulemakings published since the release of the February 2021 TSD, including in the November 2021 Proposal RIA and the December 2022 Supplemental Proposal RIA.

EPA presented a set of updated SC-GHG estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates and their development in the Appendix of this RTC.

#### 20.2.3.2 Use of Global vs. Domestic Values for Social Cost of Methane (SC-CH<sub>4</sub>)

Comment: Commenters (0577-KIOGA, 0763-TCEQ, 0797-ND DEQ/ND IC, 0802-Kraken Oil & Gas, 0921-US Chamber of Commerce) disagree with EPA's approach for using the global social cost of methane (SC-CH<sub>4</sub>). Commenters (0577-KIOGA; 0802-Kraken Oil & Gas; 0797-ND DEQ/ND IC) recommend that EPA use domestic SC-CH<sub>4</sub> values instead.

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<sup>115</sup> See U.S. Chamber of Commerce et al. Comments on Notice of Availability and Request for Comment on the "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (June 21, 2021), pp. 5-6.

Commenter (0763-TCEQ) states that, in the 2021 November proposal RIA, the EPA uses a SC-CH<sub>4</sub> metric that significantly overestimates the benefits and underestimates the costs of regulating methane from this industrial sector of the U.S. economy. The EPA applied its SC-CH<sub>4</sub>, based on global climate impacts, to the methane emission reductions expected from this proposed rule and came up with, for example, an average benefit yield of \$190 million in 2023 increasing to \$4.8 billion in 2035 (based on a 3% discount rate). By comparison, estimating SC-CH<sub>4</sub> using climate impact/damages only within the U.S. yields a climate benefit of \$25 million in 2023 and \$920 million in 2035. This is a significant reduction in benefits when looking at only impacts within the U.S. from a regulation that affects only U.S. sources.

The commenter (0763-TCEQ) adds that the EPA fails to adequately explain why estimating climate benefits or impacts that may occur internationally to U.S. citizens' health and welfare are readily available and accurately ascertainable. The commenter explains that this rulemaking impacts only the U.S. oil and gas industry emissions, but the EPA claims an accurate assessment of total climate damages must account for impacts outside the U.S. However, the commenter adds that the EPA only assumes that this regulation will have "spillover effects" (2021 November proposal RIA, p. 315, Table 3-4, fn b) on mitigation efforts elsewhere in the world. ("In addition, assessing the benefits of the U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating impacts that affect U.S. citizens and residents." (2021 November proposal RIA, p. 3-9)) According to the commenter, the EPA provides no evidence that these international actions are likely to occur in the future. And yet, the EPA also agrees with the IWG's claim in its TSD that estimating climate benefits occurring solely within the U.S. are more subject to uncertainty or underestimation, arguing that the lower climate benefits from looking only within the U.S. were only an "approximation."

Commenter (0802-Kraken Oil & Gas) states that contrary to the intent of "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use" under EO 13211, 2021 November proposed actions are based on a fundamentally flawed cost-benefit analysis by comparing global benefits of methane emissions reductions with domestic cost of compliance, thereby skewing the balance in favor of the benefits of the proposed actions for NSPS OOOOa, NSPS OOOOb, and EG OOOOc. The commenter states that the significant cost of carbon difference (i.e., the global SC-CH<sub>4</sub> is \$51/ton and the US SC-CH<sub>4</sub> is \$7/ton) creates an unbalanced regulatory cost-benefit analysis, a fundamentally flawed GHG emission calculation basis, which in turn leads to overstated domestic GHG emissions, more GHG emissions than would result in the absence of regulation, and EPA making regulatory decisions to restrict domestic activity based on a global calculation basis. The commenter further states that the EPA does not have any basis in the CAA that would allow this comparison. The commenter cites to Western Energy Alliance (WEA) comments on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (submitted June 21, 2021, via Regulations.gov) in which WEA reiterated the purpose of the CAA regarding determining the impact from proposed rulemaking actions.

A focus on domestic impacts only also aligns well with the principles laid out in the Clean Air Act. In section 101(b)(1) of the Clean Air Act, for example, Congress wrote that the purpose of the Act is to "protect and enhance the quality of the Nation's air

resources so as to promote the public health and welfare and productive capacity of its population.” This language has led to interpretation used by multiple agencies that the Clean Air Act is limited to covering impacts and benefits of regulation domestically.

Commenter (0921-US Chamber of Commerce) states that EPA’s cost-benefit analysis should be completed only after the IWG on the SC-CH<sub>4</sub> develops durable SC-CH<sub>4</sub> estimates that are established through a robust public stakeholder engagement process.

Commenter (0797-ND DEQ/ND IC) states that EPA’s SC-CH<sub>4</sub> calculations (and the output of the calculations) are entirely speculative, and that EPA is lacking in jurisdiction and expertise to attach a global cost to U.S. methane emissions. According to the commenter, relying on “global benefits” to justify the domestic costs of the 2021 NSPS Proposal is arbitrary and capricious and contrary to law, as decided in *Wyoming vs. Jewell*, the commenter states. The commenter states that the 2021 November proposal RIA provided by EPA does not attempt to calculate the domestic benefits of the 2021 NSPS Proposal, and calculates benefits based solely on alleged global benefits. Even assuming that the SC-CH<sub>4</sub> can be estimated with any reasonable degree of accuracy, the commenter argues, the global estimates can be over 20 times higher per ton of carbon emissions than the equivalent domestic estimates. The commenter suggests that, to adequately justify the 2021 NSPS Proposal, EPA must break out the domestic versus global carbon benefits of the proposal, as was done in the RIA for the 2020 rule. The commenter contends that, until EPA does so, the EPA has not supported this proposed rule with a single dollar arising from a specifically identified benefit accruing to U.S. citizens associated with the reduced methane emissions claimed for this proposal.<sup>116</sup>

Conversely, other commenters (1267-CA, 0804-EDF et al) support the use of the global estimates for SC-CH<sub>4</sub>.

Commenter (1267-CA) states that EPA is not precluded from considering the interim value for the SC-CH<sub>4</sub> established by the IWG, by the major questions doctrine or any other legal doctrine. The commenter explains that EPA’s use of the SC-CH<sub>4</sub> to assess the benefits and impacts of the rule is well within the scope of EPA’s authority to consider the costs and benefits of its actions. The commenter explains that on a handful of occasions, the Supreme Court has invalidated agency regulations on the ground that they, in the Court’s view, far exceeded the agency’s statutory authority, and thus crossed into the realm of legislative policy-making.<sup>117</sup> In these cases, the commenter summarizes that the Court determined that the agencies had made an error

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<sup>116</sup> In citing to *Wyoming vs. Jewell*, the commenter summarizes that “EPA cannot rely on purported benefits that might accrue to citizens outside the United States to justify the imposition of burdens on the citizens of the United States” and that “EPA cannot evade that judicial determination with vague and unquantified references to the effect that climate change impacts occurring outside of U.S. borders might affect the welfare of U.S. citizens by affecting tourism or “spillover pathways” such as economic or political destabilization”; Social Cost of Carbon, Identifying a Federal Entity to Address the National Academies’ Recommendations Could Strengthen Regulatory Analysis, GAO 20-245 (June 2020); Regulatory Impact Analysis for the Proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, Revisions to Emission Guideline Implementing Regulations, Revisions to New Source Review Program at Chapter 7, Section 7.3 (Forgone Global Climate Benefits).

<sup>117</sup> *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 324 (2014); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159-60 (2000); *MCI Telecommunications Corp. v. AT&T*, 512 U.S. 218, 231 (1994).

of kind, not just degree, by crossing specific statutory lines Congress had drawn.<sup>118</sup> The commenter explains, however, that nothing in those cases prohibits an agency, when acting within a clear delegation of statutory authority,<sup>119</sup> to consider the costs and benefits of its action using a well-established, scientifically sound analytical tool such as the SC-CH<sub>4</sub>.<sup>120</sup> The commenter believes that the SC-CH<sub>4</sub> is an important analytical tool that is used by agencies to translate certain impacts of GHG-emitting actions that they may consider into dollars and this dollar figure can then be compared to other projected costs or benefits to better inform agency decision-making. The commenter believes this cost-benefit analysis is consistent with CAA section 111, which instructs EPA to consider “cost” as well as “non air quality health and environmental impact[s]” when evaluating the BSER.<sup>121</sup> According to the commenter (1267-CA), this approach is also consistent with longstanding administrative practice: citing to EOs and White House guidance documents which have, for decades and across Presidential administrations, instructed agencies to “use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible.”<sup>122</sup> The commenter cites to the Supreme Court which stated that “[c]onsideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions.”<sup>123</sup> Further, the commenter argues, agencies across the federal government, as well as state agencies and local governments, have incorporated some form of SC-CH<sub>4</sub> for years now, resulting in an increase in the rationality of agency decision-making, not the imposition of any unwarranted economic harm. The commenter believes that an evaluation of the cost and benefits of an agency action that will impact methane emissions that does not use the SC-CH<sub>4</sub> would be woefully incomplete.<sup>124</sup>

Moreover, the commenter (1267-CA) states, the SC-CH<sub>4</sub> does not dictate the outcome of any specific agency rulemaking, including this one. In the proposal, the commenter understands that while EPA considers the SC-CH<sub>4</sub> in evaluating the costs and benefits of the proposed rule (as it must), nowhere does the agency suggest that those values were used to determine the BSER for the oil and natural gas sector, or that they will be determinative of its ultimate decision to promulgate the rule. The commenter believes that approach is consistent with CAA section 111, which directs EPA to take costs “into account,” but does not require EPA to precisely balance

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<sup>118</sup> *UARG*, 573 U.S. at 325 (the commenter summarizes the Court rejected EPA’s decision to “rewrite[e] unambiguous statutory terms”); *Brown & Williamson*, 529 U.S. at 141 (the commenter states the Court said that FDA’s regulation of tobacco would be “incompatible with” other statutory provisions).

<sup>119</sup> 42 U.S.C. § 7411.

<sup>120</sup> *Biden v. Missouri*, Case Nos. 21A240 & 21A241, Slip Op. at 6 (Jan. 13, 2022) (per curiam) (the commenter summarizes the case upheld the vaccine mandate for healthcare workers promulgated by the Department of Health and Human Services because it was consistent with “longstanding practice” of agency to impose conditions necessary to “address the safe and effective provision of healthcare”).

<sup>121</sup> 42 U.S.C. § 7411(a)(1).

<sup>122</sup> Improving Regulation and Regulatory Review, EO 13563 § 1(c), 76 Fed. Reg. 3821 (Jan. 18, 2011); accord Regulatory Planning and Review, EO 12866 §§ 1, 6(a)(3)(C), 58 Fed. Reg. 51735 (Oct. 4, 1993) (the commenter states this requires agencies to assess “all costs and benefits” of regulatory actions and alternatives, including “quantifiable measures[] to the fullest extent that [they] can be usefully estimated”); OMB, Circular A-4: Regulatory Analysis at 2, 18 (2003) (the commenter states Circular A-4 instructs agencies that expression of “potential real incremental benefits and costs” of their actions “in monetary units” provides “useful information for decision makers and the public”).

<sup>123</sup> *Michigan v. U.S. Env’t Prot. Agency*, 576 U.S. 743, 753 (2015).

<sup>124</sup> *Michigan*, 576 U.S. at 752 (the commenter states that “‘cost’ includes more than the expense of complying with regulations; any disadvantage could be termed a cost.”); *Center for Biological Diversity*, 538 F.3d at 1200-1201.

costs against benefits before promulgating a CAA section 111 regulation. Indeed, the commenter states, the 2021 November proposal RIA also evaluates several “non-monetized benefits” and that the SC-CH<sub>4</sub> is simply one additional tool for monetizing some of the benefits of a regulation that would otherwise be non-monetized, not a thumb on the scale of agency cost-benefit analyses.<sup>125</sup>

Finally, the commenter (1267-CA) states that none of the cases upholding federal environmental reviews that declined to use the SC-CH<sub>4</sub> demonstrate that the SC-CH<sub>4</sub> cannot be employed by federal agencies. The commenter cites by way of example, *EarthReports, Inc. v. FERC*, where the D.C. Circuit held only that FERC was not required to use the SC-CH<sub>4</sub>, based on the specific record before it, but did not suggest FERC was barred from using the SC-CH<sub>4</sub>.<sup>126</sup>

Commenter (0804-EDF et al) states that EPA should rely on legal requirements under the CAA, the NEPA, the APA and other key sources of law that not only permit, but in fact require EPA to consider national effects. The commenter states that section 111 of the CAA charges EPA with regulating “air pollution which may reasonably be anticipated to endanger public health or welfare,” where “welfare” is defined to include “effects on . . . weather . . . and climate.” When interpreting similar language in section 202 of the CAA, the commenter summarizes, the Supreme Court found “there is nothing counterintuitive to the notion that EPA can curtail the emission of substances that are putting the global climate out of kilter.” The commenter cites to another case, when industry challenged another EPA climate program under Title I of the CAA, by arguing that the statute “was concerned about local, not global effects.” The commenter summarizes that the U.S. Court of Appeals for the D.C. Circuit had “little trouble disposing of Industry Petitioners’ argument that the [CAA’s prevention of significant deterioration] program is specifically focused solely on localized air pollution,” finding instead that the statute was “meant to address a much broader range of harms,” including “precisely the types of harms caused by greenhouse gases.”<sup>127</sup>

The commenter (0804-EDF, et. al.) also draws on statements from environmental and administrative law scholar Richard Revesz. According to the commenter, Mr. Revesz has exhaustively reviewed the legislative history of the CAA’s definition of “welfare” and has concluded that “when Congress included the ‘effects on . . . climate’ language in the statute, it understood that adverse climate effects could occur on a global scale.” The commenter provides statements from U.S. senators, by way of example and concludes that Congress’s clear concern

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<sup>125</sup> 42 U.S.C. § 7411(a)(1); *Portland Cement Ass’n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975) (the commenter summarized that although EPA conceded that relating costs of section 111 standard to benefits was “practical impossibility,” industry failed to show it could not “adjust itself in a healthy economic fashion” to the rule).

<sup>126</sup> 828 F.3d 949, 956 (D.C. Cir. 2017).

<sup>127</sup> 42 U.S.C. § 7411(b)(1)(A); U.S.C. § 7602(h); *Massachusetts v. EPA*, 127 S. Ct. 1438, 1447 (2007); *Massachusetts*, 127 S. Ct. at 1461 (the commenter summarized that this case concerned section 202 of the CAA, which similarly permits EPA to regulate “any air pollutant . . . which may reasonably be anticipated to endanger public health or welfare”); *Id.* at 1454 (quoting 42 U.S.C. § 7521(a)(1)); *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 137-38 (D.C. Cir. 2012), *aff’d in part, rev’d in part sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

for the effects of domestic pollution on the global climate demonstrates that a global perspective is appropriate, if not required, when EPA regulates under the CAA.<sup>128</sup>

Regarding NEPA, the commenter (0804-EDF, et. al.) states that adopting a global perspective on climate damages will advance U.S. foreign policy goals, NEPA requires EPA to interpret all its laws, including the CAA, in ways that recognize the worldwide character of environmental problems; using global social cost of GHG estimates helps fulfill that requirement. The commenter states that the interpretation [that EPA must consider global impacts] is further compelled because NEPA much more broadly declares a national environmental policy and requires of all agencies that “to the fullest extent possible[,] the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter,” including the need to “recognize the worldwide and long-range character of environmental problems” and to “lend appropriate support” to help “maximize international cooperation.”<sup>129</sup>

The commenter (0804-EDF et al) believes that other key legal commitments<sup>130</sup> compel this same conclusion.

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<sup>128</sup> Richard L. Revesz, Bostock, and the End of the Climate Change Double Standard, 46 COLUM. J. ENV'T L. 1, 9 (2020); Senator Caleb Boggs, a Republican from Delaware and ranking minority member of the Public Works Subcommittee on Air and Water Pollution, which was considering the CAA in 1970, entered a report into the record stating that air pollution “alters climate and may produce global changes in temperature” and Senator Jennings Randolph of West Virginia likewise submitted a statement into the record explaining that U.S. air pollution could “produce unacceptable worldwide climate changes.” Id. at 32–33.

<sup>129</sup> 42 U.S.C. § 4332(1); Id. § 4332(2)(F); see also *EDF v. Massey*, 986 F.2d 528, 536 (D.C. Cir. 1993) (the commenter summarizes that “[s]ection 102(2)(F) further supports the conclusion that Congress, when enacting NEPA, was concerned with worldwide as well as domestic problems facing the environment...[c]ompliance with one of the subsections can hardly be construed to relieve the agency from its duty to fulfill the obligations articulated in other subsections”); *NRDC v. NRC*, 647 F.2d 1345, 1387 (D.C. Cir. 1981) (J. Robinson, concurring; J. Wilkey wrote for the Court, but there was no majority opinion) (the commenter summarizes that the Court concluded that even if a conflict with another statute prevents the agency from conducting an environmental impact statement, that “does not imply that NRC may ignore its other NEPA obligations,” including the “provision for multinational cooperation” and the “policy of the United States with respect to the ecological well-being of this planet”; rather, the agency “should remain cognizant of this responsibility”); *Greene County Planning Bd. v. Federal Power Comm’n*, 455 F.2d 412, 424 (2d Cir. 1972) (the commenter summarizes that the Court found “[t]he Commission’s ‘hands-off’ attitude is even more startling in view of the explicit requirement in NEPA that the Commission ‘recognize the worldwide and long-range character of environmental problems’ and interpret its mandate under the Federal Power Act in accordance with the policies set forth in NEPA”).

<sup>130</sup> See United Nations Framework Convention on Climate Change (Convention), S. Treaty Doc. No. 102-38; S. Exec. Rept. No. 102-55; U.N. Framework Convention on Climate Change art. 3(3), May 9, 1992, 1771 U.N.T.S. 107; see also id. art. 3(1) (the commenter summarizes that “[t]he Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities”); id. art. 4(2)(a) (the commenter summarizes commitments by developed countries to adopt policies that account for “the need for equitable and appropriate contributions by each of these Parties to the global effort”); Id. art. 4(1)(f); see also id. art. 3(2) (the commenter summarizes the requirement of parties to give “full consideration” to those developing countries “particularly vulnerable to the adverse effects of climate change”); see also North American Agreement on Environmental Cooperation art. 10(7), Jan. 1, 1994, 32 I.L.M. 1480 (the commenter summarizes the commitment of the United States to the development of principles for transboundary environmental impact assessments); Comment Letter from U.S. Sens. Feinstein, Snowe, Nelson, Cantwell, Sanders, Kerry, Durbin, Reed, Boxer, & Cardin to Mary Peters,

Finally, the commenter (0804-EDF et al) examines requirements under APA, where the commenter states it is arbitrary and capricious for agencies to “entirely fail[] to consider an important aspect of the problem” - an obligation, the commenter states, a federal court held requires federal agencies to consider international climate impacts. The commenter summarizes that the court found that the global values developed by the IWG reflected “the best available science about monetizing the impacts of greenhouse gas emissions,” whereas “focusing solely on domestic effects has been soundly rejected by economists as improper and unsupported by science.” The commenter also cites to statements by the court that relevant executive orders, including Executive Order (EO) 12866, require consideration of “all” costs and benefits, based on the “best reasonably obtainable scientific, technical, economic, and other information,” and concluded that “no[] . . . regulatory rules or orders require exclusion of global impacts.” More recently, the commenter states, EO 13990 instructed agencies to “tak[e] global damages into account,” because “[d]oing so facilitates sound decision-making, recognizes the breadth of climate impacts, and support the international leadership of the United States on climate issues.”<sup>131</sup>

In addition to legal requirements under the CAA, NEPA, and APA, the commenter (0804-EDF et al) states that spillover impacts into the U.S. and transboundary resources also support the use of global damage valuations, as significant costs to trade, human health, and security will inevitably “spill over” to the U.S. as other regions of the planet experience climate change damages. According to the commenter, all these individual spillover effects can also interact and trigger feedback loops that will propagate additional spillover damages, according to the commenter. The commenter states that experts on SC-CH<sub>4</sub> have therefore concluded that, because the IAMs that underlie the IWG’s social cost valuations currently do not capture many of these key inter-regional costs, use of the global values can be further justified as a proxy for capturing all spillover effects. The commenter recommends that, in addition to the spillover effects that EPA already mentions, EPA should argue that transboundary spillovers, feedback loops, information spillovers, and other effects justify a focus on the full global values, either independently or in combination with other strategic and ethical considerations.<sup>132</sup>

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Sec’y, U.S. Dep’t of Transp. on Proposed Rule for Average Fuel Economy Standards, Passenger Cars and Light Trucks; Model Years 2011–2015 (July 1, 2008).

<sup>131</sup> *Motor Vehicle Mfrs. Ass’n v. State Farm*, 463 U.S. 29, 41–43, (1983); *Bernhardt*, 472 F. Supp. 3d at 613 (the commenter states a recent ruling from the U.S. Court for the Northern District of California struck down as arbitrary the Bureau of Land Management’s (BLM) rescission of the Waste Prevention Rule in part because the agency had abandoned the IWG’s peer-reviewed, global estimates of the social cost of greenhouse gases in favor of flawed estimates (the commenter states these are the same estimates that EPA applied under the Trump administration) that looked narrowly at effects within the U.S. borders); *Id.* at 611–12; EO 13990 § 5(a), 86 Fed. Reg. 7037, 7040 (Jan. 20, 2021).

<sup>132</sup> RIA at 3-9; 2021 Vehicle Emissions Standards RIA at 3-31; S. Rao et al., Importance of Technological Change and Spillovers in Long-Term Climate Policy, 27 *ENERGY J.* 123–39 (2006) (the commenter states that some positive spillover effects are also possible, such as technology spillovers that reduce the cost of mitigation or adaptation); Jody Freeman & Andrew Guzman, Climate Change and U.S. Interests, 109 *COLUM. L. REV.* 1531 (2009) [herein after Freeman & Guzman] (the commenter states that overall climate spillovers are likely strongly negative); U.S. Global Change Res. Prog., Fourth National Climate Assessment, Volume II: Impacts, Risks, and Adaptation in the United States, Chapter 16: Climate Effects on U.S. International Interests 608 (2018) [hereinafter NCA4]; Steven L. Schwarcz, Systemic Risk, 97 *GEO. L.J.* 193, 249 (2008) (the commenter references the



The commenter (0804-EDF et al) makes related points that it is in the strategic interest of the U.S. to encourage all other countries to think globally in setting their climate policies and that the U.S. can advance this objective by itself adopting the full global social cost of GHGs. The commenter states, both empirical evidence and economic theory strongly support a strategic choice for U.S. agencies to adopt the full global estimates of the social cost of GHGs, as this facilitates international reductions in GHG pollution that directly benefits the U.S. The commenter urges EPA to provide current evidence of foreign reciprocity to further support its focus on the full global valuations of the social cost of GHGs. The commenter believes there already is evidence that the U.S. strategy of combining its domestic efforts, including the global valuation of climate damages, with its diplomatic engagement is spurring foreign reciprocity. Conversely, by failing to take international climate damages into account, the commenter states, EPA, and other U.S. agencies would incentivize other countries to do the same, which in turn would cause greater GHG pollution originating in other countries that causes climate damage within the U.S.<sup>133</sup>

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observation that financial collapse in one country is inevitably felt beyond that country's borders); CNA Military Advisory Board, National Security and the Accelerating Risks of Climate Change (2014); U.S. Gov't Accountability Off., GAO-14-446, Climate Change Adaptation: DOD Can Improve Infrastructure Planning and Processes to Better Account for Potential Impacts (2014); Union of Concerned Scientists, The U.S. Military on the Front Lines of Rising Seas (2016); U.S. Dep't of Def., Report on Effects of a Changing Climate to the Department of Defense 8 (2019), <https://perma.cc/4WPP-86EN>; U.S. Dep't of Def., Quadrennial Defense Review 2014 at vi, 8 (2014); NCA4, *supra* note 24, at 607; *Id.* at 615; Peter Howard & Michael Livermore, Climate-Society Feedback Effects: Be Wary of Unidentified Connections, *INTL. REV. ENV'T & RES. ECON.* (forthcoming 2021); Peter Howard & Michael A. Livermore, Sociopolitical Feedbacks and Climate Change, 43 *HARV. ENV'T L. REV.* 119, 122-23 (2019) [hereinafter Howard and Livermore]; NCA4, *supra* note 24, at 621 (the commenter references the explanation that instability has economic effects, and economic risks create risk of conflict); Freeman & Guzman, at 1581-89; *Id.* at 1581 (the commenter references the notation that climate-induced pandemics may cause political instability); *Id.* at 1564 n.157 (the commenter references the notation that cross-sectoral interactions will "reinforce" international spillovers and create "a costly multiplier effect"); Robert E. Kopp & Bryan K. Mignone, Circumspection, Reciprocity, and Optimal Carbon Prices, 120 *CLIMATE CHANGE* 831, 833 (2013) (the commenter references the explanation that the principle of "circumspection" can account for spillover effects and can then be used to justify a global SC-CH<sub>4</sub> value); Katharine Ricke et al., Country-Level Social Cost of Carbon, 8 *NATURE CLIMATE CHANGE* 895 (2018) [hereinafter CSCC] (the commenter states the authors concede that after factoring in spillovers and other considerations, an individual country's interests may be better reflected in a global valuation than a country-specific valuation, and it may not be appropriate to use a country-specific valuation in setting climate policies: Globalization and the many avenues by which the fortunes of countries are linked mean that a high CSCC in one place may result in costs as the global climate changes even in places where the CSCC is nominally negative. For many countries, the effects of climate change may be felt more greatly through transboundary effects, such as trade disruptions, large-scale migration, or liability exposure than through local climate damage... These considerations suggest that country-level interests may be more closely aligned to global interests than indicated by contemporary country-level contributions to the SCC... [A] host of other strategic and ethical considerations factor into the international relations of climate change mitigation... We make no claim here regarding the utility of the CSCC in setting climate policies. CO<sub>2</sub> emissions are a global externality. *Id.* at 899); RIA at 3-9 (the commenter references cites to trade, tourism, economic spillovers, political destabilization, and global migration); Jason A. Schwartz, Inst. for Pol'y Integrity, Strategically Estimating Climate Pollution Costs in a Global Environment (2021), [https://policyintegrity.org/files/publications/Strategically\\_Estimating\\_Climate\\_Pollution\\_Costs\\_in\\_a\\_Global\\_Environment.pdf](https://policyintegrity.org/files/publications/Strategically_Estimating_Climate_Pollution_Costs_in_a_Global_Environment.pdf), at 26; *Id.* at 12 (the commenter references information spillovers).

<sup>133</sup> Matthew J. Kotchen, Which Social Cost of Carbon? A Theoretical Perspective, 5 *J. ASSOC. ENV'T & RES. ECON.* 673, 683 (2017) [hereinafter Kotchen] (the commenter states that most generally, it is individually rational

Commenter (0804-EDF, et. al.) further states that U.S. extraterritorial interests also support a global valuation for SC-CH<sub>4</sub>, and they recommend that EPA highlight U.S. extraterritorial interests as further justification for relying on global social cost valuations, and suggests specifically that EPA call attention to climate-vulnerable U.S. military installations abroad with high replacement costs or irreplaceable strategic value, U.S. willingness to pay to protect

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for a country to fully internalize the global social cost of greenhouse gases “if a country expects a decrease in its own emissions to decrease that of all others in proportion to the ratio of its external cost of emissions to its internal costs”); Tamma Carleton & Michael Greenstone, Updating the United States Government’s Social Cost of Carbon at 26-27 (Becker Friedman Institute Working Paper 2021-04, Jan. 2021), <https://perma.cc/H9EU-XWBX> (the commenter states that other economists have justified use of the global social cost estimates on more intuitive grounds, “[t]he global SCC . . . is an ingredient in efforts to procure the necessary international action. . . . [e]ven if policymakers decide that the effects of regulations on U.S. citizens are what matter (in terms of both law and policy”), it would make sense to use the global measure, as it would protect U.S. citizens against a range of adverse effects from unmitigated climate change.”); William Pizer et al., Using and Improving the Social Cost of Carbon, 346 SCIENCE 1189, 1190 (2014) (the commenter references the explanation that the “potential to leverage foreign mitigation,” combined with moral, ethical, and security issues, provide “compelling reasons to focus on a global SCC but, more important, to make a strategic choice”); Robert S. Pindyck, Comments on Proposed Rule and Regulatory Impact Analysis on the Delay and Suspension of Certain Requirements for Waste Prevention and Resource Conservation, Nov. 6, 2017, <https://perma.cc/HG8Q-MT6H> (the commenter summarizes “[W]hat treatment of international damages is in the United States’ self-interest? . . . The simplest answer is to find the value of the [social cost of carbon] that maximizes global welfare. . . . I continue to think that the global value is the appropriate provisional value for use as research on this topic continues”); Kotchen, at 678 (the commenter references the providing of formulas for the “efficiency argument in support of all countries internalizing the GSCC [global social cost of carbon] for domestic policy”); Inst. for Pol’y Integrity, Foreign Action, Domestic Windfall: The U.S. Economy Stands to Gain Trillions from Foreign Climate Action (2015), <https://perma.cc/T3WN-H42U>; EO 13990 § 5(a); Inst. for Pol’y Integrity, Foreign Action, Domestic Windfall: The U.S. Economy Stands to Gain Trillions from Foreign Climate Action (2015), <https://perma.cc/T3WN-H42U>; EO No 13990 §6(d) (the commenter states that though this subsection takes action on the Keystone XL Pipeline permit, its statement of diplomatic goals has much broader relevance); U.S. Dept. of State, Leaders’ Summit on Climate: Day 1, Apr. 22, 2021, <https://perma.cc/3X8A-KF4G>; Climate Action Tracker, Warming Projections Global Update: May 2021 at 3 (2021), <https://perma.cc/7JYN-N2DU>; U.N., Kigali Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer (2016), <https://perma.cc/SEX3-HAQA> (last visited June 8, 2021); Eur. Comm’n, Expression of Willingness to Be Associated with the Copenhagen Accord and Submission of the Quantified Economy-Wide Emissions Reduction Targets for 2020 at 2, Jan. 28, 2010, EO 13990 § 5(a); Id. § 6(d) (the commenter states that though this subsection takes action on the Keystone XL Pipeline permit, its statement of diplomatic goals has much broader relevance); U.S. Dept. of State, Leaders’ Summit on Climate: Day 1, Apr. 22, 2021, <https://perma.cc/3X8A-KF4G>; Climate Action Tracker, Warming Projections Global Update: May 2021 at 3 (2021), <https://perma.cc/7JYN-N2DU>; U.N., Kigali Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer (2016), <https://perma.cc/SEX3-HAQA> (last visited June 8, 2021); Eur. Comm’n, Expression of Willingness to Be Associated with the Copenhagen Accord and Submission of the Quantified Economy-Wide Emissions Reduction Targets for 2020 at 2, Jan. 28, 2010, <https://perma.cc/77DDM4LS> (the commenter references a commitment to a 20% reduction but “reiterat[es] its conditional offer to move to a 30% reduction by 2020 compared to 1990 levels, provided that other developed countries commit themselves to comparable emission reductions and that developing countries contribute adequately according to their responsibilities and respective capabilities”); Gov’t of Mex. Ministry of Env’t & Nat. Res., Nationally Determined Contributions: 2020 Update at 22, <https://perma.cc/VF4A-K5HK> (the commenter references making an unconditional pledge of 22% reduction of GHGs and 51% of black carbon by 2030; and making a conditional pledge of up to 36% reduction GHGs and 70% black carbon, conditioned on “an international price for carbon trading, adjustment of tariffs for carbon content” as well as technology transfers and financial resources); Economics of Climate Change: Hearing before the U.S. H. Comm. on Oversight & Reform’s Subcomm. on Env’t at 6 (Dec. 19, 2019) (the commenter references the testimony of Michael Greenstone), <https://perma.cc/H5JS-V4H6>; Trevor Houser & Kate Larsen, Rhodium Grp., Calculating the Climate Reciprocity Ratio for the U.S. (2021), <https://perma.cc/7MJ8-DN23> (the commenter states they call their estimate “deliberately conservative”).

relatives, ancestral homes, cultural and religious sites, and natural resources located abroad, and U.S. altruism toward the people, animals, and natural habitats across the globe.<sup>134</sup>

Commenter (0804-EDF et al) states that in instances where EPA discusses domestic climate impacts, EPA uses a flawed domestic-only values developed under the now revoked EO 13783 (the commenter states this was acknowledged by EPA in the recently published regulatory impact statement for the final vehicle emissions standards). The commenter states EPA should make clear (in this rule) that the values are arbitrary and invalid and should not be relied on. Further, the commenter states that EPA should consider conducting a sensitivity analysis using a more realistic domestic-only valuation of the social cost of GHGs and should look to the IWG's past (and future, when available) guidance to ascertain values, while still maintaining that the global perspective is the correct focus for its main analysis. Such sensitivity analysis by EPA of domestic climate impacts, the commenter states, would confirm that the proposed rule would be cost-benefit justified using domestic-only values, and thus the use of such valuations would not affect the agency's regulatory approach.<sup>135</sup>

Response I-20-16: EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material

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<sup>134</sup> RIA at 3-9; David A. Dana, Valuing Foreign Lives and Civilizations in Cost-Benefit Analysis: The Case of the United States and Climate Change Policy 10 (Northwestern Faculty Working Paper 196, 2009), <https://perma.cc/EW3B-NKYC>; Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates Under Executive Order 13,990 at 4 (2021) [hereinafter 2021 TSD] at 15 (citing a 2016 figure from Bureau of Consular Affairs, Dept. of State); Dept. of State, Consular Affairs by the Numbers (2020), <https://perma.cc/F3M8-EFSJ>; Ctr. for Climate & Sec., Military Expert Panel Report: Sea Level Rise and the U.S. Military's Mission 7 (2d ed. 2018), <https://perma.cc/ZM4R-ED89>; OMB, Circular A-4: Regulatory Analysis 22 (2003); U.S. Census Bureau, Characteristics of the U.S. Population by Generational Status: 2013 at 3 (2016), <https://perma.cc/AS3H-BCWK>; Pew Res. Ctr., First- and second-generation share of the population, 1900-2017, June 3, 2019, <https://perma.cc/Y9WT-75R4>; Pew Res. Ctr., Key Findings About U.S. Immigration, Aug. 20, 2020, <https://perma.cc/8JEK-Y88S>; Pew Res. Ctr., Remittance Flows Worldwide in 2017, Apr. 3, 2019, <https://perma.cc/D684-7ZA8>; Yu Fang & James W. Jawitz, The evolution of human population distance to water in the USA from 1790 to 2010, 10 NATURE COMMUNICATIONS 1 (2019); Lee Boshier et al., Dealing with multiple hazards and threats on cultural heritage sites: an assessment of 80 case studies, 29 DISASTER PREVENTION AND MANAGEMENT: AN INTERNATIONAL JOURNAL 109 (2019); W. Neil Adger et al., Cultural dimensions of climate change impacts and adaptation, 3 NATURE CLIMATE CHANGE 112 (2013); Ali Ardeshiri et al., Conservation or Deterioration in Heritage Sites? Estimating Willingness To Pay for Preservation (Working Paper, 2019); Arden Rowell, Foreign Impacts and Climate Change, 39 HARV. ENV'T'L. L. REV. 371 (2015); Dana, supra note 26; UNESCO, Climate Change Now Top Threat to Natural World Heritage, Dec. 2, 2020, <https://perma.cc/K9SW-XQDM>; Datablog, A History of CO<sub>2</sub> Emissions, THE GUARDIAN (Sept. 2, 2009).

<sup>135</sup> 2021 Vehicle Emissions Standards RIA at 3-31 (citing 2021 TSD, supra note 26); RIA at 3-15 note b; Bernhardt, 472 F. Supp. 3d at 613; Schwartz, supra note 24, at 39-40; Working Group, Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis 11 (2010), <https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbonfor-RIA.pdf> [hereinafter 2010 TSD]; Dept. of Energy, Technical Support Document: Energy Efficiency Program for Consumer Products: Residential Central Air Conditioners and Heat Pumps at 14-3 & n.b., 14-6 to 14-7 (2016); RIA at 1-13 tbl. 1-6.

to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates, including comments pertaining to the global focus of the SC-GHG estimates, in the Appendix of this RTC.

Comment: Commenters (0577-KIOGA, 0804-EDF et al) discuss the use of global estimates for SC-CH<sub>4</sub> within the context of compliance costs. Commenter (0577-KIOGA) states that their experience is that EPA often underestimates the cost of compliance and overestimates the benefits provided by proposed regulations. The commenter provides a table (see Table 1 of their comment letter) in their comment letter, comparing the changes in tons of pollutants reduced (methane, VOC, and HAP), climate benefits, total capital expenditures, total engineering expenditures and beneficial value of methane recovered, between the proposed and final NSPS OOOOa rulemaking. Commenter (0804-EDF et. al.) states that all industry compliance costs ultimately fall on the owners, employees, investors, or customers of regulated and affected firms and a significant portion ultimately will accrue to foreign customers or foreign investors. Because EPA does not distinguish between compliance costs which accrue to foreign entities (as opposed to U.S. citizens or entities), the cost implicitly includes all global effects; considering global climate benefits is consistent with that approach. The commenter recommends that EPA highlight its consistent treatment of costs and benefits as further justification for relying on global social cost of GHG valuations.<sup>136</sup>

Response I-20-17: The EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates, including comments pertaining to the global focus of the SC-GHG estimates, in the Appendix of this RTC.

#### 20.2.3.3 Use of Consumption-Based Discount Rates, Choice of Appropriate Discount Rate, and Determination of Present Value of Future Climate Benefits

Comment: Commenter (0910-AGKY) notes the sheer uncertainty of the SCC estimate caused by the IWG's break with the Executive Branch's longstanding approach to discount rates. See, e.g., Cong. Research Serv., *Attaching a Price to Greenhouse Gas Emissions with a Carbon Tax or Emissions Fee: Considerations and Potential Impacts* 6-8 (Mar. 22, 2019), <https://bit.ly/3v1oifZ> ("One potential challenge of relying on SC-CO<sub>2</sub> estimates to set a carbon fee are methodological

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<sup>136</sup> Dept. of Treasury et al., *Foreign Portfolio Holdings of U.S. Securities* at B-3 (2020), <https://perma.cc/6VP6-PPG6>; Steve Rosenthal & Theo Burke, *Who's Left to Tax? U.S. Taxation of Corporations and Their Shareholders* at 2 (Urban-Brookings Tax Policy Center Working Paper, 2020), <https://perma.cc/YMR2-XREM>; Exxon Mobil Corp., CNN Business, <https://money.cnn.com/quote/shareholders/shareholders.html?symb=XOM&subView=institutional> (last visited Dec. 27, 2021); RIA for the Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources at 3-13 (2018); EPA, *Regulatory Impact Analysis for the Proposed Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS* at 5-5 (2020); EPA, *Draft Guidelines for Preparing Economic Analyses: Review Copy* prepare for EPA's Science Advisory Board at 5-2 (2020), <https://perma.cc/3K86-M7AH>; *Ctr. for Biological Diversity*, 538 F.3d at 1198.

concerns. ... No estimates of impacts are comprehensive at this time, and many of the risks are difficult to estimate and value. ... In addition, the element of time in climate change impacts particularly complicates the valuation. ... Economists do not agree on the appropriate discount rate(s) to use for a multi-generational, largely non-market issue such as human-induced climate change.”). They contend that the IWG arbitrarily jettisoned the longstanding 7 percent discount rate and employed an entirely new spectrum going as low as 2.5 percent and even encouraging agencies to depart downward. Susan E. Dudley et al., *The Office of Management and Budget’s Draft 2010 Report to Congress on the Benefits and Costs of Federal Regulations*, at 12, GW Regulatory Studies Center, <https://bit.ly/3euQiCf> (“The 7 percent rate remains an appropriate estimate of the average before-tax rate of return to provide capital in the U.S. economy.”).

Commenter (0804-EDF et al) suggests that, while they agree with EPA’s conclusion that the 7% capital-based discount rate is inappropriate for climate effects, EPA should provide additional justification for its discount rate choices and conduct sensitivity analysis using discount rates lower than 2.5% - such as a 2% discount rate. The commenter states that, although OMB Circular A-4 (2003) provides discount rates of 3% and 7% as a default assumption, it also requires agency analysts to do more than rigidly apply default assumptions; Circular A-4 (2003) requires agencies to justify the choice of discount rates for each analysis. The commenter states that based on Circular A-4 (2003)’s criteria, there are numerous reasons why applying a 7% discount rate to climate effects that occur over a 300-year time horizon would be unjustifiable—and that discount rates of 3% or lower are appropriate. The commenter suggests that EPA could look to the “value of carbon” estimates from the New York State Department of Environmental Conservation (“DEC”), which applied a 2% discount rate as its central value. Pursuant to DEC’s estimates, at a discount rate of 2% social cost valuations for year 2020 emissions equal \$125 per ton of carbon dioxide, \$2,782 per ton of methane, and \$44,727 per ton of nitrous oxide. The commenter adds that the DEC also recommended using a 1% discount rate for climate impacts and provided annual social cost values for doing so. Because these valuations are based off the Working Group’s methodology, and differ only through the discount rate, the commenter suggests, EPA can apply these valuations if it applies additional sensitivity analysis around lower discount rates.

Further, the commenter (0804-EDF et al) contends that there are several reasons which support the use of the consumption rate of interest. First, the commenter states, the discount rate should be based on the consumption rate of interest (3%) not the private return to capital (7%) because climate change concerns public well-being broadly rather than market participants narrowly and mostly affects large-scale consumption, as opposed to capital investment. The commenter states that because SC-CH<sub>4</sub> is presented in consumption-equivalent units, OMB Circular A-4 (2003) in fact dictates application of consumption-based discount rates. Second, the commenter states, uncertainty over the long-time horizon for climate effects should result in the selection of a lower discount rate. Third, the commenter notes that the 7% discount rate ignores catastrophic risks and welfare of future generations – as EPA showed in a recent cost-benefit analysis, the 7% rate truncates the long right-hand tail of social costs relative to the 3% rate’s distribution, where the long right-hand tail represents the possibility of catastrophic damages. Fourth, the commenter states, long-term time horizons in general counsel strongly against application of a capital-based rate. Fifth, the commenter states, several standard justifications for capital-based discount rates break down given the threats of climate change. The commenter provides by way of example,



that one argument for capital-based discount rates is that spending capital on climate abatement policies has opportunity costs and so, in policy analysis, future costs and benefits should be discounted at the rate of return to capital. However, the irreversible, uncertain, and catastrophic risks of climate change may disrupt this “opportunity cost” rationale: while it may seem, for instance, that future, wealthier generations might have better opportunities to address climate change for themselves, irreversible or catastrophic damages could arise that make future mitigation efforts more expensive or impossible, according to the commenter. Sixth, the commenter asserts that the 7% discount rate is inappropriate because it is based on outdated data and diverges from the current economic consensus. The commenter reports that the Council of Economic Advisers (CEA) detailed recently that Circular A-4 (2003)’s guidance on discount rates needs an update.

Commenter (0804-EDF et al) also provides further argument as to why the 7% rate is too high – the market return on an oil and gas operation can externalize some of the costs of its pollution onto society. Especially when crafting long-term climate policies, the commenter states, it would be inappropriate to discount future welfare because the current generation of investors prefers the high market returns that are now available partly because of such externalities. Finally, the commenter states, OMB Circular A-4 (2003) recognizes that intergenerational contexts raise unique ethical issues that further counsel for lower discount rates as most market data reflects at best individual’s current preferences for their own welfare over time and so simply does not capture society’s preferences toward or ethical obligations to future generations. The commenter states that EO 13990 instructs agencies to ensure that the social cost of GHG values adequately account for “intergenerational equity” and a 7% rate ignores much of future generations’ welfare and so would be inconsistent with that mandate.<sup>137</sup>

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<sup>137</sup> Peter Howard & Jason A. Schwartz, *About Time: Recalibrating the Discount Rate for the Social Cost of Greenhouse Gases* (Policy Integrity Report 2021), [https://policyintegrity.org/files/publications/About\\_Time.pdf](https://policyintegrity.org/files/publications/About_Time.pdf); 2021 Vehicle Emissions Standards RIA; Maureen Cropper, *How Should Benefits and Costs Be Discounted in an Intergenerational Context?*, 183 RESOURCES 30, 33 (2013); Richard G. Newell & William A. Pizer, *Uncertain Discount Rates in Climate Policy Analysis*, 32 ENERGY POL’Y 519, 521 (2004); 2021 TSD, *supra* note 26; Nat’l Acad. Sci., Engineering & Med., *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide* 28 (2017), <https://www.nap.edu/read/24651/chapter/1> [hereinafter “NAS 2017 Report”]; Kenneth Arrow et al., *Is There a Role for Benefit-Cost Analysis in Environmental, Health, and Safety Regulation?*, 272 SCIENCE 221 (1996); Richard Newell, *Unpacking the Administration’s Revised Social Cost of Carbon* (Oct. 10, 2017), <http://www.rff.org/blog/2017/unpacking-administration-s-revised-social-cost-carbon>; Comments from Robert Pindyck, to BLM, on the Social Cost of Methane in the Proposed Suspension of the Waste Prevention Rule (submitted Nov. 5, 2017); OMB Circular A-4 (2003); see also Interagency Working Group on the Social Cost of Carbon, *Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2015), <https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf> [hereinafter *Response to Comments*]; Council of Econ. Advisers, *Discounting for Public Policy: Theory and Recent Evidence on the Merits of Updating the Discount Rate* at 9 [hereinafter *CEA Issue Brief*], [https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701\\_cea\\_discounting\\_issue\\_brief.pdf](https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf); NAS 2017 Report; EPA, *Benefit and Cost Analysis for Revisions to Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*; H.R. Rep. No. 95-294, 34, 1977 U.S.C.C.A.N. 1077, 1112; 2021 TSD, *supra* note 26; Qingran Li & William A. Pizer, *Use of the Consumption Discount Rate for Public Policy over the Distant Future*, 107 J. ENV’T ECON. & MGMT. 102,428 (2021); Richard L. Revesz & Matthew R. Shahabian, *Climate Change and Future Generations*, 84 S. CAL. L. REV. 1097 (2011); Exec. Order § 13,990 5(b)(ii)(E); N.Y. Dep’t of Env’t Conserv., *Establishing a Value of Carbon: Guidelines for Use by State Agencies* 16–18 (2020), [https://www.dec.ny.gov/docs/administration\\_pdf/vocguidrev.pdf](https://www.dec.ny.gov/docs/administration_pdf/vocguidrev.pdf); N.Y. Dep’t of Env’t Conserv., *Appendix: Value of Carbon* (2020), [https://www.dec.ny.gov/docs/administration\\_pdf/vocapprev.pdf](https://www.dec.ny.gov/docs/administration_pdf/vocapprev.pdf).

Commenter (0804-EDF, et. al.) also states EPA appears to have chosen to ensure that all climate benefits are discounted in an internally consistent way, by applying the same discount rate used to estimate the underlying social cost values (e.g., 2.5%, 3%, or 5%) to calculate the present values of future climate benefits, which follows the IWG's guidance. But, the commenter states, it also means EPA is calculating the present value of reduced GHG emissions differently than the present value of other costs and benefits (which, per Circular A-4 (2003)'s current default recommendations, are calculated at 3% and 7% discount rates). The commenter recommends that EPA expand on its justification to its current approach to discounting through two approaches: (1) explaining why a general focus on discounting all costs and benefits at consumption-based rates, rather than at a 7% capital-based rate, is appropriate in this particular rulemaking; and (2) further explaining why special legal, economic, and policy considerations justify a different approach to discounting climate effects as distinct from other costs and benefits. Further, the commenter recommends that EPA should consider working with OMB and the IWG to move toward a declining discount rate framework that can straightforwardly resolve all these issues of consistent discounting, by adopting a single schedule of applicable discount rates that steadily declines over time.<sup>138</sup>

Response I-20-18: In the Final RIA, monetized climate effects are presented under a 2 percent near-term Ramsey discount rate, consistent with the EPA's updated estimates of the SC-GHG. The 2003 version of OMB's Circular A-4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. While the Final RIA was being drafted and reviewed, OMB finalized an update to Circular A-4, in which it recommended the general application of a 2.0 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC-GHG estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A-4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC-GHG. See Section 3.2 of the Final RIA for more discussion.

In addition, a detailed response regarding the use of the consumption rate of interest and the omission of SC-GHG estimates using the 7% discount rate can be found in the Appendix of this RTC where responses are provided on comments pertaining to the EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

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<sup>138</sup> 2021 TSD, supra note 26; Howard & Schwartz, supra note 29; EPA, Guidelines for Economic Analysis; H.R. Rep. No. 95-294; 1977 U.S.C.C.A.N. 1077; Howard & Schwartz, supra note 29; 42 U.S.C. § 4332(1); 42 U.S.C. § 4331(b)(1); Exec. Order No. 13,563 at 1(c); Exec. Order No. 13,990 at 5(b)(ii)(E) & (iii); NAS 2017 Report, supra note 292010; Zero Zone, Inc., 832 F.3d; Arden Rowell, Time in Cost-Benefit Analysis, 4 U.C. IRVINE L. REV. 1215 (2014).

#### 20.2.4 Criteria and HAP Pollutant Benefits Analysis

Comment: Commenter (0842- NYU School of Law) states that the EPA declines to monetize several benefits that the Proposed Rule would yield, including the benefits of reducing VOC and hazardous air pollutant (HAP) emissions. The commenter notes that the 2021 November proposal RIA does report how many tons of each pollutant its proposed standards would abate, but it does not assign any monetary value to such figures.<sup>139</sup> As a result, the commenter contends that the EPA’s estimate of total monetized benefits understates the health and environmental gains from the rule.

The commenter (0842-NYU School of Law) states that the EPA discusses two categories of benefits associated with reducing VOC emissions: those related to ozone and those related to fine particulate matter (PM<sub>2.5</sub>).<sup>140</sup> The commenter notes that the EPA claims it cannot monetize ozone-related benefits because underlying data are too spatially coarse to derive meaningful estimates.<sup>141</sup> The commenter adds that the EPA then claims that it cannot monetize PM<sub>2.5</sub>-related benefits because “it is unlikely that the VOC emissions reductions projected to occur under this proposal would have a large contribution to ambient secondary organic carbon aerosols.”<sup>142</sup>

Yet, the commenter (0842-NYU School of Law) suggests that, in prior analyses of its regulations of the oil and gas sector, EPA has monetized the value of VOC reductions. For instance, the commenter states that, in an RIA for a 2016 rule related to methane in the oil and gas sector (the 2016 Rule), EPA presented a range of epidemiology studies estimating the value of reducing a ton of VOC in 2012 dollars: \$300 to \$7,500.<sup>143</sup> According to the commenter, even conservatively presenting results at the low end of that range—say, \$300, updated for inflation—would yield a more comprehensive picture of the benefits of EPA’s proposed standards. Put differently, they state that it would better capture the fact that, while there may be “a range of values” for VOC emission-reduction benefits, that value “is certainly not zero.”<sup>144</sup>

Commenter (0842- NYU School of Law) provides that the EPA claims that, “[w]ith the data available, it was not possible to estimate the change in emissions of each individual HAP,” and that “methodology and data limitations” preclude “monetize[ing] the health benefits of reductions in HAP.”<sup>145</sup> As with VOCs, the commenter recommends that the EPA present any quantitative information available to it, even if incomplete or uncertain.<sup>146</sup>

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<sup>139</sup> 2021 NSPS OOOOb and EG OOOOc RIA (2021 PRIA). at 5-8 tbl.5-4 (estimating that EPA’s “Primary Proposal” would abate 12,000,000 short tons of VOC emissions and 480,000 short tons of HAP emissions).

<sup>140</sup> Id. at 3-4 (“VOC emissions are precursors to secondary formation of PM<sub>2.5</sub> and ozone on a broader regional scale.”).

<sup>141</sup> Id. at 3-16 to -17.

<sup>142</sup> Id. at 3-19.

<sup>143</sup> See EPA, Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources 4-22 (2016), <https://perma.cc/5LY4-KFXL>.

<sup>144</sup> *Ctr. for Biological Diversity v. Nat’l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2008)

<sup>145</sup> 2021 PRIA, *supra* note 3, at 3-22.

<sup>146</sup> Circular A-4 (2003), *supra* note 34, at 27 (“If you are not able to quantify the effects, you should present any relevant quantitative information along with a description of the unquantified effects[.]”)



Two other commenters (0844-EDF et al, 0828-UCS) suggest that the EPA quantify and monetize the Proposal's non-climate health benefits. Commenter (0844-EDF et al) states that the EPA has not attempted to monetize the proposal's non-climate health impacts, so those significant benefits are left out of the calculations of net benefits for the regulatory options. The commenter recommends that EPA consider and account for, in as much detail as possible, the many significant non-climate health benefits of the proposal. Wherever possible, they suggest that health benefits be quantified and monetized. In cases of high levels of uncertainty, they suggest that the EPA quantify and monetize these benefits using conservative estimates rather than not monetizing or quantifying them at all (which is the agency's current approach) and should present them alongside a discussion of any limitations in the analysis. To the extent that the EPA is truly unable to monetize the proposal's non-climate health impacts, the commenter stresses that it must emphasize that the EPA's 2021 November proposal RIA underestimates the overall benefits of the proposal as a result.

Commenter (0844-EDF et al) recommends that the EPA seek to connect the reduced emissions of methane, VOCs, and HAPs to actual health outcomes. The commenter explains that they believe that some measure of the anticipated improvement in public health outcomes should be included, even if that figure represents the lower bound of the estimates or the minimum anticipated benefit. The commenter contends that including such a figure would allow for a better comparison of the costs and benefits of the four regulatory options.

The commenter (0844-EDF et al) refers to a table (Table 3-1 of their comment letter) that lists the currently unquantified health benefits of the proposal's projected emissions reductions, including various measurable health outcomes. According to this table, the commenter notes that the proposal would reduce premature mortality from short-term and long-term exposure to ozone and PM<sub>2.5</sub>, infant mortality, hospital admissions and emergency department visits, heart attacks, strokes, asthma onset and symptoms, allergic symptoms, minor restricted-activity days, school absence days, decreased outdoor worker productivity days, and morbidity from exposure to HAPs. The commenter appreciates the EPA's tabulation of the beneficial health outcomes of reducing methane, VOC, and HAP emissions, and urges the agency to quantify, to the greatest extent possible, the known health impacts of these emissions and the benefits of reducing these emissions.

The commenter (0844-EDF et al) adds that quantifying and monetizing the proposal's health benefits would also help to strengthen the EPA's environmental justice analysis. In the absence of quantified and monetized data on health impacts, the commenter states that environmental justice analysis currently fails to capture the full panoply of benefits that the proposal would afford if finalized. The commenter suggests that, by quantifying and monetizing the local and regional benefits of reduced methane, VOC, and HAP emissions, the EPA would be able to perform a more robust assessment of the proposal's environmental justice impacts.

The commenter (0844-EDF et al) mentions that the EPA includes an "illustrative screening analysis" in which it monetizes VOC-related ozone health benefits. The commenter urges the EPA to perform analogous supplemental analyses that monetize HAP-related health benefits, as well as all other benefits that are currently unmonetized. Particularly if the EPA intends to keep

these analyses as supplemental and outside the overall benefits calculation, we urge the agency to present the results even if they are associated with higher levels of uncertainty.

Although completing additional similar supplemental analyses would strengthen the EPA's assessment of the proposal's health benefits, the commenter (0844-EDF et al) recommends that EPA also reconsider its decision to leave the non-climate health benefits unmonetized in its overall benefit calculations. According to the commenter, the EPA does not adequately explain why it cannot incorporate this analysis in some fashion into the proposal's monetized benefits. The commenter provides that the RIA's discussion of the illustrative screening acknowledges the uncertainties associated with that approach. However, given that the EPA found the state of the science certain enough to perform this analysis, the commenter suggests that the EPA consider more broadly incorporating these benefit estimates into the overall benefits summary or explain why it has chosen not to do so. In other words, the commenter believes that the EPA can conclude that the proposed rule will have at least a certain dollar benefit in terms of health benefits derived from reductions in VOC emissions and corresponding estimated reductions in premature mortality and illnesses, such as those in Table B-3 of Appendix B. The commenter suggests that EPA add those estimates to the tables summarizing the proposal's benefits.

Additionally, the commenter (0844-EDF et al) notes that the current state of the data and available modeling methods supports quantifying and monetizing the proposal's health benefits. There is a body of peer-reviewed studies that quantify reduced mortality and morbidity and/or monetize health benefits of various emission-reduction scenarios in the U.S., including some that have used the community edition of the EPA's Environmental Benefits Mapping and Analysis Program (BenMAP-CE). The commenter recommends that the EPA use the available modeling methods to the greatest extent feasible.

Response I-20-19: The EPA has updated the analysis in the RIA for the final rule which now includes monetized ozone benefits from VOC emissions reductions. This provides quantified benefits for one source of previously unquantified non-climate benefits. We are currently unable to estimate or monetize the impact of changes in HAP releases due to data limitations, most notably the lack of sufficient emission location specificity to perform such analyses. The HAP impacts available in EPA's 2017 AirToxScreen dataset are provided for the entire oil and natural gas sector, which includes sources outside the scope of this regulation. We do not have current modeling of HAP impacts specific to only the sources subject to the regulation; therefore, we cannot estimate risks, including any reductions, solely attributed to the source category. Furthermore, more refined emissions data would be needed to conduct an assessment at the census block level, where we could draw more accurate conclusions about the human health risks.

Comment: Commenter (0581-NACAA) notes, with regards to criteria pollutants, that the anticipated reductions in ozone precursors as a result of the 2021 November proposal would help state and local agencies in their efforts to achieve and maintain compliance with the National Ambient Air Quality Standards (NAAQS). The commenter states that the EPA says its 2021 November proposed rule would reduce an estimated 12 million tons of VOCs from 2023 to 2035. According to the commenter, this will be particularly important as more areas face reclassification under the 2015 ozone standards. Moreover, they note that one predicted outcome

of increased anthropogenic climate change is longer and more harmful ozone seasons. This may mean greater effort will be needed by states and localities to meet and maintain compliance with the ozone NAAQS. In addition to significant local benefits from lower VOC emissions that might be reasonably anticipated in areas with high amounts of oil and natural gas sector activity, the commenter states that these reduced emissions will also reduce impacts from air pollution transported across state lines, which raise complex challenges for downwind states.

Commenter (0581-NACAA) provides that oil and gas operations also emit other criteria pollutants such as sulfur dioxide and nitrogen oxides, as well as air toxics including benzene, formaldehyde, toluene, ethylbenzene and xylene. EPA says that its 2021 November proposed rule would reduce 480,000 tons of air toxic pollutants from 2023 to 2035. NACAA endorses and welcomes these potential pollution reductions. EPA also states that its 2021 November proposal would reduce 41 million tons of methane emissions from the oil and natural gas industry between 2023 and 2035. The commenter asserts that these methane reductions should not only reduce harms and offer public health protections on a local basis but on a global one; they would help address the ongoing crisis facing the planet's climate. While not a criteria pollutant covered by the NAAQS, methane remains a potent climate pollutant with a global warming potential nearly 30 times that of CO<sub>2</sub>. Restoring the methane NSPS advances the agency's legal obligation to limit methane emissions from existing oil and natural gas sector sources.

Response I-20-20: The analysis in the RIA for the final rule has been updated to quantify monetized ozone benefits resulting from changes in VOC releases. This information can be found in Section 3 of the RIA. The EPA is currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations, most notably the lack of sufficient emission location specificity to perform such analyses. The HAP impacts available in EPA's 2017 AirToxScreen dataset are provided for the entire oil and natural gas sector, which includes sources outside the scope of this regulation. The EPA does not have current modeling of HAP impacts specific to only the sources subject to the regulation; therefore, the EPA cannot estimate risks, including any reductions, solely attributed to the source category. Furthermore, more refined emissions data would be needed to conduct an assessment at the census block level, where the EPA could draw more accurate conclusions about the human health risks.

## ***20.2.5 Economic Impacts***

### **20.2.5.1 State Resource Funds-Royalties**

Comment: Commenters (0411- REM, 0431-NOI, 1300-PLS) state that the revenue from states of Michigan and Montana-owned wells go into state resource funds (i.e., Michigan Natural Resources Trust Fund, State of Michigan, State of Montana's General Fund). The commenters complain that plugging wells earlier in their life would deprive the Funds of revenue which would cause irreparable harm to the Trust Fund. Commenter (0411-REM) specifically states that plugging wells earlier in their life will also lead to less state [Michigan] revenues, not only for production taxes, but also for royalties paid to private landowners and the State of Michigan (the State of Michigan is the largest royalty holder in Michigan).

Commenter (0597-IOGA) notes that high compliance costs could lead to the potential for oil and gas wells to be prematurely plugged which would impact royalty payments that have been received for decades and are relied upon by Indiana residents for living expenses.

Response I-20-21: The EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. The EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. With the available data and the complexity described, the EPA cannot estimate the impacts of the final regulation on the owners or operators of marginal wells. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and therefore the impact of lost royalties and state revenue would be minimal.

#### 20.2.5.2 State Economic Impacts

Comment: Several commenters provide comment on the state impacts that they anticipate because of the 2021 November proposal. Some of the specific comments received are provided in the following paragraphs.

Commenter (0763-TCEQ) believes that the EPA has underestimated the overall number of affected facilities. As an example, they state that defining oil wells with associated gas as an affected facility and requiring these sources to route gas to a sales line, use the gas at the site, or route the gas to a control device could require the submittal of at least 100,000 projects for new or modified sites to the State. They add that it is not typical that production wells will always be drilled in areas where a pipeline exists or is readily available at the time of drilling. The commenter asserts that the implementation of the 2021 November proposed rules will dramatically increase the fiscal burden on Texas and will likely adversely affect other states across the nation with similar oil and gas production activities and facilities.

The commenter (0763-TCEQ) adds that the EPA's RIA should include the curtailment of economic and societal benefits generated by oil and gas production that will occur because of this rulemaking. In Texas this includes impacts to school districts, veterans, and universities that rely on oil and gas production revenue. They add that there will be an overall impact to state government budgets and revenue, including the Texas Economic Stabilization Fund ("Rainy Day" Fund). According to the commenter, this will have a significant impact on delivery of state services to citizens and local communities.

Commenter (0800-UPLP) is concerned that the cost of implementing said measures may do much to harm the oil and gas industry's resilience in the state [Utah]. Compliance would require oil and gas operators to retrofit and update existing infrastructure to standards at costs which have not yet been fully quantified. Not only would the compliance costs be passed down to the producers, but so would the increased cost of product recovery. Thus, while the net benefits may be somewhat equitably distributed, the costs would be unevenly borne by the states and oil and gas operators. The commenter states that the 2021 November proposal does not seem to contemplate that, due to the added costs associated with compliance (again imposed on the oil

and gas operators), many oil and gas sources would become uneconomical to extract and would instead leave tons of natural gas stranded and unproduced. While the commenter notes that the state [Utah] is supportive of finding innovative ways to reduce air pollution and methane emissions, they assert that it must be done in a way that equitably allocates costs and benefits, and without jeopardizing the resilience of the state's [Utah's] oil and gas industry.

Commenter (0946-MOGA) reports that they conducted an analysis of variable operational costs which included seasonal variation in requirements pertaining to snowfall, temperatures, travel restrictions, formation dynamics, operational agendas, resource recovery costs, land-owner contracts, royalties, etc. The analysis notes remaining reserves, annual decline rate, production life, operating costs, and analyzes potential gross revenue over remaining well life, before and after regulation. The commenter states that the results of their analysis include an estimated loss of \$2,514 per well. They report that this economic loss is driven solely by future proposed regulations outlined in NSPS OOOO(b) and EG OOOO(c) and would lead to early plugging of wells and waste of State of Michigan resources. The commenter (MOGA) views the proposed regulations under NSPS OOOO(b) and EG OOOO(c) as short-sighted, wasteful, and having a significant impact on the State of Michigan's natural resources, small businesses, and economic climate.

Similarly, commenter (0411-REM) states that the overall effect of forcing additional capital expenditures on marginal wells will force a certain percentage of wells to be plugged due to a lack of economic payout. The result will be less oil and gas on the free market, resulting in eventual price increases to consumers. It will also result in a loss of good paying jobs [in Michigan] as well counts decline and workers are laid off.

Commenter (0910-AGKY) states that setting EGs for methane GHGs represents a stark departure from decades of EPA practice. The commenter notes that the EPA's previous approach of nonregulation avoided harm to Louisiana, allowed the State to invest heavily in natural gas, and influenced the State's policy. The commenter adds that the 2021 November proposal also upsets decades of settled reliance on the EPA's prior approach of not setting a nationwide EG standard. The commenter provides that Louisiana has structured its energy priorities around natural gas, which has in turn become a driver of the state's economy and tax base. Specifically, the commenter reports that Louisiana is one of the top five states in both natural gas production and reserves and accounts for about 9% of U.S. production and 8% of U.S. reserves. And the industry accounted for almost \$4.5 billion of State and local tax revenue—a whopping 14.6% of all state taxes, licenses, and fees collected. They contend that the 2021 November proposal will impose harm on rural Louisiana areas. For example, the commenter explains that the natural gas industry is the lifeblood of the renewal of impoverished areas such as DeSoto Parish and industry makes up 7 percent of all local property tax for Cameron Parish. In addition, they add that it will cost the State of Louisiana tens of millions to implement; potentially require hundreds or even thousands of new state employees around the country; and could also potentially lead to backlogs for existing pipeline infrastructure maintenance creating serious environmental risks and undermining the integrity of the energy grid.

Commenter (0910-AGKY) expresses that the EPA nowhere acknowledges these harms or Louisiana's and industry's reliance on the current regime. Given these substantial reliance interests, a national standard would require an extensive analysis of its effect on Louisiana and

other co-signing states. The commenter suggests that the agency has a duty to explain why it deemed it necessary to overrule its previous position on which decades of reliance has been built, however, they complain that no discussion is provided in the 2021 November proposal.

Conversely, commenter (1302-WOC) believes that direct methane regulation will encourage technological innovation and help grow Wyoming's economy around methane mitigation in the long run. The commenter estimates that there are approximately 13 businesses across Wyoming working in the methane emission mitigation industry.<sup>147</sup> Some of these businesses manufacture equipment needed for leak detection and repair work, while others are more focused on consulting and compliance services.

The commenter (1302-WOC) applauds the efforts of this new rule to encourage responsible stewardship of non-renewable resources for taxpayer benefit. Regulating waste methane from new and existing sources will help ensure that Wyomingites are fairly compensated for the extraction and use of non-renewable resources.

The commenter (1302-WOC) and its partners estimated that in 2018, Wyoming lost an estimated annual \$51 million to \$96 million worth of natural gas due to intentional flaring, venting and careless leaks. This translated to \$8.8 -16.1 million lost in annual royalty payments to the state. Of this amount, \$3.4 million to \$6.5 million was lost ad valorem revenue (property tax that goes directly to counties) that could have gone to the purchase of emergency equipment, or road and bridge repair, or human services like public health nurses and libraries.<sup>148</sup> The commenter states that these are critical revenue streams that taxpayers and budget strapped communities deserve to see for the depletion of natural resources, particularly given ongoing statewide budget cuts.

Response I-20-22: The EPA disagrees with commenters' assertions that the rule will have significant negative impacts on production levels or on oil and natural gas prices. The EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. The EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively. Notably, none of the commenters provide specific data or analysis to support general claims of production and price impacts at the state or national level.

Likewise, the EPA disagrees with commenters' assertions that the rule would have a significant negative impact on state economies and budgets. In addition to the sectoral analysis described above that found limited impact to national levels of production or prices, the EPA also developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. The EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. With the available data and the complexity described, the EPA cannot estimate the impacts of the final regulation on the owners or operators of marginal wells. Moreover, To the extent that any marginal wells might be plugged in relation to anything

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<sup>147</sup> Environmental Defense Fund. Methane Fact Sheet for Wyoming Methane Economy. 2021 Report.

<sup>148</sup> Wyoming Outdoor Council. 2018 Oil and Gas Waste Report.

contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and therefore the impact of lost royalties and state revenue would be minimal. In addition, as one commenter (1302-WOC) points out, several elements of the rule are expected to have positive impacts on royalty payments and ad valorem tax revenue by encouraging additional capture of natural gas. As such, EPA believes the claims of significant social costs borne by state governments and related entities (schools, universities, etc.) are overstated by commenters.

In response to one commenter (0946-MOGA), EPA disagrees that the “*economic loss is driven solely by future proposed regulations outlined in Subpart OOOO(b) and Subpart OOOO(c) and would lead to early plugging of wells...*” and notes that the profit or loss of the cited well is determined by the variability of oil prices and the assumption that the cited well has 1,200 barrels of oil reserves. At the September 2023 monthly average WTI price of \$89.43, the commenter’s cited well would earn a profit of \$24,390 over 15-years based on the commenter’s assumptions. A larger amount of oil reserves would also increase the earnings from the cited well.

In response to one commenter’s (0763-TCEQ) claim that EPA has underestimated the number of affected facilities, using associated gas as an example, EPA notes that its estimates of associated gas affected facilities, presented in Table 2-5 of the Final RIA, are based on data from the Greenhouse Gas Reporting Program (GHGRP). The commenter does not provide sufficient information to assess the validity of its claim, for associated gas or any other affected facility type.

Comment: Commenters (0929-NSWA, 0585-KOGA) note that historically, operators surrender their wells to state agencies to complete remediation of the unplugged wells at the time that the operator ceases to do business. The commenters are concerned that the EPA’s additional regulations will add enough cost to wells that are marginally profitable (i.e. low production wells) that the operators will decide to terminate their business, leading to many more wells being surrendered to state agencies. While operators are required to maintain bonding for each well, in the event that this occurs, funds from the surrendered bonds are often not utilized to plug the operator’s remaining wells. As a result, the taxpayers ultimately pay to plug the wells.

Response I-20-23: EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To mitigate the impact of orphaned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s).

To maintain transparency for the responsible owner or operator and prevent well sites from becoming orphaned, EPA is finalizing the rule with a well closure plan requirement which

requires fugitive monitoring of well sites for the life of the well and can only be discontinued if the well site is properly plugged and an OGI survey is done to ensure there are no emissions from the site. EPA is also requiring owners and operators to submit, through an annual ownership report, changes in ownership at individual well sites so it is clear who the responsible owners and operators are until the site is plugged and closed and fugitive emissions monitoring is no longer required.

#### 20.2.5.3 Tribal Economic Impacts

Comment: Commenter (1301-NATBC) expresses concern regarding the cost of implementation and potential direct and indirect economic effects. Specifically, commenter is concerned that the 2021 November Proposed Rule would directly and significantly impact the Northern Arapaho Tribe. Oil and natural gas extraction is a substantial presence on the Wind River Reservation and has an important role in the Tribe's economic wellbeing. The Northern Arapaho Tribe, in co-tenancy with the Eastern Shoshone Tribe, owns or leases oil and gas operations within the Reservation. In 2021, the Tribes assumed control of the largest oil field on the Reservation, Circle Ridge Field, which accounts for about 60 percent of the oil produced on the Reservation. Revenue from petroleum and natural gas production sustains their people economically, funds many aspects of Tribal government and services, and based on royalties enables per capital payments which are relied upon by the Tribe's members for daily necessities.

Commenter (0794-MHAN) states that in promulgating regulations that will have far-reaching implications for the oil and gas industry, which is known to operate on tribal lands, the EPA must consider how those regulations may interfere with tribal treaty rights. Commenter asserts that if the EPA were to finalize regulations that unreasonably restrict or burden development of tribal oil and gas resources, these regulations would interfere with the MHA Nation's treaty-protected right to engage in trade. More specifically, commenter notes, under Article 5 of the 1825 Treaties between the United States and the MHA Nation, the federal government agreed "to admit and license traders to hold intercourse with said tribe, under mild and equitable regulations ..." (citing Treaty with the Arikara, 7 Stat. 259 (July 1825); Treaty with the Mandan, 7 Stat. 264 (July 1825); Treaty with the Hidatsa, 7 Stat. 261 (July 1825)). Commenter states that in promulgating its methane regulations for the oil and gas industry EPA must adequately consider tribal treaty rights – national requirements that would unduly or inequitably burden development of tribal resources cannot be considered "mild and equitable." Commenter asserts that EPA's forthcoming regulations should be appropriately tailored to provide for cost effective emissions reductions while still providing for continued oil and gas development on the Fort Berthold Reservation.

Response I-20-24: Regarding concerns about cost of implementation, please see the Final Rule preamble at Section VIII.B for a discussion of how the EPA considered control costs in development of the Final Rule.

Regarding the issue of tribal treaty rights raised by the commenter, the EPA notes that commenter does not argue that the Proposed Rule would, in fact, interfere with tribal treaty rights or that it would unduly or inequitably burden the development of tribal resources. Nor does it explain with specificity how the Proposed Rule would interfere with tribal treaty rights. Nonetheless, the EPA acknowledges the commenter's concerns. As stated in the Final Rule at



Section XVI.F, the EPA acknowledges that this rule will have certain tribal implications. In accordance with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will continue to consult with tribal officials and engage with tribes on a government-to-government basis as these rules become implemented. The EPA encourages tribes to meaningfully engage with the agency in these processes. Please see Section XVI.F for more detail regarding the EPA's consideration of tribal implications and EPA's consultation with tribes in relation to this rulemaking.

### ***20.2.6 Energy Impacts***

Comment: Several commenters express concern that the 2021 November proposed rule will result in decreased domestic oil and natural gas production. Some of the specific representative comments received are provided in the following paragraphs.

Commenter (0334-GOAWV) recommends that the rules recognize the critical role that oil and gas plays in meeting the nation's energy and environmental needs. According to the commenter, the final rules must have a pathway to reasonable and cost-effective compliance. The commenter asserts that U.S. produced oil, natural gas and natural gas liquids are critical to providing affordable, clean energy to heat and power millions of American homes and businesses, fueling manufacturers, including the production of personal protective equipment (PPE), medicines and medical equipment, and providing for enhanced national security.

Commenter (0793-PBPA) notes that the EPA estimates the 2021 November proposed rule will result in a reduced domestic production of 12.2 million barrels per year.<sup>149</sup> Based on the commenter's analysis of the cost of the 2021 November proposed rule, the actual operators that will be impacted, and the economic realities in the oilfield, the actual reduction in domestic production will be significantly higher than estimated by the EPA. The commenter recommends that EPA not make rules without investigating the scope and effect of what those rules will be, especially rules that will impact hundreds of thousands of sites. They add that the impacts could have a significant effect on domestic energy prices as well as drive a significant number of oil wells into uneconomic territory.

Commenter (0822-TAEP) states that the EPA acknowledges that the initial proposal costs could result in notable consequences to production in the U.S. The commenter notes that an overreach in regulation could have profound negative consequences to increasing emissions globally by reducing domestic production and forcing domestic and global demand to rely more on sources of oil and natural gas from producing countries with lower environmental and labor standards. The commenter urges EPA to undertake a robust analysis to determine if the global harm to any shift in production overseas would result in more pollution, and the extent to which the advantages of domestic production and the benefits derived from that production far outweigh any negative externalities from pollution by an overseas competitor. The commenter believes that the EPA's mandate to protect human health and the environment while tackling the climate crisis at home and abroad necessitates a higher level of review than what is currently contemplated in this proposal. The commenter adds that this analysis should by no means be limited to oil and natural gas as numerous industrial processes and manufacturing have been

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<sup>149</sup> 86 Fed. Reg. at 63,258.

exported overseas but the extent to which the EPA is contemplating new regulations on oil and natural gas production, they urge it to start there.

Similarly, commenter (0743-WEA) contends that certain provisions in the rule would render large swaths of production in the U.S. uneconomic to continue to operate, which will only further constrain domestic supply and force domestic energy users to be more dependent on oil produced overseas, where the EPA's jurisdiction doesn't extend. The commenter adds that creating rules that force the shutting in of wells in the U.S. to instead ship more oil across the ocean from less regulated countries ultimately increases global GHG emissions and introduces negative externalities that the EPA has seemingly ignored in the development of this rulemaking.

Commenter (0431-NOI) notes that if it is assumed that stripper wells produce approximately 10 barrels of crude oil (bbl)/day that would mean over 7 Million bbl would be taken out of U.S. production. According to the commenter, since the U.S. utilizes or has a current demand of approximately 19.8 Million barrels per day (bpd) that would essentially put the U.S. in a severe bind to make up the lost 7 Million barrels. The commenter does not believe other countries could or would make up those volumes but rather would benefit from the rise in prices to over \$15 per barrel and cause gasoline to rise to perhaps \$11 per gallon, if that lost supply even becomes available to make gasoline or jet fuel.

Commenter (0595-Consumer Energy Alliance) agrees it is important to prioritize emission impacts during rulemaking. However, these decisions must also consider the significant progress that has already been made, and carefully consider the economic welfare of families and businesses nationwide. Affordable energy and environmental stewardship are important to all Americans.

Response I-20-25: The EPA disagrees with commenters' assertions that the regulation would have profound impacts on domestic oil and natural gas production. Several commenters assert severe impacts but fail to provide specific information to support those claims. The EPA models the impact of the rule on oil and natural gas supply in Section 4.1 of the Final RIA. The EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively. Further, the EPA disagrees with the commenters assertion that this regulation will remove 7 million barrels of oil per day from U. S. production. The EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. The EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry.

We estimate that the change in oil imports would be an increase of 0.52% or less but are unable to quantify the impact on GHG emissions of changes in imports. However, the relatively small estimated increase in imports suggests that the net effect on GHG emissions will be negligible.

Comment: Commenter (0922-NAM) opines that any well-tailored NSPS rule should not drive an unnecessary increase in oil, natural gas, or electricity costs, noting that affordable and reliable

electricity provides domestic manufacturers a competitive advantage in the global economy. Commenter believes that any efforts to develop new rulemakings should take great care to avoid measures that would raise the cost of electricity for consumers and businesses and threaten that important economic advantage manufacturers enjoy.

Response I-20-26: The EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.75% and 0.33%, respectively. We do not formally model the impact on electricity prices. We anticipate that in settings in which oil or natural gas electricity generating units are marginal electricity generators, the impact on electricity prices would be comparable, while in settings in which other energy sources are the marginal electricity generating units, the impact would be smaller.

### ***20.2.7 Impact on Small Business***

Comment: A prevailing concern from numerous commenters (0193-NFIB, 0411-REM, 0424-WV DEPDAQ, 0431-NOI, 0464-MOPC, 0465-JDC, 0425-Darrah, 0577-KIOGA, 0585-KOGA, 0597-IOGA, 0749-PAW, 0763-TCEQ, 0778-USCongress, 0793-PBPA, 0824-WDEQ 0923-Lambda, 0924-USSBA, 0929-NSWA, 0946-MOGA, 1155-Bean Ridge Resources, 1300-PLS, 1341-Conventional Groups, 1380-MOGA, 1381-MPA, 1422-U.S. Congress) is that the new requirements and regulatory costs of the proposed rule will have a significant and disproportionate economic and employment impact on small business, individual and farmers and independent operators and owners of marginal/low production and stripper wells and they recommend that these wells be exempt from the proposed rules. The compliance costs are perceived to have the potential to cause a premature, landslide plugging of wells. According to some commenters, this shut-in of wells is anticipated to result in a significant decrease in production of oil and natural gas which will particularly impact small, rural communities that rely not only on the employment, revenues, royalties from that production but also on the natural gas produced and used locally. The commenters collectively note a common concern that the EPA has overestimated the cost-effectiveness of the measures proposed as BSER and underestimated the significant impact this rule will have on small businesses. Some of the comments received state that while there are some concessions for smaller producers, the proposed regulations could put extreme financial burdens on them and puts small businesses at a significant disadvantage. Commenters add that this particularly applies to individual homeowners, farmers, or companies with very few employees such as family limited partnerships who are owners/operators of wells.

As a specific example, commenter (0946-MOGA) notes the proposed NSPS and EG regulations would potentially burden Michigan's small business marginal well producers with significant costs to achieve less than the maximum resource recovery, which they say directly contradicts the State of Michigan's laws regarding waste of state resources. The commenter reports that the State of Michigan views early plugging and abandonment of wells with remaining production horizons as waste. Part 615 of the state's regulatory framework stipulates the minimization of waste by efficiently managing operational endeavors to achieve maximum resource recovery. The commenter adds that many of Michigan's small entity producers facilitate this mandate by minimizing operational costs, negotiating production contracts, adjusting operational production schedules, and minimizing all costs when available. As such, the commenter reports that

Michigan's small entity and small business producers require flexibility to meet the State of Michigan's objective to maximize resource recovery.

Several commenters (0424-WV DEQDAQ, 0431-NOI, 0577-KIOGA, 0597-IOGA, 0924-USSBA, 1341-Conventional Groups) also state that there are unique aspects of small business that the EPA did not consider in the development of the cost/benefit analysis for the proposed regulation. Some of the specific comments provided include:

- American businesses of every size cannot get the employees they need to grow their business because the U.S. labor force has millions fewer workers available than it had in 2019.<sup>150</sup>
- American businesses of every size cannot get on time the goods and materials they need, because their supply chains have failed.
- American businesses of every size must pay more for the goods and materials they buy, and the fuel, electricity, and other sources or forms of energy they need to operate, as inflation roars
- The regulations require the purchase and installation of new equipment; however, they are last in line with suppliers. They also believe that they pay more per unit because they are generally purchasing fewer identical items and require more customization per installation. Commenter (0431-NOI) notes that if the proposed regulations are adopted in their current condition, they are finding that the equipment needed for compliance is not available and probably would have limited availability for 2 to 3 years because of supply issues.
- Many individuals do not have the knowledge to perform a fugitive emissions survey or to perform air emissions calculations for a well that has existed perhaps for multiple generations on their land.
- There is no available trained workforce to handle or install the equipment needed. Commenter (0924-USSBA) states that generally, for similar sets of regulatory requirements, small businesses face a greater cost of compliance. For example, they note that when a new regulation requires additional human resources, identifying, hiring, and retaining employees becomes a major concern for small entities, especially in the current tight labor environment. The commenter states that, according to the U.S. Census Small Business Pulse Survey, the number one concern of surveyed small businesses is the difficulty finding and hiring staff. The commenter further states that small businesses frequently lack the benefits packages larger businesses have (quality of healthcare, and other benefits) leaving smaller businesses at a disadvantage when hiring compliance staff.
- Smaller producers do not have the same economies of scale as larger producers and cannot spread increases in fixed compliance costs over as many projects.

Several commenters (0924-USSBA, 0597 IOGA, 1341-Conventional Groups) suggest that several factors have led the EPA to overestimate the cost-effectiveness of the measures proposed as BSER and underestimate the significant impact this rule will have on small businesses. Notably, the commenters note that these impacts extend beyond the impacts on small businesses the EPA considered under the RFA.

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<sup>150</sup> Federal Reserve Bank of St. Louis, Civilian Labor Force Level (CLF160V), available at <https://fred.stlouisfed.org/series/CLF160W> (visited November 16, 2021) (size of labor force in 2019 and 2021).

- The impacts are likely more severe for small businesses that own and operate existing sources not previously subject to the EPA regulation, particularly for those requirements that will require retrofitting equipment.
- The use of a single average annual number to represent entire sectors of the industry puts small businesses at a significant disadvantage compared to large businesses.
- The model plants the EPA uses to perform its BSER evaluations are very different from, and do not represent, the extremely small well sites and associated facilities owned and operated by their members. For example, the commenter states that primarily low-producing stripper wells, or "marginal wells," operated by members of the Conventional Groups generate far less revenue than large unconventional wells and therefore, operate on a much smaller return on investment from conventional wells.
- Annual averaging puts small businesses at a disadvantage. Small businesses generally cannot finance capital equipment over the time horizons used in the EPA estimates.
- The EPA distorts the financial outlook for small businesses by presenting cost savings from regulatory requirements as a simple subtraction from the annualized costs.

Several commenters (0411-REM, 1341-Conventional Groups, 0824-WDEQ, 0577-KIOGA, 0431-NOI, 0924-USSBA) contend that the EPA must perform small business-specific cost evaluation for all sources under the proposed rule using a more granular approach to the cost-effectiveness analysis. Specific comments include the following:

- Commenters contend that the analysis lacks transparency to uncover how it impacts various sizes of entities whether smaller, more vulnerable entities are disproportionately impacted by a regulation. For example, commenter (0924-USSBA) notes that while the size standard for the crude petroleum extraction industry (NAICS 211120) is 1,250 employees, 70 percent of firms in this industry have 5 employees or fewer. Those with 5 employees or fewer have an average revenue of \$769,000 in an industry with extremely high fixed costs. Due to this vulnerability, Advocacy recommends comparing the cost of the regulation not by the average of an entire NAICS code, but rather by different size categories within each NAICS code.<sup>151</sup>
- Commenters recommend that the EPA present an analysis of the economic impacts this rule would have on small businesses that own or operate existing sources which would be required to retrofit equipment under the EG OOOOc As these are typically older producing sites, commenter (0924-USSBA) states that they generally have much lower production than new sources, so there would be less revenue per unit across which to spread regulatory costs.
- Update of costs with details supporting. Commenters (0431-NOI, 0824-WDEQ) note they find that the estimated costs are understated. Commenter (0431-NOI) states that the 2016 EPA estimated one-time initial cost and estimated on-going annual costs for compliance are very low compared to what we the commenter is getting back from their contractors for this work. However, their costs are 2021 or 2022 estimates and the commenter states that it appears that EPA has not accounted for inflation of the compliance costs that have had a remarkable increase in 2021 (which will continue in 2022 according to their suppliers).
- Commenter (0824-WDEQ) suggests that particular attention be applied to the cost associated with monitoring surveys outlined in Section 9 of Appendix K, which they contend would

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<sup>151</sup> See SBA Office of Advocacy, How to Comply with the Regulatory Flexibility Act, Updated August 2017 (available at <https://cdn.advocacy.sba.gov/wp-content/uploads/2019/06/21110349/How-to-Comply-with-the-RFA.pdf>.) pp. 36.

impose impossible expenses upon small operators that exceed their revenues. For example, the optical gas imaging (OGI) cameras required under this proposal can cost producers more than \$100,000 in addition to the costs for building new reporting systems that come with additional increases in payroll costs as new employees will be needed to process all the documentation requirements.

- Update of emissions profiles for low production, marginal and stripper wells. Commenters (0577 KIOGA, 0824-WDEQ) state that the EPA has never taken any significant data to identify the emissions profile of low production wells. Only the U.S. DOE has initiated a study of emissions from low production wells. That study should be completed in 2021.<sup>152</sup>
- Address various producing areas, For example, Michigan's Antrim basin. (0411-REM)
- The EPA should consider the risk that these businesses will leave the industry and whether there is a risk that wells will be abandoned because of the regulations. (0924-USSBA)

Commenter (1422-U.S. Congress) believes the proposed regulations could put extreme financial burdens on small businesses. For example, they state that optical gas imaging cameras required under this proposal can cost producers more than \$100,000. On top of expensive one-time investments required by the proposed regulation, the additional documentation costs cannot be overlooked. Building new reporting systems is expensive and will come with additional increases in payroll costs as new employees will be needed to process all of the required documentation. The commenter asserts that these added costs are simply not feasible for smaller operations. Smaller producers do not have the same economies of scale as larger producers and cannot spread increases in fixed compliance costs over as many projects. This could result in many of them going out of business as they struggle to maintain profitability.

Several commenters (0793-PBPA, 0924-USSBA, 0411-REM, 0824-WDEQ, 1341-Conventional Groups, 0431-NOI, 0577-KIOGA, 0946-MOGA) in support of their concerns, provide data and analysis related to small businesses, marginal wells, stripper wells and low-production wells for EPA consideration.

Commenter (0793-PBPA) states that databases such as ones developed by Enverus' (formerly known as Drillinginfo), shows that there are approximately 2,960 different operators operating 186,338 Texas oil wells that produce approximately 4,900,000 bpd. Eighty percent of the daily production is generated from the top 1% of the total operators. Furthermore, 49% of the wells are operated by the top 1% of operators. On the other hand, 94% of operators produce only 3% of the total oil production (152,000 bpd) and operate 37% of the wells in Texas. Most of the 94% described above would be considered small businesses, and those entities' average production per well is about 2.2 bpd—dwarfed by average production per well of 56.5 bpd for the largest 1% of operators. The commenter contends that the proposed rule will disproportionately impact these small operators. For example, the additional burden of quarterly leak detection and repair (LDAR) surveys will be significant and, using the EPA's own numbers, will equate to approximately 25% of the operating revenue for those wells.

Using the same example above, the commenter (0793-PBPA) notes that the average production for 94% of Texas operators is 2.2 bpd, which sells for approximately \$55 per barrel. At the same

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<sup>152</sup> "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" (under review), U.S. Department of Energy, National Energy Technology Laboratory: <https://netl.doe.gov/node/9373>

time, the commenter reports that the annual compliance cost associated with replacing existing pneumatic valves and quarterly LDAR at each facility and semiannual well sites is roughly \$5,880, or almost 18% of gross revenues for 94% of Texas operators. The commenter adds that new OGI requirements in Appendix K will cost up to three times the existing costs, pushing compliance costs for 94% of Texas operators to over 50% of existing revenues. According to the commenter, that's all prior to considering other operating costs.

To illustrate the effect of increasing costs 18%, the commenter (0793-PBPA) states that a company operating approximately 1,350 wells averaging 79 bpd would have approximately 15% of all wells become immediately uneconomic if costs increased \$5,880 per year at \$55 per barrel. That means that for this one operator, the production of 550 bpd (0.5% of immediate production) immediately becomes uneconomic. The EPA estimated that, at its peak, the rule would impact approximately 33,400 bpd of domestic production, but the immediate effect in Texas alone is likely to be more than five times that number. Thus, over the life of the rule, the commenter contends that the compliance costs could reduce expected recoverable reserves by about 6%, or for the operator described above, 8.5 million barrels. The commenter suggests that, if compliance costs are anything more than estimated by the EPA, such increase will have a proportional effect on production and be even greater than the above example.

Another commenter (0924-USSBA) states that small businesses also face a greater burden proportionally to comply with reporting and recordkeeping costs. For example, the EPA estimates the annual reporting and recordkeeping burden of NSPS OOOOa compliance to be 87 hours per respondent.<sup>153</sup> Using the above example of the crude petroleum extraction industry, for a firm of five employees, this would mean that no less than 0.84 percent of the business's total hours in a year would be devoted to regulatory compliance for just this component. However, for a business with 500 employees, they would presumably have 1,040,000 labor hours per year (500 employees working 2,080 hours a year) at their disposal, meaning the percent of total hours they would have to use to comply with this regulation would be 0.008 percent. Therefore, smaller businesses would have to spend a greater percentage of their time and labor costs complying than larger businesses.

Another commenter (0411-REM) states that in Michigan's Antrim producing horizon the average well only produces 15 thousand cubic feet (Mcf) per day. The profit margins are minimal to keep these wells economic to produce, yet with over 10,000 of these wells producing they supply vital heat for Michigan homes through long cold winters. Using the EPA's \$3.13/Mcf, the Michigan basin averages a \$0.19/Mcf lower gas price basis than the normal gas index price. An average Antrim well would generate \$1,058.40 a month after paying a 20% royalty to landowners before expenses. To transport this gas to market and treat the gas to make it sellable costs on average \$0.30/Mcf for transportation and \$0.35/Mcf for treating, costing \$234 per month. Costs for operating and compression average \$1.10/Mcf or \$396 per month. Overhead for office and administration averages \$250/well/month. All in, after expenses, an average Michigan Antrim well has a net profit of \$178.40 per month, leaving little room for capital investment.

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<sup>153</sup> 2021 November RIA, pp. 4-54.

Another commenter (0824-WDEQ) notes that the requirements would affect many stripper wells in Wyoming (defined by the Wyoming Oil and Gas Conservation Commission (WOGCC) as wells that produce an average of 15 bbls or less per day) and some very small-scale, independent well site operations that strictly operate on a single owner's private property. According to the WOGCC, Wyoming has approximately 6,524 stripper wells. The commenter adds that the shift to a 3 ton-per-year (tpy) total site-level baseline methane emissions threshold for triggering quarterly OGI monitoring is concerning. The commenter anticipates this new emissions threshold could lead to the quarterly monitoring requirements for many existing stripper wells. According to the commenter, many of these smaller sites simply cannot shoulder the financial burden associated with these requirements and the economic ramifications could be significant. According to the WOGCC, in 2019, there were 6,848 stripper wells in Wyoming that produced a total of 6,959,356 bbls of oil for the year and in 2020, there were 6,524 stripper wells in Wyoming that produced a total of 5,970,758 bbls of oil. Loss of these wells would eliminate jobs and reduce revenue to Wyoming and local communities with no significant environmental benefit.

Another commenter (1341-Conventional Groups) states that conventional wells have lower profitability than unconventional wells and are strongly influenced by oil and natural gas commodity prices and other market forces. For example, in 2020, the commenter reports that Pennsylvania's conventional producers suffered deficits ranging from \$0.50 to \$1.20 per Mcf. They add that, at an annual production of less than 2000 Mcf (expected to occur at about year 17), the average conventional gas well's net revenue becomes inadequate to cover all operating costs. Recovery of capital costs, while more likely with the conventional oil well, is still infeasible in the face of the operating costs. Like the average gas well, the average oil well's net revenue becomes inadequate to cover all operating costs at about year 13, even if the matter of the repayment of the capital costs are ignored.

Commenter (0431-NOI) states that their company operates 170 natural gas wells and 11 oil stripper wells. They consider a well a stripper well if it is less than 15 barrels of oil per day. Since these are low producing wells, they are also minimally profitable especially with occasionally lower per barrel oil sales price. The commenter's small business operational objective is to minimize costs to produce oil from these marginally economical wells to make a profit. The commenter estimates that 75% to 85% of the 770,000 stripper wells in the U.S. would essentially be plugged because compliance would make them uneconomical, and the producers would be under severe stress to comply making it too difficult to endure the cost and added penalties of compliance. In other words, the commenter contends that the remaining reserves of those stripper wells would not allow those wells to be profitable versus the cost it would take to comply. The commenter suggests that, with the current availability of contractors, they expect it would take 3+ year to plug all the stripper wells in our area let alone other parts of the country.

Another commenter (0577-KIOGA) notes that oil and natural gas production systems account for about 1.2% of the US Green House Gases Inventory (GHGI). Low production wells account for about 10-11% of U.S. production. Their emissions would be in the 0.10-0.20% range of the GHGI. There are about 1,000,000 existing oil and natural gas wells. Approximately 150,000 of these wells have been regulated under NSPS OOOO and now NSPS OOOOa. That number grows each year. Of the remainder, 770,000 are low production wells. Nationally, low production wells average about 2.5-2.7 bpd if they are oil wells and 22- 24 Mcf per day if they



are natural gas wells. The commenter states that Kentucky has more than 1,000 oil and gas companies registered to do business with the Kentucky Energy and Environmental Cabinet (KECC) Division of Oil and Gas. This does not include the number of support companies that oil and gas operators contract with to produce energy products. Almost all these operators meet the definition of a Small Business Entity. The proposed regulations will be economically demanding and technically challenging for most of the oil and gas companies throughout Kentucky.

The commenter (0577-KIOGA) adds that the 2021 November proposed emission guidelines (EG) would impose a burden and costs for the small businesses that make up the independent oil and gas industry and for the state of Kansas. The commenter explains that there are over 62,000 oil wells and over 20,000 natural gas wells in Kansas. They note that other comparable states estimated costs to develop and implement the 2021 November proposed rulemaking to be over \$40 million annually. Furthermore, these states estimate the cost on the proposed timing (final compliance within 2 years) is higher (over \$278 million annually). The commenter states that this estimate includes the need for 2,708 additional full time equivalent persons to be hired. They assert that Kansas would incur similar costs.

Commenter (0946-MOGA) provides information related to small businesses in Michigan:

- Approximately 98.8-99% of all oil companies are owned by small businesses and that approximately 92.9-93. 7% of all natural gas companies are owned by small businesses.
- MOGA membership constitutes around 650 members.
- In total, the oil and gas industry in Michigan directly or indirectly employs roughly 47,000 voting residents.

Another commenter (0749-PAW) states that Wyoming is a top-10 producer of oil and natural gas. And that recent studies show this industry supports over 68,000 jobs in Wyoming and contributes \$10 billion in economic activity. According to the commenter, the 2021 November regulatory proposal will have consequential implications across the industry and will have an acute impact on the economics of smaller operations, of which Wyoming is home to many.

Response I-20-27: EPA disagrees with commenters' assertions that it has not adequately considered the impacts of the rule on small producers. As a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule; compliance with the RFA regarding the EG OOOOc will be addressed as part of the process of developing the federal plan. Still, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart.

In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. For example, in response to commenters (e.g., 0824-WDEQ, 1422-U.S. Congress, and 0793-PBPA) concerns about the cost of Appendix K and OGI monitoring in general, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In

addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In addition, contrary to some commenters' assertions (0431-NOI, 0793-PBPA) EPA disagrees that the regulation will lead to the plugging of most (75-80%) marginal wells or significant losses of production. Neither commenter included enough information about the assumptions underlying their assertions for EPA to assess the claims made, but EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. Moreover, to mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s). EPA is unable to assess the viability of the owners and operators of the marginal wells, and as such, EPA is therefore unable to predict which firms will be most adversely affected by regulatory costs.

In response to comments that state that the EPA must perform small business-specific cost evaluation for all sources under the proposed rule using a more granular approach to the cost-effectiveness analysis and that unique aspects of small businesses were not considered in the development of analyses, we disagree. When conducting BSER for affected facilities/designated facilities, one aspect is to evaluate the cost of a control. As part of that evaluation, the EPA considers various associated costs, including capital costs and operating costs (and retrofit costs and challenges), including costs provided by commenters (including small businesses). While our analyses do not reflect every known scenario and equipment configuration, the EPA addresses unique circumstances presented by commenters where it is supported. As an example, see section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the final rule preamble, where a commenter provided information to support an alternative performance-based volumetric flow rate standard for wet seal compressors equipped with a seal oil gas separation system utilized on the ANS.

As discussed in section VIII.B (How does EPA evaluate control costs in this final action?) of the final rule preamble, the final standards will impose some new costs on industry (including small businesses). Many of the standards, however, reflect control mechanisms and measures that many companies and sources around the country are already implementing — again, without deleterious effect on industry as a whole — which shows not only that such controls are “adequately demonstrated” but also underscores their reasonableness from a cost perspective. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in the November 2021 Proposal and the December 2022 Supplemental Proposal, as well as in section XI of this preamble and associated TSDs. See also Volume II, Chapter 4 (Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations), section 4.3.4 (Small Business/Cost Concerns) comments and responses on small business/cost concerns related to fugitive emissions requirements.

With regards to comment that the estimated costs are understated. The EPA updated costs in December 2022 Supplemental Proposal analyses based on specific costs provided by differing commenters on the November 2021 Proposal for several affected facilities/designated facilities, as appropriate. The EPA has maintained costs used in BSER analyses to represent 2019 dollars.

Also, as noted above, the revised IRFA and FRFA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. In addition to providing several compliance alternatives for affected facilities under NSPS OOOOb and designated facilities under EG OOOOc, the EPA has also considered issues such as lingering supply chain issues and increased demand for equipment and services when establishing compliance, and repair and delay of repair provisions included in the final NSPS OOOOb and EG OOOOc rules to account for parts not being available.<sup>154</sup>

Additionally, both NSPS OOOOb and EG OOOOc include provisions that could be pursued for an alternative but equivalent compliance option under NSPS OOOOb or equivalent or less stringent requirements considering remaining useful life and other factors (RULOF) under EG OOOOc under a state plan. 40 CFR 60.5399b (What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?) of NSPS OOOOb provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. See section XIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for state plan requirements and sub-section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

For other comments arguing that EPA's one-size fits all approach does not adequately address the variability across the industry and EPA's responses, see Volume I, Chapter 23 (Miscellaneous Other Comments), section 23.17 (One-Size Fits All Approach) of this RTC document.

In response to the comment suggesting that the monitoring surveys outlined in section 9 of Appendix K would impose impossible expenses on small operators, the EPA, in response to the comments received on the November 2021 Proposal, proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. In the final rule, the EPA is not requiring OGI monitoring in accordance with the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 Proposal. Instead, the EPA is requiring OGI surveys following the procedures specified in the regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21. This change is consistent with the requirements for OGI surveys found in NSPS OOOOa at 40 CFR 60.5397a. For details, please see discussion in

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<sup>154</sup> See sections XI.A.1.e (Delay of repair due to parts unavailability) of the final rule preamble for example.

section IV.A.1.a.ii and IV.A.2.a of the December 2022 Supplemental Proposal<sup>155</sup> related to fugitive emissions from well sites, centralized production facilities, and compressor stations; and discussion in section XVII (Regulatory Flexibility Analysis (RFA)) in the final rule preamble.

In response to comment that refers to the U.S. DOE study of emissions from low production wells, see EPA's responses to similar comments and EPA's review of the study in section XI.A.1.d (Subcategorization of well sites) of the final rule preamble.

Comment: Several commenters (0929-NSWA, 0585-KOGA, 0425-Darrah, 0424-WV DEPDAQ, 0464-MOPC, 0465-JDC, 0424-WV DEPDAQ) express concern that the proposed regulations will facilitate a landslide of premature well plugging in rural communities. Particularly of wells owned by individual homeowners, farmers, or small business entities such as family limited partnerships. Additional impact to these rural community is loss of the well energy source. Many homeowners use natural gas production from their wells to heat their homes. Many farmers utilize farm taps to existing energy assets on, or near, their farm to provide heat to their home and farm buildings / grain drying equipment. The current electric power infrastructure will not support the increase in power demand for some of the homeowners/farmers that are currently supplied by natural gas. The loss of energy and revenue will also have a ripple effect on other support and service sector small businesses, as well as rural towns themselves that rely on the industry to survive. Notably these small operators serve hundreds of customers in small towns and rural areas who heat and cook with natural gas, this potential outcome would negatively impact these citizens; many of whom are low income or on fixed incomes.

Commenter (0424-WV DEPDAQ) is deeply concerned about the subset of existing well sites that are owned by individual homeowners, farmers, or companies with very few employees such as family limited partnerships. The commenter states that the RIA for the 2021 November proposed rulemaking does not address the cost burden to homeowners and farmers who heat their home with a natural gas well that either is on their property or have access to it for allowing right-of-way for a pipeline across their property. The commenter suggests that, because the EPA has not been fully able to evaluate the cost burden on homeowners and farmers who use the natural gas production for the purpose of heating their home [86 Fed. Reg. 63174], those individuals or very small businesses should be exempt from regulation.

Response I-20-28: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis

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<sup>155</sup> 87 FR 74722-74723 and 74739.

suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In addition, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s).

Comment: Several commenters recommend relief for small businesses, marginal wells, stripper wells and low-production wells. Suggestions provided include:

- The threshold for emissions monitoring in tons per year (tpy) needs to be at least doubled because of the cost of compliance is simply too high versus the benefit that would be derived from it.
- Individual homeowners, farmers, and small business with very few employees should be exempt. (0424-WVDAQ, 0577-KIOGA)
- Marginally producing wells (15 barrels of oil equivalent per day (BOEPD)/90 thousand cubic feet per day (MCFPD) or less) must be exempt from EPA rules because the emissions are insignificant, and the rules would be uneconomic. There must be a regulatory "off ramp" for wells such as ours that are low producers. (0464-MOPC, 0465-JDC, 0923-Lambda)
- Recommend that the same exemptions allowed for Alaska be provided for other areas with the same cold weather challenges. (0431-NOI)
- Grandfather in marginal wells to preserve production while focusing on higher producing, more profitable wells for emissions related capital expenditures. (0411-REM)
- Withdraw the regulations for small business. (0193-NFIB)

Commenter (1341-Conventional Groups) states that the EPA's projected cost for the 2021 November proposed new LDAR requirements of \$4,227 per well site in the first year and \$3,200 per well site per year on an ongoing basis would be financially devastating to virtually every member of the Conventional Groups. The commenter adds that:

- The vast majority of Pennsylvania conventional oil and gas wells were drilled more than 15 years ago. The same is generally true for those in New York.
- It is no longer economical to drill new conventional oil or gas wells in Pennsylvania, due to the significant drop in natural gas prices in Pennsylvania caused by unconventional gas well production.
- These economic forces have resulted in no new conventional gas wells being drilled in southwestern Pennsylvania in over five years.

- In all, the drilling of new conventional oil and gas wells has dropped 98% over those last 15 years.

According to the commenter (1341-Conventional Groups), given that most of the conventional oil and gas wells were drilled more than 10 years ago, those wells have already reached the point where annual gross revenue is close to and may be below the EPA's projected first-year compliance cost for the Proposal's LDAR requirements. The commenter states that such projected compliance costs are certainly "exorbitant," "excessive," "unreasonable," and far "greater than the industry could bear to survive. The commenter suggests that EPA should not be proposing LDAR requirements that would place the critically important conventional oil and gas industry in economic peril, simply so any methane and VOC emission from these low-producing and low-emitting well sites can be reduced by a fraction.

Response I-20-29: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In addition, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To mitigate the impact of orphaned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s).

Comment: Commenter (0822-TAEP) states that the proposed requirements will require new hires and expenditures that will hit small business operators especially hard, and the commenter urges the EPA to reconsider measures to protect small businesses from costly regulation that limits their ability to compete, let alone function, under the added administrative burdens. Employment in the industry has been severely impacted by COVID-19 and a contraction of the industry since the EPA did their last analysis on manpower cost and time requirements. These factors, combined with the increasing burden of inflation will likely result in higher servicing and equipment costs for operators, further exacerbating the burden of compliance. The commenter suggests that the DOE's analysis of marginal wells and their potential emissions may

help to shed additional light on the potential risk profile of those assets which are universal across the industry, held by small and large operator alike. In both cases, if the costs to operate exceed the facility's production value, those operators will shut-in that asset, losing domestic production.

Commenters (0946-MOGO, 0824-WDEQ, 1341-Conventional Groups) express concern with EPA's apparent lack of knowledge, characterization and generalization of the oil and gas production environment, which they believe will result in a discriminatory "one-size-fits-all" approach which will place a tremendous financial burden on small business operators based on incorrect assumptions and data. Commenter (0824-WDEQ) suggests that EPA fully integrate all existing control program approaches and the benefits and costs of technology standards before adding more regulations.

Commenter (0763-TCEQ) is concerned that EPA's analysis of the costs associated with the proposal are based on the overall capital expenditures and income of the industry as a whole, whereas the companies in Texas involved in the oil and gas industry vary greatly in size and resources. The commenter is concerned that basing the reasonableness of regulations on industry-wide data misses the greater impact to small businesses, especially those operating low-production wells. The commenter states that the costs of complying with the proposed requirements at the numerous small mom and pop operators will be extremely high compared to the income from their operations. By way of example, the commenter states that in Texas alone, over 4,100 operators own and operate 10 or less oil leases and gas wells.

Response I-20-30: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In addition, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from

the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s).

Comment: Commenter (0946-MOGA) notes that the EPA did not consider or incorporate comments and concerns regarding the technical and financial infeasibility resulting from limited and condensed interactions with the small business segment of the oil and gas production industry before proposing new regulations. The commenter and others participated as a small entity representative (SER) on the Small Business Advocacy Review ("SBAR") Panel Process required under the Regulatory Flexibility Act ("RFA"), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA). The commenter is reiterating several of our final comments submitted to the EPA on August 12, 2021, to highlight their concern with the EPA's lack of consideration and incorporation of SER's concerns and comments prior to the publication of the current proposed regulations.

Response I-20-31: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

### ***20.2.8 Employment Impacts***

Comment: Several commenters provide input regarding how they believe the 2021 November proposed rule will affect industry employment overall and in their states. Examples of some of the comments provided are included in the following paragraphs.

Commenter (0822-TAEP) notes that the EPA's proposal will necessitate additional workforce to facilitate equipment changeovers, additional monitoring and reporting duties, and a growing administrative compliance obligation. The commenter asserts that the need for new hires will hit small business operators especially hard.

Commenter (1302-WOC) believes that as the standards around methane emissions are developed, the oil and natural gas sector is poised to grow and create new jobs, helping Wyoming modernize its oil and gas infrastructure and stay competitive as consumer energy preferences change to favor low-carbon fuel sources. The commenter states that the creation of new jobs in this sector could help employ current and former workers in the oil and gas industry. They add that the EPA's new methane rules will continue to encourage the growth of similar such monitoring technologies and businesses, creating new jobs, more cost-effective ways to



implement and scale leak detection and repair, and reducing the impact of energy development on climate change and air quality.

Commenter (1423-USCongress) states that reducing methane emissions can create good, high-quality jobs. The methane mitigation service sector in the U.S. has nearly doubled in size since 2017 and would have further opportunity to grow.<sup>156</sup>

Conversely, commenter (0728-OK DEQ) states that one issue of concern they have is the lack of any detailed projections of likely reductions in oil and gas employment. They explain that this is particularly concerning in Oklahoma due to the number of marginal wells that remain in operation and whose financial viability may be precarious. The commenter adds that the jobs in the oil and gas sector are particularly well-paying when compared to alternatives, especially in rural areas and, because job losses are likely to be localized, the effects are magnified in those communities. Further, they state that it is their contention that the economic impacts of the proposed rules will likely be significantly harmful to rural communities dependent on this industry. It is with this concern in mind that the commenter recommends that the EPA consider economic impacts of the proposed rulemaking with the same level of granularity and diligence that was used in evaluating benefits of the rule for environmental justice comments. The importance of oil and gas jobs is further warranted by the information in Table 4-8 of the 2021 November proposed rule RIA which shows that the average income for oil and natural gas workers is \$110,000 while the average income for other workers in “oil and gas communities” is \$40,000. Thus, for every oil and gas job lost, even if there is a new non-oil and gas job created in the same community, there will be a net loss of \$71,000 with additional spillover effects in the community.

Commenter (0597-IOGA) indicates that in addition to losing energy sources and royalty income, jobs will also be lost as the needed staff decreases. As a substantial number of marginal wells are plugged, our members will be forced to reduce staff because they cannot afford to continue to pay them with a smaller revenue stream. The commenter contends that this loss of good paying jobs will have a direct impact on our communities. We believe that the EPA’s proposed regulations will continue to support the decline in oil production throughout the state of Indiana. According to the commenter, the additional costs from NSPS OOOOa discouraged many operators from performing work on their assets due to the additional compliance costs. The commenter reports that their members provide a critical energy source and reliable income for communities.

Commenter (1300-PLS) states that, as noted above (section 20.2.7), they believe that the proposed rules will result in huge financial burdens for Small Independent Oil & Gas Operators making stripper wells uneconomic to produce. According to the commenter, if these natural gas and oil wells cease to produce, there will be numerous good-paying jobs lost in our rural Montana communities, with subsequent loss in local tax dollars for community infrastructure. The commenter explains that these small highline communities cannot be compared to other communities, due to the rural nature and sparse population, being under 1,100 people, who

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<sup>156</sup> Lowe, Marcy, et al.. “Find, Measure, Mix: Jobs in the U.S. Methane Emissions Mitigation Industry.” Environmental Defense Fund Report, Prepared by Datu Research, June 2021.  
<https://www.edf.org/sites/default/files/content/FindMeasureFixReport2021.pdf>

depend heavily on these natural resource jobs. The commenter recommends that stripper natural gas and oil wells be exempt from these rules and regulations.

Commenters (0431-NOI, 1341-Conventional Groups) note that they cannot find contractors or personnel now that could both modify the equipment for compliance to meet 2021 November proposed requirements and to handle the daily or quarterly compliance issues. As discussed in section 20.2.7 of this Chapter, commenter (0924-USSBA) notes that small businesses frequently lack the benefits packages larger businesses have (quality of healthcare, and other benefits) leaving smaller businesses at a disadvantage when hiring compliance staff.

Response I-20-32: EPA acknowledges the challenge in assessing the employment impacts of the regulation. To the extent that regulatory costs lead to reduced production, sector employment could be reduced, though this is not guaranteed as firms could simultaneously reallocate expenditures on productive inputs away from capital and towards labor because of the regulation. In addition, as noted by some commenters, the regulation may also increase employment by increasing the demand for compliance-related labor. The net effect is ambiguous without sufficient data, which hasn't been provided by commenters.

Specific to small business employment, in the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. According to commenters, the steps taken to alleviate burden on small businesses should mitigate impacts on employment at those firms.

### ***20.2.9 Intergovernmental Panel Climate Change (IPCC) Climate Report – Social Cost Metrics***

Comment: Commenter (0804- CCES et al) states that critics allege that the chosen Equilibrium Climate Sensitivity (ECS) distribution—that is, the amount of warming that is expected to result from a doubling of the atmospheric CO<sub>2</sub> concentration—is outdated and fails to account for recent evidence showing that sensitivity to be lower than previously believed. According to the commenter, these arguments rely on cherry-picked data and ignore the scientific consensus.

In 2016, the commenter (0804- CCES et al) states that the National Academies of Sciences (NAS) dedicated an entire report to whether the Working Group should update the social cost metrics to reflect more recent science on the ECS. The NAS decided that such an update was unnecessary, “recommend[ing] against a near-term change in the distributional form of the ECS” and explaining that any reasonable revisions on this front would “have a minimal impact on estimates of the [social cost of greenhouse gases].”<sup>157</sup>

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<sup>157</sup> Nat'l Acad. Scis., Eng'g & Med., Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on a Near-Term Update 34, 46 (2016), available at <https://perma.cc/TJM6-XE65> [hereinafter “NAS 2016 Report”].

On top of the NAS' rejection of this argument, the commenter (0804- CCES et al) asserts that there is little support for the claim that the Working Group overstated the pace of climate change. The most recent estimate from the IPCC—which reflects consensus estimates from the worldwide scientific community—projects an ECS range from 2.5°C to 4°C, with 3°C as a “best estimate.”<sup>158</sup> According to the commenter, this is consistent with the range applied by the Working Group—based off of Roe & Baker—which uses 3°C as its median and 3.5 °C as its mean ECS value.<sup>159</sup> In evaluating the ECS, the Working Group assessed estimates from a wide range of experts and selected consensus values. In fact, as the Working Group acknowledged, some ECS estimate ranges go as high as 10° C, making its selected ECS distribution substantially lower than these high-end estimates and a reasonable middle range.<sup>160</sup>

In previous dockets, the commenter (0804- CCES et al) states that opponents of the Working Group's estimates have cited Lewis & Curry (2015)—which estimates a median ECS of 1.64 °C with an uncertainty range (5–95%) of 1.05–4.05 °C—to suggest that the Working Group applied an inappropriately high ECS range.<sup>161</sup> But in light of the consensus estimates discussed above, that paper is a severe outlier. Since its publication, in fact, Lewis & Curry (2015) has been criticized by other climate scientists for methodological deficiencies that cause it to underestimate the ECS.<sup>162</sup> And as noted above, the National Academies did not think that Lewis & Curry (2015) merited an update to the Working Group's valuations to revise the ECS estimates.<sup>163</sup>

The commenter (0804- CCES et al) adds that critics further argue that the ECS distribution applied by the Working Group inappropriately skews rightward, meaning that its mean ECS value exceeds the median value of 3° C that the IPCC has indicated. But that decision is a feature, not a bug. As the National Academies explained, the IPCC has found that there is a “positively skewed distributional form for [the ECS] parameter” similar to the ECS distribution applied by the Working Group.<sup>164</sup> In other words, the commenter states that the mean ECS value should be higher than the median ECS value, and the Working Group applied an appropriate distribution. Criticisms to the contrary are meritless.

Commenter (0804-CCES et al) notes that critics further argue that the Working Group's valuations are an overestimate because they apply outdated emission scenarios that exaggerate the baseline level of atmospheric greenhouse gas levels. The commenter explains that using a higher baseline level of emissions raises the social cost estimates because the harm from an additional unit of emissions increases with the baseline atmospheric emissions level. However, the commenter states that the Working Group used a reasonable emissions baseline that reflects different possible mitigation scenarios.

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<sup>158</sup> IPCC, AR6 Synthesis Report SPM-14 (2021).

<sup>159</sup> 2010 TSD, *supra* note 91, at 13 tbl.1.

<sup>160</sup> *Id.* at 14 fig.2.

<sup>161</sup> Nicholas Lewis & Judith A. Curry, The Implications for Climate Sensitivity of AR5 Forcing and Heat Uptake Estimates, 45 *Climate Dynamics* 1009 (2015).

<sup>162</sup> See, e.g., Kate Marvel et al., Internal Variability and Disequilibrium Confound Estimates of Climate Sensitivity from Observations, 45 *GEOPHYS. RES. LETT.* 1595 (2018); Timothy Andrews et al., Accounting for Temperature Patterns Increases Historical Estimates of Climate Sensitivity, 45 *GEOPHYS. RES. LETT.* 8490 (2018).

<sup>163</sup> NAS 2016 Report, *supra* note 207.

<sup>164</sup> *Id.* at 25.

According to the commenter (0804-CCES et al), while the Working Group assumed a baseline emissions range of 13–118 gigatons of carbon dioxide emitted per year by 2100,<sup>165</sup> recent projections from the Climate Action Tracker indicate that baseline emissions will reach between 14–175 gigatons of carbon dioxide by 2100 under a range of scenarios reflecting different levels of mitigation.<sup>166</sup> Thus, the commenter contends that the baselines used by the Working Group potentially understate baseline emissions rather than overvalue them as opponents argue. In fact, several of the Working Group’s supposedly “business-as-usual” scenarios are actually more consistent with baseline estimates reflecting policy projections.<sup>167</sup> Accordingly, they add that the criticism that the Working Group overestimated future greenhouse gas concentrations in the atmosphere falls flat.

Moreover, the commenter (0804-CCES et al) states that this choice does not particularly affect the social cost valuations. In comparison to the Working Group’s central social cost of carbon estimate in 2020 of \$51 per ton, the commenter reports that the average social cost of carbon under the Working Group’s supposed business-as-usual emissions scenarios is \$53 per ton and \$41 per ton under the emissions scenario that is consistent with sustained and widespread mitigatory action.<sup>168</sup> While relying less on the Working Group’s supposed business-as-usual scenarios would therefore modestly decrease the interim social cost valuations in a vacuum, more holistic updates to the metrics as recommended by the NAS would very likely increase the social cost valuations overall due to the omitted damages discussed above and recent evidence regarding intergenerational discount rates.<sup>169</sup> At best, therefore, the comment contends that this argument makes a mountain out of a molehill.

Commenter (0804-CCES et al) states that critics further claim that the IAMs—the damage functions for translating climate impacts into economic losses—are flawed and arbitrary. However, the damage functions are based on reasonable assumptions made by a range of experts.<sup>170</sup> They have also withstood scientific scrutiny, and while opponents of climate reform frequently highlight criticism of the damage functions by a notable economist, they take this criticism out of context.

The commenter (0804-CCES et al) explains that the Working Group selected three models of climate damages that were the most widely used and cited models in the economics literature linking physical climate impacts to economic damages<sup>171</sup>: the DICE, FUND, and PAGE models.<sup>172</sup> These models were developed by outside experts, published in peer-reviewed

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<sup>165</sup> 2010 TSD, supra note 91, at 16 tbl.2.

<sup>166</sup> Climate Action Tracker, Global Emissions Time Series (Dec. 1, 2020), available at <https://perma.cc/B4X2-RAWA>.

<sup>167</sup> Compare id. (projecting 35–48 gigatons of emissions in 2100 under “current policy projections” scenarios and 83–175 gigatons under business-as-usual scenario) with 2010 TSD, supra note 91, at 16 tbl.2 (incorporating supposedly business-as-usual scenarios of 42.7 and 60.1 gigatons in 2100).

<sup>168</sup> See Peter Howard et al., Option Value and the Social Cost of Carbon: What Are We Waiting For? (Inst. for Pol’y Integrity Working Paper No. 2020/1) at 16 tbl.1 (2020), available at [https://policyintegrity.org/files/publications/Working\\_paper\\_06.22.20.pdf](https://policyintegrity.org/files/publications/Working_paper_06.22.20.pdf).

<sup>169</sup> See 2021 TSD, supra note 5, at 4 (Working Group acknowledging that its current social cost valuations “likely underestimate societal damages from [greenhouse gas] emissions”).

<sup>170</sup> Response to Comments, supra note 106, at 8.

<sup>171</sup> Id.

<sup>172</sup> 2010 TSD, supra note 91, at 5.

economic literature,<sup>173</sup> and were the product of extensive scholarship and expertise. One of the models, DICE, was developed by William Nordhaus, an economics professor and former provost of Yale university who won a Nobel Memorial Prize in Economic Sciences for developing the model. And PAGE's developer, Chris Hope, was a lead author and review editor for the Third and Fourth Assessment Reports of the IPCC, which shared the Nobel Peace Prize in 2007 with former U.S. Vice President Al Gore.<sup>174</sup>

The commenter (0804-CCES et al) states that the three models reflect a wide diversity of methodological assumptions about a range of key parameters and inputs.<sup>175</sup> This reflects, in part, different judgments about the experts who developed the models. For instance, Richard Tol, who developed the FUND model, has stated that “[t]he impact of climate change is relatively small,” and dismissed much of the research behind climate change as “scaremongering” rather than “sound science.”<sup>176</sup> Unsurprisingly, his model produces the lowest damage estimates of the three models incorporated by the Working Group.<sup>177</sup> William Nordhaus, who developed the DICE model, is widely credited with popularizing the goal that global temperatures increase no more than 2° Celsius (or 3.6° Fahrenheit) below pre-industrial levels<sup>178</sup>—a goal now considered conservative by the global community.<sup>179</sup> His model produces higher damage estimates that are close to the Working Group's average damage valuations.<sup>180</sup>

The commenter (0804-CCES et al) adds that opponents of climate mitigation policy frequently point to criticisms from Robert S. Pindyck, a noted climate economist who has been critical of the Working Group's choice of damage functions. But as Professor Pindyck has himself stated, his “writings continue to be taken out of context by some to unfairly attack the Interagency Working Group's methodology and its interim estimates.”<sup>181</sup> While Professor Pindyck has questioned the shape of the models' damage functions,<sup>182</sup> he has acknowledged that the damage functions reflect “common beliefs” about the effects of two or three degrees of warming.

The commenter (0804-CCES et al) further adds that Pindyck states that uncertainty about the social cost estimates, including the damage functions, “does not imply that [their] value should be set to zero until the uncertainty is resolved.”<sup>183</sup> In fact, he actually advocates for an even

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<sup>173</sup> Response to Comments, supra note supra note 106, at 4.

<sup>174</sup> See Chris Hope faculty bio page, University of Cambridge Judge Business School, <https://www.jbs.cam.ac.uk/faculty-research/research-teaching-staff/chris-hope/> (last visited Sept. 24, 2021).

<sup>175</sup> See 2010 TSD, supra note 91, at 6.

<sup>176</sup> Richard S.J. Tol, Why Worry About Climate Change?, ESRI Research Bulletin 2009/1/1, at 3, 5 (2009).

<sup>177</sup> See 2010 TSD, supra note 91, at 50 tbl.A5.

<sup>178</sup> The 2° C Limit on Global Warming, *The Economist* (Dec. 6, 2015), <https://www.economist.com/theeconomist-explains/2015/12/06/the-2degc-limit-on-global-warming>.

<sup>179</sup> Paris Agreement to the United Nations Framework Convention on Climate Change, Art. 2(1)(a), Dec. 12, 2015, T.I.A.S. No. 16-1104.

<sup>180</sup> Compare 2010 TSD, supra note 91, at 50 tbl.A5 with id. at 1.

<sup>181</sup> Robert S. Pindyck, Comments on “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990” at 1 (June 15, 2021), available at <https://www.regulations.gov/comment/OMB-2021-0006-0012>.

<sup>182</sup> Robert S. Pindyck, Climate Change Policy: What do the Models Tell Us? (Nat'l Bureau of Econ. Research, Working Paper No. 19244) 16 (2013), available at <https://perma.cc/G25M-MA7W>.

<sup>183</sup> Robert S. Pindyck, Comments to Ms. Catherine Cook, Bureau of Land Management, on Proposed Rule and Regulatory Impact Analysis on Delay and Suspension of Certain Requirements for Waste Prevention and Resource Conservation 3 (Nov. 6, 2017), available at <https://perma.cc/8MY5-58P5>; see also Pindyck, supra note 232, at 16.

higher social cost value than that produced by the Working Group,<sup>184</sup> and has emphatically declared that “the federal government should continue to use the [Working Group’s] interim estimates . . . as lower bound estimates.”<sup>185</sup> In other words, the best critic of the Working Group’s methodology that opponents could find supports continued use of the Working Group’s estimates and considers them to be conservative underestimates of the true cost to society of greenhouse gas emissions.

Response I-20-33: As mentioned in previous responses, EPA presented a set of updated social cost of greenhouse gas (SC-GHG) estimates in sensitivity analysis in the 2022 Supplemental RIA that address recommendations of the National Academies of Sciences, Engineering, and Medicine (2017), and invited public comment on the sensitivity analysis and on the technical report, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, explaining the methodological updates that was included as Supplementary Material to the RIA. The EPA is using the updated SC-GHG estimates in the Final RIA and is responding to the public comments received regarding these estimates in the Appendix of this RTC. These estimates have taken on the latest and most up to date science, including updates to the climate model, the socioeconomic, and the damage estimation components. Please refer to the RTC Appendix for detailed responses on these topics. Comment: Commenter (0746-Methane Action) suggests that in the final rule or the next proposal, include the most recent, more demanding, metrics for evaluating the effects of methane and alternatives for removing CH<sub>4</sub>, CO<sub>2</sub>, and related pollutants.

Commenter (0746-Methane Action) asks EPA to respond in the final rulemaking to the suggestions included in these comments, including comments based on a January 26th paper from Stanford University scientists Abernethy and Jackson. The commenter also asks EPA to respond to their suggestion that EPA use the same method for estimating the removal rate that would be necessary to restore or come closer to restoring healthier and safer temperature levels and reducing associated weather and ecological damage from that which we are experiencing at 1.1 degrees C already.

“Global temperature goals should determine the time horizons for greenhouse gas emission metrics”<sup>1</sup> Emission metrics, a crucial tool in setting effective exchange rates between greenhouse gases, currently require an arbitrary choice of time horizon. Here, the commenter (0746-Methane Action) proposes a novel framework that calculates the time horizon that aligns with scenarios achieving a specific temperature goal.

According to the commenter (0746-Methane Action), it must be understood that the reference to “the Biden Administration’s explicit goal” being to keep warming below 1.5 degrees Celsius was in reference to the UNFCCC/Paris Agreement’s COP26 context where changing that goal was not on the formal agenda. The commenter states that they do not intend to suggest here that the EPA limit its regulations, in this case or others, to measures designed to barely or just meet that goal. In fact, U.S. law requires the EPA to use the “BSER” or best available control technologies or to remove as much as possible of hazardous pollutants, depending on which section of the U.S. Code is used and which methods are shown to work. The law is not a license to pollute at

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<sup>184</sup> Pindyck, supra note 231, at 1.

<sup>185</sup> Id.

any level, if pollution is unnecessary or avoidable and we are rapidly learning how to make do with much less methane and the pollutants caused by its production and use and how to remove those that have been emitted.

Response I-20-34: The EPA acknowledges commenter's thoughts regarding the appropriate metric to use for valuing methane. However, the EPA disagrees with the conclusions of the paper by Abernathy and Jackson that metrics should be designed to be optimized for the time horizon at which the temperature threshold to be avoided (e.g., 1.5 degrees C) is expected to be met. There are two flaws in the reasoning from Abernathy and Jackson.<sup>186</sup> First, time does not stop after the time horizon year: the authors recognize this ("it implicitly ignores temperature impacts that occur after the peak"). The second is that the metric design assumes the success of the policy to achieve the peak temperature. The combined problem of these two flaws is that basing policy on the higher value of methane relative to carbon dioxide resulting from this approach could lead to more long-term committed warming. In contrast, the EPA uses the SC-GHG to place a monetary value on methane reductions, which is an estimate of the net damages to society caused by the emissions of a given gas and is an appropriate metric to use for cost benefit analysis. The EPA also uses the 100-year GWP as the internationally recognized standard for reporting emission inventories: the use of an established metric makes it straightforward to compare emissions inventories from different sources. Moreover, several papers have found that the use of 100 years for the GWP time horizon is fairly consistent with a discount rate of 3% (Sarofim and Giordano, 2018, and Mallapragada and Mignone, 2020)<sup>187</sup>, and the use of a shorter time horizon would imply a higher discount rate which is contrary to most studies regarding temporal valuation and Circular A-4 (2023).<sup>188</sup>

Comment: Commenter (0461-High Tide et al) states that their mission is to have a significant, measurable impact on climate change mitigation. The commenter intends for their funding to be catalytic and support scalable solutions to the difficult issue of methane leakage. The commenter partners with a wide variety of nonprofits, foundations, climate philanthropists, companies, universities, and governments to advance the goal of reducing greenhouse gases.

Commenter (0461-High Tide et al) led the effort to raise \$125 million in funding for Carbon Mapper, a non-profit that aims to operate a constellation of satellites to identify methane super-emitters. The commenter also spearheaded the effort to raise \$225 million to establish Methane Hub. This non-profit is working to accelerate the mitigation of methane emissions in the oil and gas, landfill, and agricultural sectors.

The commenter (0461-High Tide et al) is not alone in investing in advanced technology designed to reduce methane emissions from the oil and gas industry. The commenter points to the Climate

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<sup>186</sup> S. Abernathy, R. B. Jackson, Global temperature goals should determine the time horizons for greenhouse gas emission metrics. *Environ. Res. Lett.* 17, 024019 (2022).

<sup>187</sup> Sarofim MC and Giordano MR 2018 A quantitative approach to evaluating the GWP timescale through implicit discount rates *Earth Syst. Dyn.* 9 1013–24 and Mallapragada DS and Mignone BK 2020 A theoretical basis for the equivalence between physical and economic climate metrics and implications for the choice of Global Warming Potential time horizon, *Climatic Change* 158 (2) 107-124.

<sup>188</sup> <https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf>.

Investments arm of the Oil & Gas Climate Initiative, which has pledged to invest \$1 billion in technologies and projects that accelerate decarbonization in oil and gas, industry, and commercial transport.<sup>189</sup> A substantial fraction of this fund has been directed to methane emission reduction.<sup>190</sup>

The commenter (0461-High Tide et al) believes these investments would be inappropriate and unwise if existing, advanced means of methane emission detection and remediation were efficient and effective. Unfortunately, they are not. As evidence, the commenter cites the United States report to the secretariat of the United Nations Framework Convention on Climate Change (UNFCCC), *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2019*<sup>191</sup>, together with its natural gas and petroleum systems Methodology Annexes.<sup>192</sup> Methane emissions from regulated activities in the natural gas and petroleum sectors, normalized to those emissions in 2013, are shown in the figure below. Although comprehensive methane reduction rules were imposed by 40 CFR 60 Subpart OOOO in 2012 (vertical dashed line) and enhanced by 40 CFR 60 Subpart OOOOa in 2016, emission trends have been on a steady but very slow decline since 1990. The commenter finds the compound annual growth rate unimpressive at -0.3%. The commenter contrasts this to the Obama administration's pledge in 2016 to reduce methane emissions at a compound annual growth rate of roughly -6%.<sup>193</sup>

Response I-20-35: The EPA acknowledges the comment.

Comment: Commenter (0414-Waterspirit) urges EPA to stop reporting methane per the 100-year-old emissions CO<sub>2</sub>e; take into account the full life cycle of emissions throughout fossil fuel supply chains.

- Changing this standard will better legitimize the process which moves toward sound policy based upon credibly collected data.
- The current EPA rules encourage all states and agencies to present methane emissions using the older IPCC assessment for the potency of methane at 100 years. Even in this proposed rule, EPA presents Table 7 total Methane emissions using the obsolete 100-year carbon equivalency for quantifying the amount of methane that occurred in 2019, 2010, 1990.
- The original EPA numbers provided are substantially lower given the absent methane emissions not accounted for. Methane emissions have been ever increasing; present-day load is surpassing all current projections of greenhouse gas emissions. No federal agency has taken on assessing the full scope of methane emissions. Reporting of emissions from

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<sup>189</sup> <https://www.ogci.com / climate-investments/>.

<sup>190</sup> <https://www.ogci.com/ climate-investments/ investment-portfolio/>.

<sup>191</sup> <https://www.epa.gov/ghgemissions/ inventory-us-greenhouse-gas-emissions-and-sinks>.

<sup>192</sup> <https://www.epa.gov/ghgemissions/ natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg>.

<sup>193</sup> Leaders' Statement on a North American Climate, Clean Energy, and Environment Partnership, 29 June 2016 <https://obamawhitehouse.archives.gov/the-press-office/ 2016/ 06/ 29/ leaders-statement-north-american-climateclean- energy-and-environment>.



energy companies should be independently reviewed and monitored to reflect present day load and real time data.

Response I-20-36: The commenter requests that EPA stop reporting using the “obsolete” carbon equivalency metric and to take into account the full lifecycle of emissions. With regard to the carbon equivalency metric, the EPA uses the 100-year GWPs from the AR5 IPCC assessment, published in 2013. This complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). The AR5 GWP for methane of 28 is very similar to the IPCC AR6 value for methane of 27.2. Regarding lifecycle accounting and data collection, the EPA works to use the best available, practical methods to account for emissions across the economy. Please consult EPA’s Inventory of U.S. Greenhouse Gas Emissions and Sinks<sup>194</sup> for more data regarding EPA’s processes and the most recent estimates of national emissions.

## **20.3 Other Emissions and Regulatory Impacts Comments**

### ***20.3.1 General Support/Opposition for Proposal to Reduce Emissions***

#### Support

Comment: Several commenters provide general support or opposition to EPA’s 2021 November proposal to reduce methane and VOC emissions from oil and gas operations. Examples of some of those comments are provided in the following paragraphs.

Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0781-National Tribal Air Association (NTAA), 0833-UMUT EPD) believe that EPA’s proposed controls are cost effective and encourage EPA to consider and compare the costs of the controls to the full range of negative costs experienced from the oil and natural gas industry’s high methane, volatile organic compound (VOC), and hazardous air pollutants (HAP) emissions.

Commenter (0458-MDE) supports the proposed rule as it will clearly have a positive impact on mitigating climate change and improving air quality, noting that Environmental Protection Agency (EPA) estimates that 41 million tons of methane emissions will be reduced from the industry between 2023 and 2035 (which is the equivalent of 920 million metric tons of carbon dioxide), and the proposed rule would reduce an estimated 12 million tons of volatile organic compounds (VOC) and 480,000 tons of air toxic pollutants from 2023 to 2035.

Commenter (1294-OCCA) states that the proposed rule changes are a step in the right direction but asserts that it is critical for EPA to adopt rules and regulations that reach across state borders to have a national impact. The commenter believes that the authority to develop these critical regulations must not be delegated to states because some state regulations would be stringent and protective of health while states that are dominated by the fossil fuel industry would be almost certain to have weak or no standards.

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<sup>194</sup> <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>.

Commenter (0912-Shell) states that they support the EPA's efforts to establish rigorous performance standards for reducing methane emissions from new and existing facilities within all segments of the oil and gas sector. The commenter believes that these methane control requirements generally reflect best available control measures.

Commenter (0402-Cancer Free) primary proposed NSPS OOOOb and EG OOOOc rules are a significant first step in reducing GHG and toxic emissions from oil and gas operations. However, they assert that much more stringent emission limits are needed to truly reduce the environmental and human health burden of fossil fuel extraction and production. To date, the commenter notes that most of the research on the human health effects of oil and gas wells is based on proximity to operations—much more refined research is needed, including exposure measurement and biomonitoring, to truly comprehend the range and magnitude of oil and gas operation's effects on human health. In the meantime, the commenter states that more protective emission limits are needed to protect human health, especially given the gap of comprehensive knowledge.

Commenter (0842-NYU School of Law) contends that the 2021 November proposed rule is necessary to correct a market failure which is leading oil and gas producers to capture less pollution that is socially optimal. The commenter states that because methane (a primary component of natural gas) is a valuable commodity, private operators have some incentive to avoid methane leaks, as some methane can be profitably captured and resold. However, the commenter argues, the upfront cost of buying and installing leak detection, repair, and prevention equipment may deter some companies from addressing leaks at their wells. The commenter reasons that absent regulation, oil and gas producers will only capture as much methane and VOC emissions as they can profitably do, from a private welfare-maximizing perspective. But, the commenter cautions, GHG and VOC emissions also impose significant costs on society—such as negative climate, health, and welfare impacts—that are not reflected in the market price of methane. In the absence of regulation, the commenter states, these costs will be borne not by the polluting firm, but by society as a whole and voluntary programs are insufficient to reach optimal levels of methane reduction. The commenter concludes that because methane and VOCs are externalities that impose costs on society—which can be estimated using tools like SC-CH<sub>4</sub>—regulation is required to capture all the methane and VOC emissions that are cost-benefit justified from a social welfare-maximizing perspective.

Commenter (0456-WI DNR) states that the proposed rule addresses needed reductions in methane and VOC emissions from the oil and gas sector that will benefit air quality.

Commenter (0456-WI DNR) states that the reduction of methane emissions from this proposed rule will play a critical role in meeting national GHG emission reduction targets and addressing climate change. EPA notes that methane is a potent GHG with a global warming potential 30 times that of CO<sub>2</sub> and is responsible for approximately one third of current warming due to human activity. EPA also notes that the oil and gas sector is the largest industrial contributor of methane nationwide. This proposal will also reduce VOC emissions that contribute to ozone formation in Wisconsin. While the commenter does not anticipate the proposed rule will significantly decrease VOC emissions from sources in Wisconsin (their state), several states that significantly contribute to ozone nonattainment or maintenance along the Lake Michigan shoreline have large oil and natural gas sectors. Upwind VOC emissions reductions from this

proposed rule may be significant and may improve Wisconsin's ability to attain and maintain ozone standards.

Commenter (0943-SSMTCI) states that they are supportive of the EPA's proposed improvements over the 2012 and 2016 standards and the acknowledgement of technological advancements in the oil and natural gas industry sector over the past few years and appreciates the EPA's explicit recognition that climate change and the oil and natural gas operations disproportionately impact near source low wealth, minority communities, and particularly Tribal communities. The commenter believes that the EPA's proposed controls are cost effective. And encourages the EPA to consider and compare the costs of the controls to the full range of negative costs experienced from the oil and natural gas industry's high methane, VOC, and HAP emissions.

Commenter (0842- NYU School of Law) states that the proposed rule is laudable for significantly reducing methane emission in a legally sound and cost beneficial manner. The Proposed Rule builds on earlier standards for control of methane and VOCs for new sources and is well grounded in the EPA's authority under the Clean Air Act. By regulating existing sources, the EPA wisely avoids the problem of grandfathering. And the Proposed Rule is necessary to correct market failures that are currently producing unaddressed externalities to the public. In addition, the EPA has appropriately monetized the benefits of reducing methane emissions through its use of the social cost of methane.

### Opposition

Conversely, commenters (0750-Flogx, 0439-Paxton, 0577-KIOGA) state that the EPA has applied a one-size-fits-all approach to the regulation of an incredibly diverse industry which they say is already one of the most highly regulated industries in the nation.

Commenter (0439-Paxton) states that as a small-independent producer in Michigan, the margins on which they already operate can vary widely and implementing regulations which are "one-size fits all" will have a devastating effect on their ability to continue to operate at all. The regulations will not only affect the private landowners who are paid royalties for their minerals but the economy of State of Michigan itself. The commenter continues that oil and natural gas will remain the foundation of our gigantic energy complex even as we transition to new alternatives. However, as a business, it is impossible to continue to plan to meet increased energy demands if the very nature of the science and engineering we are implementing is so broadly misunderstood by regulators.

Another commenter (0577-KIOGA) notes that the EPA states that much of the methane and VOCs that are captured because of this regulation will be sold into the natural gas market. The EPA is expecting owners and operators to use the gas sales to offset compliance costs. However, most of the gas that is not being sold today costs too much for owners and operators to collect, process, transport, and sell into the natural gas market. Many wells drilled and produced in Kansas have associated gas that needs to be purified to make it pipeline quality, which is a significant investment for a small volume of produced gas and if projects to collect, process, and sell gas were economically attractive, companies would have already made the investment. The commenter stated that they performed Monte Carlo simulations around expected Kansas gas

production, gas quality, compliance cost, operating cost, and product pricing. The outcome of their simulations shows that none of the scenarios are profitable (positive Net Present Value (NPV)) and any management team would reject the investment opportunity. Every well drilled will only have additional compliance costs added and no economic benefit will be realized.

Commenter (0923-Lambda) notes that they and other producers have been complying with emission reduction rule changes since 2012 with NSPS OOOO, in 2016 with NSPS OOOOa, in 2020 (a policy change), in 2021 (a technical change) and now again with the current rule change. With so many changes to regulations in a short period of time, the commenter asks how EPA can know whether the previous regulations have been effective? Section 111 of the CAA requires a review every eight years, and although waiting the full eight years may not be prudent, many changes within that time frame cost producers an exorbitant amount of time, capital investment on equipment, increased 3rd-party outsourcing costs, and new burdens on compliance staff. The commenter's position is that NSPS OOOOa is already effective at regulating new sources and achieves the goals of reducing emissions on the largest known source of emissions (new sources with high production), in addition to providing regulatory coverage of modified existing facilities with new emission sources.

Commenter (0193-NFIB) states that America depends upon affordable oil products and natural gas for the energy that keeps the American economy going. The commenter states that American businesses of every size: (1) cannot get the employees they need to grow their business because the U.S. labor force has millions fewer workers available than it had in 2019;<sup>195</sup> (2) cannot get goods and materials they need on time, because supply chains have failed; and (3) must pay more for the goods and materials they buy, and the fuel, electricity, and other sources or forms of energy they need to operate, as inflation roars. However, the commenter states that the EPA has responded with the new proposal for more burdensome and costly regulations on the oil and gas industry, which they contend will hike the cost of regulatory compliance for the regulated oil and gas businesses and will hike the cost of energy for all businesses.

Commenter (0946-MOGA) questions the EPA's use of 2019 emissions data to justify the current proposed regulations. Based on historic rulemaking efforts, if the full implementation of Subpart OOOOa did not begin until roughly 2018 (considering the 2-year & 90-day court stay), how can the EPA determine the effectiveness of the NSPS OOOOa regulations and justify the new proposed regulations? As shown in the emissions reduction tables in Comment #2 of the commenter's letter, Michigan producers have been successful in reducing emissions through NSPS OOOO and NSPS OOOOa regulations. The commenter reports that the three small businesses illustrated in the commenter's letter in the emissions reduction tables have invested significant capital to achieve emissions reductions without the EPA allowing enough time to recover costs. Based on this data, the commenter believes that the EPA should allow more time to evaluate current regulations applied to new sources and future modifications of previously non-regulated sources before amending regulations resulting in another substantial economic burden on small business producers.

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<sup>195</sup> Federal Reserve Bank of St. Louis, Civilian Labor Force Level (CLF160V), available at <https://fred.stlouisfed.org/series/CLF160W> (visited November 16, 2021) (size of labor force in 2019 and 2021).

Response I-20-37: With respect to supportive comments, EPA agrees that the rule will reduce methane and VOC emissions from oil and natural gas operations in the United States.

In response to commenter who argues that EPA's approach and regulations will have a devastating effect on small independent producers and private landowners who are paid royalties for their minerals to continue to operate, which will also impact the economy of the State of Michigan itself, the commenter did not provide specifics to support their position. Please see comments and responses provided to comments in section 20.2.7 (Impact on Small Business) for similar concerns expressed by small businesses.

In response to comment that most of the gas that is not being sold today costs too much for owners and operators to collect, process, transport, and sell into the natural gas market, the EPA acknowledges that this is a practical reality. In fact, the final rule provisions address that practical reality for associated gas wells at well affected facilities in the required infeasibility demonstration and certification provisions applicable to situations where routing the associated gas to a sales line, using it as onsite fuel or for another beneficial purpose, or injecting/reinjecting is not feasible. See section XI.F.2.g (Infeasibility demonstration and certification) for discussion of the infeasibility demonstration and certification provisions in the final rule. It is also important to know that the calculated gas savings estimated by the EPA illustrate the potential for gas savings of varying regulatory options being considered but are not used as a determinant of what constitutes BSER. Notably, the EPA also acknowledges that this offset would not apply where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.*, transmission stations and storage facilities).

In response to the commenter that states that NSPS OOOOa is already effective at regulating new sources and achieves the goals of reducing emissions on the largest known source of emissions (new sources with high production), in addition to providing regulatory coverage of modified existing facilities with new emission sources, the EPA agrees that NSPS OOOOa has been effective. However, greater emissions reductions of VOC and methane emissions are needed. As discussed in the final rule preamble, these final actions stem from the EPA's authority and obligation under CAA section 111 to directly regulate categories of new stationary sources that cause or contribute to endangerment from air pollution and to promulgate EG for states to follow in regulating existing sources (designated facilities) in the source category. See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

In response to comment concerned that America depends upon affordable oil products and natural gas for the energy that keeps the American economy going and that the EPA's proposed rules will only add to burdensome and costly regulations on the oil and gas industry will result in a hike of the cost of energy for all businesses, the variables that contribute to the cost of oil products and natural gas is influenced less by regulations than by other factors (*e.g.*, taxes, OPEC production, consumer demand, refinery capacity). Nonetheless, the EPA evaluated and streamlined compliance and recordkeeping and reporting requirements, where feasible, and included multiple compliance alternatives for several affected facilities/designated facilities

under the final NSPS OOOOb and EG OOOOc rules. See section X (Summary of Final Standards NSPS OOOOb and EG OOOOc) of the final rule preamble for a summary of the final standards/presumptive standards.

### ***20.3.2 Emissions Data/Verification/Analyses***

Comment: Commenter (0426-League of Women Voters of New Jersey) suggests that in order to properly evaluate our current situation regarding methane emissions from upstream gas and oil facilities and to determine if the proposed abatement rules are effective, the commenter recommends that the EPA undertake an analysis of recent peer-reviewed studies on emissions from gas and oil extraction, transportation, processing (including separation, liquefaction and refining), distribution and use. After carrying out any further studies deemed absolutely necessary, the EPA should promulgate this data so that all our country's scientists are using the same basic data. Workers at gas extraction, processing and pipeline facilities need to know how to measure emissions on their sites and compare them with EPA data.

Response I-20-38: EPA acknowledges the commenter's input. The EPA reviewed available data during the course of this rulemaking, including data submitted by commenters. Additionally, the EPA has recently taken up multiple rulemakings, including NSPS OOOOb, revisions to 40 CFR part 98 subpart W (greenhouse gas reporting rule), and the Methane Emissions Reduction Program, which will also generate data to better quantify emissions from this sector. NSPS OOOOb and EG OOOOc include required methods for measuring emissions from various sources, such as control devices on affected facilities, in the final rulemaking.

Development and promulgation of a database of oil and natural gas studies and emissions database are beyond the scope of the final rulemaking and this document.

Comment: Commenter (0941-350 Silicon Valley) recommends that the EPA assume responsibility for verifying methane emissions data reported to the U.S. government by states and companies and work with the National Aeronautics and Space Administration (NASA), DOE, National Oceanic and Atmospheric Administration (NOAA) and the Bureau of Land Management (BLM) to set up a system for verifying methane emissions from the oil and gas industry. The commenter further recommends that EPA seek to include more funding in the Build Back Better bill for the collection and analysis of satellite GHG emissions data (especially methane, carbon dioxide, and nitrous oxide), and to establish a federal inter-agency group to develop better estimates of methane emissions.

Response I-20-39: EPA acknowledges the commenter's input. Funding data studies and interagency workgroups are beyond the scope of this final rulemaking and this document.

Comment: Commenter (0768-MR) states that emissions data are particularly important in this rulemaking because of the role and nature of advanced technology for detecting and measuring emissions, particularly high volume, intermittent sources. To achieve the common goal of a transparent regulatory framework that facilitates efficient and effective enforcement and compliance, the commenter suggests that EPA take comment on ways it can encourage the submission of emissions data for compliance purposes. For example, they suggest that EPA take

comment on the cost and feasibility of collecting emissions estimation data and direct measurements from leak detection surveys. According to the commenter, doing so would allow EPA to take advantage of emissions data that is more readily available from advanced technologies while ensuring the reporting requirements do not create a disincentive to adopt these technologies.

The commenter (0768-MR) suggests that, as data improve and become more robust, they can serve several purposes beyond compliance assurance. Data can be used to periodically update emissions simulation models and technology testing protocols to better reflect what is known about emissions distributions. In turn, that will facilitate identification of new monitoring technologies and methodologies. And, in the longer term, improved data may enable EPA or states to add, clarify, or update an emission performance standard.

The commenter (0768-MR) adds that the EPA could also provide improved data on emissions and technology advancements to help states develop their CAA 111(d) plans. Finally, they suggest that the emissions data can be used to improve EPA and state GHG inventories. The commenter provides that the EPA has already proposed that calculation of well site annual emissions should incorporate any updates made to inventory emissions factors. However, the commenter states that the EPA should also consider whether and how data gathered under EG OOOOc and CAA 111(d) plans might be incorporated into GHG inventories including Subpart W of the federal GHG Reporting Rule. They stress that it is important for EPA to recognize the value of this CAA 111 rule as an advanced technology data gathering mechanism and to ensure that data gathered from this CAA 111 rule are used to inform future Subpart W changes.

Thus, the commenter (0768-MR) recommends that EPA address or seek input on the following in the Supplemental Rule Proposal:

- How can monitoring data from advanced technologies be used to streamline and improve compliance?
- How can emissions data be used to evaluate the rule's effectiveness in meeting the U.S.'s emission reduction goals?
- What incentives can EPA offer to operators to provide emissions data that will support evaluations of overall rule effectiveness, inform emissions simulation models, and improve greenhouse gas inventories?
- What data would EPA need from industry and other stakeholders to ultimately support development and use of an emissions performance standard in state plans, including a methane intensity standard?
- How should EPA consider emissions data developed by oil and operators subject to the rule compared to data developed by third parties (including community organizations)?

Response I-20-40: EPA acknowledges the commenter's input. In the December 2022 Supplemental Proposal, EPA took comment on the required reporting for owners and operators who use advanced methane detection technologies to conduct inspections for fugitive emissions. EPA received comment from various stakeholders on the use of advanced methane detection technologies in response to that proposal. See Volume II, Chapter 5 for responses to comments on advanced methane detection technologies.

For discussion on emissions distributions and the modeling conducted to develop the periodic screening matrices used for advanced methane detection technologies, see section XI.B.1.a of the preamble to the final rule. Clean Air Act Section 111 requires that at least every 8 years, the EPA review and, if appropriate, revise standards of performance for regulated NSPS sources. EPA may use the data collected from this rulemaking, including data that owners and operators submit from fugitive emissions periodic screenings or continuous monitoring using advanced methane detection technologies, in a future review process.

EPA will evaluate data submitted both by oil and gas operators and third parties to determine whether the data meets the data quality objectives for the purpose for which it is used. By requiring owners and operators, as well as third parties who submit data under the super-emitter program, to use methods approved by EPA, we have taken steps to ensure all data submitted to the agency as a result of this final rulemaking will meet a minimum level of data quality.<sup>196</sup>

EPA notes that it has outlined the requirements for state plans in EG 0000c.

Development of emission inventories, including those under 40 CFR part 98 subpart W, are outside the scope of the final rulemaking and this document.

Comment: Commenter (0800-UPLP) asserts that, because the development of this standard is reliant on determining emission thresholds, the commenter requests that EPA provide support to create consistent guidelines for how to estimate emissions for development of an oil and gas emission inventory for VOCs.

Response I-20-41: Development of emission inventories are outside the scope of the final rulemaking and this document.

### ***20.3.3 Impacts of the Proposed Regulations on Existing Contracts***

Comment: Commenter (0946-MOGA) states that the EPA did not solicit comments from the oil and gas production industry and small businesses or attempt to understand the potential impacts of the proposed regulations on existing contracts. The commenter explains that, before a well is drilled or a facility is constructed, surface and underground asset contracts are prepared and presented to the landowners for review, discussion, modifications, and final authorization. These contracts allow the potential producing company to enter the property for review, acknowledgement of the complication in the terrain and apply for additional permits and contracts, negotiate with the landowner for mineral rights, access fees and mineral distributions. Additional contracts with utilities, transportation companies, pipeline operators and regulators are prepared, reviewed, and signed before a well is drilled and determined to be commercial and viable. All the above-mentioned contractual obligations becomes null and void if the well is not economically sustainable. The commenter believes that the EPA needs to address the potential costs and problems associated with breach of contract before expanding regulations to existing sources. Further, the commenter recommends that the EPA include these costs and ramifications

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<sup>196</sup> Advanced methane detection technology used for both fugitive emissions inspections and the super-emitter program must be approved by EPA in accordance with 40 CFR 60.5398b(d).



into their cost per ton of methane reduction to adequately represent the true costs of imposing future regulations on the industry.

Response I-20-42: The EPA does not agree with the commenter that potential costs and problems associated with breach of contract ought to be considered in the EPA's cost per ton analysis for existing sources. This comment is too general for the EPA to fully evaluate the merits of the commenter's claim. The commenter appears to assume that EPA's final EG will somehow make some wells "not economically sustainable." The commenter does not explain what this phrase is intended to convey or how the EPA's EG will supposedly do this. The EPA finds this claim to be speculative and unsupported by the commenter.

It is unclear to the EPA exactly how the commenter suggests it should have done so. Commenter neither provides any specific data or analysis to support its argument, nor explains how any such analysis might have affected the EPA's establishment of standards of performance. It is unclear to the EPA how any analysis of contracts would have influenced the final rule.

#### ***20.3.4 European Union Intensity Standards – Liquid Natural Gas Exports***

Comment: Commenter (0912-Shell) states that believes that these methane control requirements generally reflect best available control measures that are generally aligned with any methane intensity target considered by the European Union in the future for the upstream segment of the natural gas supply chain in the U.S. Based on these methane control requirements, oil and gas producers, liquid natural gas (LNG) traders, and shippers would not have to add another layer of verification to prove that their natural gas meets the European Union intensity standard. Without an equivalence – if the European Union proceeds with an emissions intensity standard – demonstrating compliance with that standard to upstream emissions could potentially put U.S. LNG exports at a competitive disadvantage because the only possible way to avoid financial penalties would be through costly and potentially unworkable added monitoring, reporting and verification (MRV) schemes that could require tracing of natural gas molecules from individual producers along complex natural gas delivery chains.

Response I-20-43: EPA acknowledges the supportive comment.

## Chapter 21. Statutory and Executive Order Reviews

### 21.1 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Comment: Commenter (0831-American Exploration and Production Council (AXPC)) references and incorporates comments made and submitted to EPA on the November 2021 Proposal (*i.e.*, OMB-2021-0006-0087), which the commenter notes, “estimates benefits from the methane emission reductions it projects this rulemaking will cause by using the interim social cost of methane estimates contained in the February 2021 publication from the Interagency Working Group (86 Fed. Reg. at 63,258/3).” According to the commenter, remarks made varied but included comments on the importance of “communicating the significant uncertainties within the estimates and limiting their use to regulatory impact analysis pursuant to interagency review under [EO 12866].”

Response I-21-1: As discussed in section XVI.E (What are the benefits?) of the final rule preamble, the EPA is a member of the Interagency Working Group (IWG) and is participating in the IWG’s work under E.O. 13990. While that process continues, as noted in previous EPA RIAs, the EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. In the RIA for the December 2022 Supplemental Proposal, the EPA included a sensitivity analysis of the climate benefits of the supplemental proposal using a new set of SC-GHG estimates that incorporates recent research addressing recommendations of the National Academies of Science, Engineering, and Medicine (2017), in addition to using the IWG recommended interim SC-GHG estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, published in February 2021 (IWG, 2021).

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the December 2022 Supplemental Proposal to ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the agency on its development of this update, calling it a much-needed improvement in estimating the SC-GHG and a significant step towards addressing the National Academies’ recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated into the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA’s response to each recommendation is available on EPA’s website. The EPA is a member of the IWG on the SC-GHG and continues to participate in its work. The EPA’s new SC-GHG estimates along with the

peer review of the updated methodology will be among the many technical inputs available to the IWG as it continues its work.

An overview of the methodological updates incorporated into the new SC-GHG estimates is provided in the final RIA. A more detailed explanation of each input and the modeling process is provided in the technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* (EPA 2023), which is also included as supporting material for the final RIA in the docket.

Comment: Commenter (0797-North Dakota Department of Environmental Quality (NDDEQ) and North Dakota Industrial Commission (NDIC)) disagrees with EPA's use of EO 13990 and EO 12866 (e.g., Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under EO 13990 or IWG 2021 support document) as justification for issuing the November 2021 NSPS Proposal as a whole, but more specifically in justifying their quantification of the "social cost of carbon." The commenter suggests that the EPA acted beyond its authority; stating that "EPA's authority to promulgate NSPS regulations must be based on its statutory authority under the Clean Air Act as authorized by Congress," which the commenter underscores "cannot be expanded or amended" by Presidential orders. Specifically, the commenter maintains that the EPA cannot justify "costs that will be imposed on American citizens and businesses if the November 2021 NSPS Proposal was finalized by trying to balance those costs against speculative global benefits that might be reaped outside of the United States using the very dubious 'social cost of carbon' calculations directed by EO 12866." The commenter contends that courts have already rejected arguments/claims made that use or rely on "global benefits" to justify national costs/impacts. To further illustrate their point the commenter references a small number of court rulings and other failed attempts made by federal agencies to use "global benefits" as justification for domestic impacts – e.g., *Wyoming et al. v. Jewell et al.* [See Chapter 20. Emissions and Regulatory Impacts of this document for additional comments on the use of "global benefits" as justification for domestic impacts.]

Response I-21-2: See Response I-21-1 of this Chapter.

## **21.2 Paperwork Reduction Act (PRA)**

Comment: Commenter (0924-U.S. Small Business Administration (SBA)) states that EPA has not prepared an information collection request (ICR) for the requirements of the proposed NSPS OOOOb, EG OOOOc or Appendix K, as would be required under the PRA and 44 U.S.C. 3507(d)(1) for a proposed rule. The commenter advocates that the EPA explicitly re-open all elements of the November 2021 proposed NSPS OOOOb and EG OOOOc rules for public comment when the supplemental proposal is developed.

Response I-21-3: See the following ICR Supporting Statements located at Document ID Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO & OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc) for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. Burden associated with Appendix K is included in

the burden with natural gas processing plants which mirrors how the best system of emission reduction (BSER) was analyzed for equipment leaks at gas plants.<sup>1</sup>

## 21.3 Regulatory Flexibility Act (RFA)

Comment: Commenter (1341-Pennsylvania Grade Crude Oil Coalition (PGCC) *et al.*) notes that pursuant to RFA section 609(b), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), EPA convened a Panel including EPA's Small Business Advocacy Chairperson, to discuss the effects of EPA's November 2021 Proposal on small businesses. The commenter reports that after considering the information given to it by EPA and various small entity representatives (SERs) in the oil and gas sector, the Panel issued a final Panel Report containing various recommendations to EPA regarding its November 2021 Proposal. Unfortunately, according to the commenter, EPA has failed to consider and/or meaningfully address several key observations and recommendations.

Response I-21-4: The EPA disagrees with the commenter's assertion. Please see the complete IRFA is available in the RIA for the December 2022 Supplemental Proposal (see section 4.3 of the RIA), the summary of the FRFA section XVII.C. of the final preamble, and section 4.4 of the final RIA.

Comment: Commenter (0924-SBA) suggests that EPA fails to comply with the requirements of the RFA, because it failed to adequately account for or consider the economic impact of proposed Appendix K or include any consideration of the burdens due to the November 2021 proposed NSPS OOOOb. The commenter contends that the RFA requires EPA to consider the potential impact of its proposed rules on small entities, and further claims that the November 2021 Proposal initial regulatory flexibility analysis (IRFA) accompanying this rule lacks a sufficient discussion of regulatory alternatives that would minimize the impacts on small businesses.

For instance, the commenter (0924-SBA) states that in the quantification of the burden, EPA provides only the burden of NSPS OOOOa, not the proposed new NSPS OOOOb. Additionally, the commenter notes that EPA only provides an average across the next three years, which, according to the commenter is not sufficient to describe the burden of the proposed requirements for purposes of an IRFA, particularly when a requirement is phased in. The commenter recommends that EPA reevaluate the total economic impacts on small entities and prepare a new IRFA.

Response I-21-5: In the December 2022 Supplemental Proposal, EPA did not require optical gas imaging (OGI) monitoring in accordance with the proposed Appendix K for well sites or centralized production facilities, as was proposed in the November 2021 Proposal. In the December 2022 Supplemental Proposal, EPA proposed that equipment leaks at gas plants are monitored using OGI in accordance with Appendix K.<sup>2</sup> Burden associated with Appendix K is

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<sup>1</sup> 86 FR 63232.

<sup>2</sup> 87 FR 74807.

included in the burden with natural gas processing plants which mirrors how BSER was analyzed for equipment leaks at gas plants.<sup>3</sup>

See the following ICR Supporting Statements located at Document ID Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO & OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc) for this action located at Docket ID No. EPA-HQ-OAR-2021-0317.

Pursuant to section 603 of the RFA, EPA prepared an IRFA that examined the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. Please see the complete IRFA is available in the RIA for the December 2022 Supplemental Proposal (see section 4.3 of the RIA), the summary of the FRFA section XVII.C. of the final preamble, and section 4.4 of the final RIA.

Comment: Commenter (0924-SBA) believes that repeating SBREFA's panel report recommendations without change is insufficient to satisfy the requirement – the IRFA “contain[s] a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities” – further arguing that the SBREFA panel report does not reflect the issued November 2021 Proposal. The commenter maintains that EPA's responsibility to identify significant regulatory alternatives for the IRFA does not end with the conclusion of the SBREFA panel, particularly when there are significant changes during and after the SBREFA panel consultations. To illustrate their point, the commenter notes, for this rule, EPA developed new regulatory alternatives for monitoring requirements, liquids unloading, and pneumatic controllers that became EPA's preferred alternative, which the commenter writes could reduce the impact on small entities, are not reflected in the IRFA. The commenter underscores the point that while regulatory alternatives are discussed in the *Federal Register*, they are not referenced in the IRFA, nor are they mentioned in response to the panel's recommendations.

In a similar point, commenter (0924-SBA) believes that a re-statement of SBREFA's panel report recommendations, particularly where panel members disagree, is not the same as an analysis and reasoned consideration of alternatives. Specifically, the commenter feels that it is insufficient to adopt verbatim the alternatives section of the panel's report as the description of alternatives required in the IRFA. Although the commenter acknowledges that EPA is correct to incorporate new information into its November 2021 Proposal and analysis as it is developed, and the commenter does not expect a proposed rule or analysis to be in its final form during the conduct of a SBREFA panel. According to the commenter, however, such a change should be accompanied by changes in the IRFA to reflect the availability and consideration of different regulatory alternatives. The commenter insists that EPA issue a revised IRFA to include alternatives reflective of the November 2021 Proposal and supplemental proposed rule.

Response I-21-6: Pursuant to section 603 of the RFA, EPA prepared an IRFA and FRFA that describes the economic impact of the proposed and subsequently final rule on small entities and the steps taken to minimize the significant impact on small entities consistent with the stated objectives of applicable statutes. EPA also examined regulatory alternatives that could minimize

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<sup>3</sup> 86 FR 63232.

that impact. Please see the complete IRFA available in the RIA for the December 2022 Supplemental Proposal (see section 4.3 of the RIA), the summary of the FRFA section XVII.C. of the final preamble, and section 4.4 of the final RIA.

Comment: Commenter (0924-SBA) maintains that there are significant gaps in EPA's RFA and advise EPA to prepare a revised RFA, along with a revised IRFA to reflect the entirety of the November 2021 Proposal and supplemental proposal. The commenter supports the use of supplemental proposed rules to remedy gaps in the record; however, in this case, the commenter argues that the supplemental proposal will serve more as a proposed rule than a simple supplemental. According to the commenter, EPA has committed to publishing a supplemental proposal for this rulemaking because it recognizes that the record to support this rule is incomplete. The commenter suggests that EPA has issued a proposed rule without providing rule text for the proposed NSPS OOOOb and proposed EG OOOOc.

Response I-21-7: The EPA prepared a revised IRFA for the December 2022 Supplemental Proposal. The complete IRFA is available for review in the 2022 RIA (see section 4.3).<sup>4</sup> Please see the summary of the FRFA section XVII.C. of the final preamble, and section 4.4 of the final RIA.

## **21.4 Unfunded Mandates Reform Act (UMRA)**

Comment: Commenter (0797-NDDEQ/NDIC) does not believe that EPA could reasonably make the calculation that the November 2021 Proposal “does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and Tribal governments, in the aggregate or the private sector in any one year” in accordance with UMRA when EPA has not proposed regulatory text. 86 Fed. Reg. at 63,260. In the RIA cited for that calculation, EPA concedes that for evaluating the regulatory actions “[w]e do not analyze the regulatory impacts of all proposed requirements because we either do not have sufficient data or because it is assumed the provisions would not result in compliance cost or emissions impacts; in these instances, we qualitatively discuss the proposed requirements.” See Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, at 1-4. The commenter adds that EPA also acknowledges that state programs have varying requirements but then proceeds to select California and Colorado as a baseline to evaluate other state programs. See *id.* at 2-29 (noting that “California and Colorado have requirements at least as stringent as those in the proposed rule for well site and compressor station fugitives; natural gas processing plant leaks; pneumatic controllers; pneumatic pumps in the production, gathering and boosting, and processing segments; pre-OOOO reciprocating and wet-seal centrifugal compressors in the gathering and boosting and processing segments; and storage vessels”). The commenter notes that this is based in part on EPA's assumption that “California and Colorado have requirements at least as stringent as those in the proposed rule” and that they “contribute significantly to national production levels” for the oil and gas industry. *Id.* at 2-29. The commenter believes that the conclusion that California and Colorado are good and representative models for the costs of the November 2021 NSPS Proposal and as the baseline to evaluate other

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<sup>4</sup> Document ID No. EPA-HQ-OAR-2021-0317-1566.

state programs is arbitrary and fails to take into account the actual oil and gas production sector in the United States. The commenter believes EPA cannot fairly characterize the costs in the absence of an actual proposed rule, and in any event has underestimated the compliance costs that states will incur in developing the required EG plans for OOOOc. The RIA does not appear to have sufficient data to accurately calculate these costs and the baseline data that is biased. Overall, in both the proposed rule and related RIA, EPA downplays the burden of developing these plans.

Response I-21-8: See discussion in section VIII.D. of the December 2022 Supplemental Proposal<sup>5</sup> and section XVII.D of the final preamble. See the proposed regulatory text for NSPS OOOOb at Document ID No. EPA-HQ-OAR-2021-0317-1551 and EG OOOOc at Document ID No. EPA-HQ-OAR-2021-0317-1552 in the public docket. See the following proposed ICR Supporting Statements located at Document ID Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO & OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc) and the final ICR Supporting Statements for this rulemaking located in Docket ID No. EPA-HQ-OAR-2021-0317.

As to the comments regarding EPA's representation of state regulations in California and Colorado in the RIA, EPA believes the commenter has misunderstood the meaning of the RIA baseline. EPA is not using California and Colorado as baselines to evaluate other state regulations as the commenter asserts. Rather, due to the analytic difficulties in accounting for state regulations in the baseline scenario in the RIA, EPA broadly assumes that California and Colorado have equivalent or more stringent regulatory requirements to those in the November 2021 Proposal to avoid attributing emissions reductions in those states to the proposed action, as they would have happened regardless of any action taken by EPA. Thus, EPA's purpose in accounting for the California and Colorado requirements in the RIA baseline is to generate a more accurate estimate of the impacts of the rule rather than to use as a basis to evaluate other state programs.

Comment: Commenter (0824-Wyoming Department of Environmental Quality (WDEQ)) states that the November 2021 Proposal's expansion of the scope of affected facilities creates an unfunded mandate and infeasible resource burden upon the WDEQ. The commenter states that Wyoming's role as a nationally prominent producer of oil and natural gas means that the November 2021 Proposal places heightened burdens upon the Division's staff and financial resources compared to many other affected states in other parts of the country. As of August 2021, the commenter states Wyoming ranked eighth nationally in oil production and for the 2020 calendar year, Wyoming ranked ninth in marketed production of natural gas. Furthermore, the commenter adds that Wyoming has 16 of the nation's 100 largest natural gas fields, including the Pinedale and Jonah fields that rank among the top 10. Wyoming exercises air quality primacy and all areas in the State are meeting ambient air quality standards; through its Air Quality Division (AQD), it exercises substantial regulatory authority over the operations of Wyoming's extensive oil and gas industry. For example, the commenter reports that the WDEQ program covers over 18,000 operating single well sites and compressor stations. According to the commenter, while standing alone, the number of these sites is daunting, it barely begins to

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<sup>5</sup> 87 FR 74844.

account for the massive increase in specific equipment subject to the November 2021 Proposal such as pneumatic pumps and controllers.

As such, the commenter (0824-WDEQ) reports that the November 2021 Proposal imposes compliance assurance costs on Wyoming without providing the funding to meet the additional federal regulatory burdens. For more than a decade, the commenter indicates that federal funds have only provided about 7 percent of the WDEQ's budget, with the rest coming from operator-paid fees or the State's General Fund. The commenter contends that, with the additional costs that will be imposed on Wyoming to implement the November 2021 Proposal, the proportion of federal funds will be further decreased, and the burden shifted to Wyoming's citizens and industry to shoulder the difference.

Commenter (0824-WDEQ) expresses that these costs would be of a magnitude that is simply unworkable for the Wyoming AQD (and likely other state regulatory agencies in the country) with no significant environmental outcomes. The commenter notes that the requirements pertaining to fugitive emissions monitoring and repair programs, including monitoring for fugitive emissions with OGI in accordance with 40 CFR part 60, Appendix K, would impose a massive reciprocal workload for state agencies. According to the commenter, conducting the compliance inspections, reports, and emissions inventories work commensurate with the requirements of the November 2021 Proposal places an overwhelming strain on agency staff and financial resources. The commenter contends that the skyrocketing workload would require hiring additional full-time employees (FTE), as well as training costs, equipment costs, and other associated costs.

The commenter (0824-WDEQ) presents potential state agency burdens that would be associated with the November 2021 Proposal but notes that it is impossible to pin down specific costs to the agency to fulfill the compliance demands of the November 2021 Proposal because EPA failed to provide specific regulatory language. However, the commenter notes that the increase in the number of facilities that would be affected, a general idea of some of the inspection requirements, and associated training costs, equipment costs, travel costs, and other costs, it is reasonable to assume the agency would have to hire significantly more staff. The commenter notes that the associated cost of hiring even five additional staff (one of whom would be at a senior level) would cost the agency \$585,458.67 annually. These estimates, according to the commenter, coupled with the costs identified above, would impose an immediate financial burden on the agency of about \$1,985,450, which does not account for recurring annual employee costs, recurring equipment maintenance and update costs, recurring future travel costs, *etc.*<sup>6</sup>

Commenter (0824-WDEQ) states that, despite proposing requirements that will certainly impact state agencies, EPA did not provide any information on anticipated implementation costs. The commenter contends that there is no way of providing a precise estimate for costs to WDEQ associated with the November 2021 Proposal. However, the commenter suggests that the financial demands placed on states under the November 2021 Proposal would require significant

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<sup>6</sup> Cost statistics regarding FTE/additional FTE provided by WDEQ's Administration Division; cost-estimates regarding compliance duties associated with the November 2021 Proposal provided by AQD's Compliance Program.



additional funds. The commenter expresses concern that EPA has proposed no funding for the states to implement this expansive federal mandate. The commenter recommends that, if EPA expects the WDEQ to carry out these comprehensive compliance requirements, it is imperative that the federal government provide funding that would cover the entirety of the staffing and resource demands that they will experience. Otherwise, the commenter asserts that the November 2021 Proposal's requirements are unlawful, overly burdensome, and utterly impracticable.

Similarly, commenter (0580-Kentucky Division for Air Quality (KDAQ)) states that, as the delegated authority in Kentucky, the Division is responsible for the implementation and enforcement of both the new and existing rules once adopted into Kentucky law. The commenter reports that the Commonwealth has an estimated 60,000 sources that may become subject to the changes in the November 2021 Proposal. According to the commenter, the November 2021 Proposal creates an enormous unfunded mandate for the Division, as additional funding is not proposed to accommodate these additional responsibilities.

Commenter (0763-Texas Commission on Environmental Quality (TCEQ) and Railroad Commission (RRC)) asserts that the November 2021 Proposal constitutes an unfunded mandate that will dramatically impact oil and gas producing states. The commenter states that, for oil and gas producing states, costs will increase, while non-oil and gas producing states and the federal government will not see increases in regulatory or product cost. The commenter notes that, from a regulatory perspective these rules will significantly increase the permitting, investigation, and enforcement workload for the commenter (0763-TCEQ/RRC) as the delegated administrator. The rules will greatly increase the number of regulated facilities throughout the state and will also increase the number of records and reports that will be required to be reviewed to ensure compliance during an associated investigation. The commenter adds that the implementation of the November 2021 Proposal will dramatically increase the fiscal burden on Texas and will likely adversely affect delegated administrators across the nation with similar oil and gas production activity.

Response I-21-9: The new standards will work hand-in-hand with new resources and programs in the Inflation Reduction Act, which will incentivize early implementation of innovative methane reduction technologies and support methane mitigation and monitoring activities. These efforts will achieve greater methane emissions reductions more quickly. For more information on the IRA, the Administration has created a guidebook that provides an overview of the clean energy, climate mitigation and resilience, agriculture, and conservation-related tax incentives and investment programs, including who is eligible to apply for funding and for what activities. See <https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/>

EPA does intend on working with states to develop plans tailored to the factors concerning the states. The state-plan developing process, under which states establish performance standards for existing sources within their jurisdiction and have the discretion to consider remaining useful life and other factors, is one that Congress established through the text and structure of CAA section 111(d).

See the following proposed ICR Supporting Statements located at Document ID Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO & OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS

OOOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOOb) and the final ICR Supporting Statements for this rulemaking located in Docket ID No. EPA-HQ-OAR-2021-0317.

## **21.5 Executive Order 13132: Federalism**

Several commenters assert that the November 2021 Proposal does not provide sufficient respect to federalism considerations. Some of the specific concerns and comments received are presented in the following paragraphs.

Comment: Commenter (0573-Kansas Department of Health and Environment (KDHE)) argues that the November 2021 Proposal is flawed because it pertains to state implementation of the proposed EGs without adequately considering costs to the states to implement the guidelines for existing sources; adding that the preamble and the 2021 RIA for the November 2021 Proposal fail to correctly account state compliance costs. Furthermore, the commenter insists that the November 2021 Proposal by EPA to offer “aid and guidance” in an effort to correct for the anticipated “federalism implications” is not an acceptable substitute for adequate funding needed for this proposed federal initiative being imposed upon the state [86 FR 63260]. The commenter expresses concern that the proposed EGs would heavily impact their state of Kansas; pointing out, for example, that there are approximately 78,000 active oil wells and 28,000 active natural gas (including coal bed methane (CBM)) wells within the state and 93 of the 105 counties (in Kansas) have oil and gas well activity.

Commenter (0581-National Association of Clean Air Agencies (NACAA)) warns that state and local air pollution control agencies tasked with implementing and enforcing EPA’s rule will face a great variety of challenges – *e.g.*, increase their investments in personnel and technical capabilities, and urges the Agency to ensure that new burdens are paired with supplemental federal support and that they not come at the expense of resources already allocated for existing air programs. While the commenter recognizes agencies will be impacted differently – based on the number of sources within their authority – the commenter suggests that all agencies are presently facing resources and labor changes trying to meet their existing and emerging CAA responsibilities. The commenter warns that these resource and labor change issues will only increase unless agencies have federal support – *e.g.*, EPA ensures that agencies are appropriately funded.

Commenter (0581-NACAA) suggests that EPA can also help manage [federalism] implementation burdens by prioritizing and phasing its requirements under the rule to consider what the most resource-intensive actions are, and by balancing those actions with those that have the greatest demonstrated public health and environmental benefit. The commenter maintains that the speed and the order of the implementation steps must match the demonstrated availability of technologies and account for ongoing supply chain disruptions and labor issues. Additionally, the commenter points out that while sources such as pigging, truck unloading, small well sites are important and can have significant emissions, offering states flexibility for phasing in regulatory programs addressing them could potentially be valuable as a strategy to manage regulatory burdens. Although the commenter appreciates the November 2021 Proposal’s consideration of a number of new tools, programs and approaches, they note that those measures will take time to learn. Consequently, the commenter recommends that EPA should focus its

technical assistance efforts at addressing that learning gap. Additionally, the commenter writes, achieving shared goals for emission reductions may also be more successful if EPA prioritizes compliance assistance over example-setting enforcement in early years.

Response I-21-10: See Response I-21-9 of this Chapter. See also discussions on the timing of state plan submittals and compliance timelines in section V.D. of the December 2022 Supplemental Proposal Preamble,<sup>7</sup> and section XIII.E. of the final preamble.

Comment: Commenter (0946-Michigan Oil and Gas Association (MOGA)) expresses concern that associated costs from unfunded federal programs imposed on state agencies via “federalism” might be passed on to oil and gas producers in each state. The commenter supports EPA’s decision to allow individual state’s primacy over EGs. The commenter adds that wells are typically permitted, monitored, *etc.* on a local and/or state level, which, according to the commenter, allows for prompt changes, modifications, or community intervention, if needed, at these sites. The commenter notes that this is in contrast to federal inspections and correspondence.

Response I-21-11: Please see section IV.A of the final preamble discussing statutory background of CAA sections 111(b), 111(d), and general implementing regulations. Please see section XIII of the final preamble discussing the implementation framework of EG OOOOc.

Comment: Commenter (0797-NDDEQ/NDIC) notes that EPA solicited comment in the November 2021 Proposal on the costs associated with developing and submitting state plans for EG OOOOc. 86 Fed. Reg. at 63,261 (EO 13132 (Federalism)). However, the commenter contends that it is not reasonable to expect commenters to evaluate the cost of implementing a rule when EPA has not proposed rule text. Without the regulatory text of the rule itself (*i.e.*, what EPA proposes to publish in the Code of Federal Regulations), the commenter states that they do not know what it will have to do nor what it will cost. The commenter adds that, when EPA, consistent with its obligations under the Administrative Procedures Act (APA), publishes a proposed rule for comment, they will be able to evaluate the likely costs of the proposal.

Response I-21-12: See the proposed regulatory text for NSPS OOOOb at Document ID No. EPA-HQ-OAR-2021-0317-1551 and EG OOOOc at Document ID No. EPA-HQ-OAR-2021-0317-1552 in the public docket. See the following ICR Supporting Statements located at Document ID Nos. EPA– EPA-HQ-OAR-2021-0317-0144 (OOOO & OOOOa), HQ–OAR–2021–0317–1556 (OOOOb), EPA–HQ–OAR–2021–0317–1553 (OOOOc) for this action located at Docket ID No. EPA– HQ–OAR–2021–0317. See the final ICR Supporting Statements for this rulemaking located in Docket ID No. EPA-HQ-OAR-2021-0317.

Comment: Commenter (0790-West Virginia Office of the Attorney General (WV AG) *et al.*) asserts that the CAA expects that EPA’s regulatory efforts will show genuine respect for federalism and the role of the states. According to the commenter, the November 2021 Proposal does not.

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<sup>7</sup> 87 FR 74831.

The commenter (0790-WV AG *et al.*) explains that states already regulate natural gas production and processing. They have an interest in reducing fugitive emission of gases from natural gas processing sites. States also ensure natural gas processors keep their facilities in good repair and engage in active efforts to make sure natural gas sites are safe. See, *e.g.*, W. Va. Code § 15-5C-2(a) (requiring pipeline and well operators to report safety incidents to West Virginia Division of Homeland Security). Further, the commenter adds that states already regulate greenhouse gas emissions through permitting and other regulations. See, *e.g.*, Col. Rev. Stat. § 25-7-102, Va. Code § 45.2-1706.1. The commenter recommends that EPA further discount the minimal benefits from federal methane regulations like those in the November 2021 Proposal given state efforts like these.

According to the commenter (0790-WV AG *et al.*), even more problematically, the November 2021 Proposal imposes a series of direct burdens on the states that neither the CAA nor any other existing law permits. The commenter notes that the November 2021 Proposal identifies only one potential implication for federalism—compliance costs. The agency dryly observes that the November 2021 Proposal “may” impose a burden on the States because of the “many hours of staff time” required to develop and implement the plans that the November 2021 Proposal requires. 86 Fed. Reg. at 63,261. The commenter explains that these costs will burden states. The commenter states that the November 2021 Proposal, however, does not contain any specific provisions explaining how EPA will help states bear these significant compliance costs. And these compliance estimates may well undershoot actual costs, as other aspects of the November 2021 Proposal — such as EPA’s choice to declare any unloading event a “modification” that subjects the facility to new-source performance standards—makes it difficult to evaluate accurately the true reach of the November 2021 Proposal.

The commenter (0790/0819-WV AG *et al.*) adds that the November 2021 Proposal otherwise ignores its own consequences for federalism. As an example, the commenter provides that section 111(d) of the CAA contemplates that states will have more latitude to implement standards of performance than when EPA takes up this task—as where the statute says that states may consider a facility’s “remaining useful life.” 42 U.S.C. § 7411(d)(1). In some public statements, the commenter notes that EPA touts how the November 2021 Proposal gives the states “room” to “adopt their own approaches.” See Fact Sheet for States, EPA (Nov. 2, 2021), <https://www.epa.gov/system/files/documents/2021-11/epas-proposed-oil-and-gas-rules-information-for-states.11.2.21.pdf>. The commenter states, however, that the November 2021 Proposal says otherwise, noting how “it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities.” 86 Fed. Reg. at 63,251. The commenter suggests that, because EPA insists that the November 2021 Proposal will largely tether states to the agency’s “presumptive” standards, the states would have little choice but to implement the measures that comprise EPA’s BSER—lest EPA reject the states’ plans entirely. Even then, the commenter contends that EPA offers little reassurance to states, specifying that EPA still might not approve state plans that track the presumptive standards. *Id.* at 63,249.

Response I-21-13: EPA recognizes that some states currently regulate sources within the oil and gas industry. However, the comment is unclear regarding how this fact ought to influence EPA’s decision-making process for this rulemaking. It is unclear what the commenter is urging EPA to

do because EPA already carefully considered how states regulate these sources. Further, the need for the rule is explained in sections II and III of the final rule preamble.

The commenter claims that the proposal imposes burdens that the law does not permit, but the commenter does not identify any such burden or explain how such perceived burden conflicts with existing law. The commenter makes a broad unsupported claim. EPA has explained the legal basis for this rulemaking in sections IV and V of the final rule preamble.

EPA's statements about compliance costs came in the context of E.O. 12866.

The commenter claims that EPA's cost estimates may "undershoot" but they do not explain how or provide any details regarding costs that were unaccounted for. EPA explained its cost estimates in the final RIA and the final ICR Supporting Statements for this rulemaking located in Docket ID No. EPA-HQ-OAR-2021-0317 which are summarized in sections XVI and XVII.B of the final rule preamble, respectfully. The only example that commenters provide relates to uncertainty regarding the definition of modification for liquids unloading, but it's not clear to EPA how this would have impacts on costs to states (we are not looking at costs to industry for purposes of the Federalism EO).

Comment: Commenter (0819-WV AG *et al.*) states that the rational-basis approach set out in the November 2021 Proposal undermines the values of cooperative federalism embedded in the CAA. The commenter notes that Congress intended the Act to address air pollution while also maintaining the traditional division of authority between federal and state regulators. When Congress delegated authority to EPA to enact clean air rules, it also emphasized that "air pollution prevention ... is the primary responsibility of States and local governments." 42 U.S.C. § 7401(a)(3). This respect for state sovereignty is reflected in other parts of the statute, too. Congress assigned the critical ability to develop implementation plans for existing sources to the states—plans "which, after EPA approval, are published as regulations in the Federal Register." *People of State of Cal. ex rel. State Air Res. Bd. v. Dep't of Navy*, 431 F. Supp. 1271, 1274 (N.D. Cal. 1977), *aff'd*, 624 F.2d 885 (9th Cir. 1980). The commenter adds that the CAA repeatedly calls out the supremacy of States and local communities in controlling pollution. See, e.g., 42 U.S.C. § 7416 ("[N]othing in this chapter shall preclude or deny the right of any State or political subdivision thereof to adopt or enforce (1) any standard or limitation respecting emissions of air pollutants or (2) any requirement respecting control or abatement of air pollution."); *id.* § 7431 ("[N]othing in this chapter constitutes an infringement on the existing authority of counties and cities to plan or control land use, and nothing in this chapter provides or transfers authority over such land use.").

According to the commenter (0819-WV AG *et al.*), grafting rational basis onto the statute defies the stated principles of federalism. The commenter adds that, although the CAA imbues EPA with significant authority to set national performance standards, it is not boundless. The commenter explains that the demand to make and justify an endangerment finding for pollutants from a source category gives EPA meaningful guidelines—and preserves the states' roles while keeping the agency within its own. In short, the commenter states that a rational-basis standard gives EPA a blank check that Congress never wrote.

Response I-21-14: Please refer to RTC Volume I Chapter 3 on Significant Contribution Finding and the Congressional Review Act and final preamble section V.

Comment: Commenter (1381-Montana Petroleum Association (MPA)) reports that, at the state level in Montana, the Montana Department of Environmental Quality already has a facilities registration program in place with regular inspections using OGI cameras as well as enforcing leak detection and repair (LDAR). The commenter requests that EPA provide maximum flexibility under co-operative federalism to allow the individual states to manage the program and work with oil and gas operators on inspection technology and the related processes.

Response I-21-15: See discussions in section V.B.2.,<sup>8</sup> section V.B.3.,<sup>9</sup> and section IV.B.<sup>10</sup> of the December 2022 Supplemental Proposal. Please see sections X.A, X.B, XI.A, XI.B, and XIII.C.2 of the final preamble.

## **21.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments**

Comment: Commenters (0391-Keweenaw Bay Indian Community (KBIC), 0605-Muscogee (Creek) Nation, 0781-National Tribal Air Association (NTAA)) recognize that while environmental justices (EJ) is an important issue disproportionately impacting, for example, minority and tribal communities, EPA must never usurp Tribal sovereignty and self-determination, nor should EJ be considered a substitute to government-to-government consultation directly with Tribes. More specifically, the commenters assert that EJ actions must treat Tribes as sovereign nations with self-determination first and part of the EJ community second. Furthermore, the commenters state that EPA's baseline assessment to determine if EJ concerns exist is not a sufficient analysis with respect to considering and addressing Tribal impacts. [See Chapter 6 (Environmental Justice (EJ) Implications and Stakeholder Outreach) for additional comments on EJ considerations.]

Commenter (0794-Mandan, Hidatsa and Arikara (MHA) Nation) recalls an opportunity for Tribes to consult with EPA officials on the November 2021 Proposal during a government-to-government consultation held on January 24, 2022, during which they were assured that engagement opportunities would be ongoing. The commenter states that, as part of the ongoing consultation promised to tribal representatives, EPA should meaningfully consider, and address concerns raised by tribes up until the rule is finalized and then throughout the rule implementation process.

Commenters (0391-KBIC, 0833-Environmental Programs Department, Ute Mountain Ute Tribe (Ute EPD)) state that while they support the provision requiring states to include community engagement for accepting program delegation for the new and modified sources and as part of the program approval for state plans for existing sources, this engagement is not equivalent to consultation and coordination with neighboring Tribal Governments. According to the commenters, requiring consultation and coordination between all government entities will

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<sup>8</sup> 87 FR 74812.

<sup>9</sup> 87 FR 74816.

<sup>10</sup> 87 FR 74740.

provide more consistent understanding of the requirements, implementation, and enforcement across jurisdictions.

Commenters (0391-KBIC, 0781-NTAA, 0833-Ute EPD, 0943-Sault Ste. Marie Tribe of Chippewa Indians, Sault Tribe Environmental Department (Sault EPD)) disagree with EPA's conclusion that the November 2021 Proposal does not have Tribal implications; adding that the Agency decision is based on viewing the impacts of the Tribes with a lens of the EO alone. According to the commenters, the impacts and implications of oil and natural gas development, and the November 2021 Proposal, for Tribes are underestimated. In support, the commenters reference/cite the United Nations Declaration on the Rights of Indigenous Peoples, endorsed by the United States in 2011.<sup>11</sup>

Similarly, commenter (0605-Muscogee (Creek) Nation) states that EPA is only viewing the impacts of the November 2021 Proposal on Tribes with a lens of the EO alone. However, according to the commenter, the Agency's Indian policy and Treaty Rights policy require EPA to recognize Tribal rights, issues, and impacts beyond the EO.<sup>12</sup> The commenter notes that impacts include direct impacts to Tribal health and culture and impacts through climate change. Thus, the commenter asserts that it is important not to understate the impacts and implications of oil and natural gas development, and the November 2021 Proposal, for Tribes.

Commenter (1301-Northern Arapaho Tribe Business Council (NATBC)) states that the November 2021 Proposal has potentially significant impacts on the Tribe and requests continued government-to-government consultation regarding the Rule and any supplemental proposals pertaining to the November 2021 Proposal. The commenter also requests notification of related rules, policies, and opportunities.

Response I-21-16: See Volume I, Chapter 6 (Environmental Justice (EJ) Implications and Stakeholder Outreach), subsection 6.1.2 (Native American Environmental Justice Impacts ), Responses I-6-2 through I-6-4, for EPA's response to comments on EPA's EJ analyses.

On November 16, 2021, EPA sent a letter to all 574 Federally Recognized Tribes inviting Tribes to participate in Tribal Consultation on the November 2021 Proposal, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Three tribes requested consultation. The following consultations were held: Tribal Consultation with MHA Nation (The Mandan, Hidatsa and Arikara Nation- Three Affiliate Tribes) on January 24, 2022; Tribal Consultation with the

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<sup>11</sup> United Nations Declaration on the Rights of Indigenous Peoples, G.A. Res. 61/295, Annex, art. 32(2), UN. Doc. A/RES/61/295 (Sept. 13, 2007); Announcement of U.S. Support for the United Nations Declaration on the Rights of Indigenous Peoples, U.S. Dep't of State, <https://2009-2017.state.gov/documents/organization/154782.pdf>.

<sup>12</sup> Moreover, the United Nations Declaration on the Rights of Indigenous Peoples, endorsed by the United States in 2011, requires: "States shall consult and cooperate in good faith with the indigenous peoples concerned through their own representative institutions in order to obtain their free and informed consent prior to the approval of any project affecting their lands or territories and other resources, particularly in connection with the development, utilization or exploitation of mineral, water or other resources." United Nations Declaration on the Rights of Indigenous Peoples, G.A. Res. 61/295, Annex, art. 32(2), U.N. Doc. A/RES/61/295 (Sept. 13, 2007); Announcement of U.S. Support for the United Nations Declaration on the Rights of Indigenous Peoples, U.S. Dep't of State, <https://2009-2017.state.gov/documents/organization/154782.pdf>.

Northern Arapaho Tribe on January 24, 2022; Tribal Consultation with the Eastern Shoshone Tribe on January 25, 2022.<sup>13</sup> On November 14, 2022, EPA sent an additional letter to all 574 Federally Recognized Tribes inviting Tribes to participate in a follow up Tribal Consultation on the December 2022 Supplemental Proposal. Two tribes requested consultation. The following consultations were held: Tribal Consultation with MHA Nation on January 24, 2022, and Tribal Consultation with Ute Tribe on February 24, 2023.

EPA agrees that meaningful engagement is separate than tribal consultation. Additionally, EPA recognizes the rights of tribes as sovereign nations to self-determination and acknowledges the federal government's trust responsibility to tribes. EPA recognizes that some implications may be felt disproportionately across Indian country as well as in communities. To help resolve these, and specific to tribes, EPA provides programs, resources, financial assistance, technical assistance and training, consultation opportunities and dedicated engagement to help identify and mitigate perceived and tangible implications.

Consistent with previous actions affecting the Crude Oil and Natural Gas source category, the EPA understands there is continued significant tribal interest because of the growth of the oil and natural gas production in Indian country. In accordance with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will continue to engage in consultation with tribal officials as these rules become implemented.

## **21.7 Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use**

Comment: Commenter (0802-Kraken Oil & Gas LLC (Kraken)) suggests that EPA's November 2021 proposed actions are significant energy actions (as defined under EO 13211); arguing that these actions are based on a fundamentally flawed cost-benefit analysis that compares global benefits of methane emissions reductions with domestic cost of compliance, thereby, according to the commenter overstating domestic GHG emissions and skewing the balance in favor of the benefits of the November 2021 proposed actions for NSPS OOOOa, NSPS OOOOb, and EG OOOOc – *e.g.*, more GHG emissions than would result in the absence of regulation. The commenter defines and recaps the intent of EO 13211 and maintains that EPA does not have any basis under the CAA that would allow GHG emissions to be compared as such. As additional support, the commenter notes that Western Energy Alliance submitted comments on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" (on June 21, 2021, via Regulations.gov) in which they present their position on the purpose of the CAA regarding determining the impact from November 2021 Proposal.

Response I-21-17: Please see appendix A, section A.6 of this RTC document for EPA's response to this comment.

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<sup>13</sup> See Document ID No. EPA-HQ-OAR-2021-0317-1510.



## **21.8 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations**

Comment: Commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) seeks clarification as to why EPA believes “that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in EO 12898 (59 FR 7629, February 16, 1994)” [86 Fed. Reg. 63262], and yet it is proposing additional meaningful engagement without specific guidance for the states.

Response I-21-18: The documentation for this assessment is contained in section 4 of the November 2021 RIA and in section 4 of the 2022 RIA for the Supplemental.<sup>14</sup> See discussion in section V.B.6. of the December 2022 Supplemental Proposal pertaining to meaningful engagement.<sup>15</sup> Also see the final rule RIA and section XIII.C.6 of the final preamble.

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<sup>14</sup> See Document ID Nos. EPA–HQ–OAR–2021– 0317–0173 and EPA–HQ–OAR–2021– 0317–1566.

<sup>15</sup> 87 FR 74827.

## Chapter 22. Appendix K

The following sections provide a summary of comments received on 40 CFR part 60, appendix K (Appendix K), EPA's proposed protocol for the use of optical gas imaging (OGI) in the determination of leaks of volatile organic compounds (VOC), methane, and ethane.

### 22.1 General Support and Opposition for Appendix K

#### 22.1.1 Support for Appendix K

Comment: Several commenters (0414-Waterspirit, 0458-Maryland Department of the Environment (MDE), 0601-Connecticut Department of Energy and Environmental Protection (DEEP), 0756-Baker Hughes, 0808-American Petroleum Institute (API), 0834-Air Advocacy Coalition (A2C)) supported the development of Appendix K as a protocol for conducting OGI surveys. Commenters (0414-Waterspirit, 0458-MDE, 0756-Baker Hughes, 0834-A2C) supported the application of Appendix K for all oil and gas upstream and downstream sectors, or in specific sectors, such as gas processing and petroleum refining (0808-API). One commenter (0414-Waterspirit) urged EPA to broaden the scope to include all facilities within the oil and natural gas supply chains to provide a whole cycle assessment of methane reporting, from extraction through transmission and distribution. Another commenter (0601-DEEP) noted that Appendix K would greatly enhance the "consistency, predictability and enforceability of OGI leak detection and repair" and could serve as a model for state inspection staff to use when conducting OGI surveillance. This commenter generally supported the use of Appendix K as an alternative to EPA Method 21 monitoring and concurred that the alternative would be beneficial for states. A different commenter (0458-MDE) believes that OGI technology provides a more comprehensive survey of a facility's fugitive emissions.

Response I-22-1: EPA acknowledges the commenter's support for the development of Appendix K.

Comment: Several commenters (0749-Petroleum Association of Wyoming (PAW), 0794-Mandan, Hidatsa and Arikara Nation (MHAN), 0808-API, 0816-Montrose Environmental Group (Montrose), 0820-Pioneer Natural Resources USA, Inc. (Pioneer), 0831-American Exploration and Production Council (AXPC), 0911-North Dakota Petroleum Council (NDPC)) state that the goal of the proposed Appendix K protocol is to provide an equivalent, alternative, more technologically advanced method for leak detection and emissions reduction and a cost-effective alternative to standard EPA Method 21 leak detection and repair (LDAR) monitoring. The commenters agree that the use of OGI technology constitutes the Best System for Emission Reduction (BSER) because of its increased efficacy and because it is also cost effective, compared to traditional EPA Method 21. Further the commenters also agree that developing a protocol for OGI monitoring that includes training, survey methods, and auditing is a positive step. However, these commenters stress that the protocol requirements need to complement the technology and not inhibit the benefits.

Response I-22-2: EPA acknowledges the commenters support for the development of Appendix K.

## ***22.1.2 Opposition to Requiring Use of Appendix K***

### ***22.1.2.1 General Dissent for the Use of Appendix K in Upstream Oil and Gas***

Comment: Numerous commenters (0462/0564/0764-Arkansas Independent Producers and Royalty Owners (AIPRO), 0579-Chevron, 0743-Western Energy Alliance (WEA), 0777-Ascent Resources, LLC (Ascent), 0793-Permian Basin Petroleum Association (PBPA), 0807-BP America, Inc. (BP), 0808-API, 0817-GPA Midstream Association (GPA), 0820-Pioneer, 0831-AXPC, 0834-A2C) objected to or expressed concern regarding the use of Appendix K in upstream or midstream oil and gas facilities. Commenters (0462-AIPRO, 0579-Chevron, 0777-Ascent, 0808-API, 0817-GPA, 0820-Pioneer, 0831-AXPC) stated that the monitoring requirements in Appendix K are more aligned with downstream facilities such as refining and processing plants. Commenters (0462/0764-AIPRO, 0607-Arktos Environmental LLC (AENV), 0743-WEA, 0777-Ascent, 0786-Enerplus Resources (USA) Corporation (Enerplus), 0793-PBPA, 0808-API, 0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK), 0817-GPA, 0820-Pioneer, 0831-AXPC, 0834-A2C, 0911-NDPC, 0938-Texas Oil & Gas Association (TXOGA)) stressed that the requirements are overly burdensome and not cost-effective for upstream facilities, including well pads, centralized production facilities, transmission compressor stations, or gathering and boosting stations. One commenter (0808-API) stated that Appendix K goes beyond the current NSPS OOOOa requirements concerning performance specifications, “operating envelope”, survey time, and records for leaking components and is impractical for operators to implement given the hundreds to thousands of well sites and compressor stations to monitor and the geographic dispersion of these facilities.

Some commenters (0564/0764-AIPRO, 0777-Ascent) state that the Appendix K protocol was principally designed to accommodate facility inspections in the downstream sector such as refining and processing plants. Commenters (0777-Ascent, 0808-API, 0817-GPA, 0834-A2C) noted that upstream facilities do not typically have dedicated staff or resources on-site to conduct monitoring surveys. Additionally, commenters (0786-Enerplus, 0808-API) stated that the Appendix K requirements do not account for the significantly different design, complexity, distribution, or operation of upstream production facilities; two commenters (0607-AENV, 0743-WEA) noted that the requirements do not accurately reflect the realities of conducting leak detection in rural, active oil field conditions and would dramatically reduce the ability and efficiency of operators to conduct leak inspections. One commenter (0808-API) stated that Appendix K would require several significant modifications to be effectively implemented across downstream oil and gas facilities, gas processing plants, or other process industries. Commenters (0786-Enerplus, 0793-PBPA, 0808-API, 0817-GPA, 0820-Pioneer, 0831-AXPC, 0834-A2C) specifically noted key differences between upstream and downstream facilities, including:

- (1) upstream and midstream facilities are smaller and less complex, with fewer regulated components (e.g., well sites contain tens to hundreds of components, and gathering and boosting stations have an average of 1,800 components - versus tens of thousands of components at a refinery; therefore the benefit of the economy of scale present at petroleum refineries is eliminated);
- (2) there are significantly more well sites and compressor stations;

(3) Upstream production operations are not steady-state process operations like a refinery, where the process flow is largely constant and consistent. Producers regularly have to adjust for variable conditions that can occur unpredictably from the formation or on the landscape, such as weather that can prevent or disrupt a planned monitoring activity;

(4) Because upstream facilities are located out on the natural landscape, rather than a large sited industrial location, they often have a different set of safety, environmental, or circumstantial issues to account for in the field, such as potential for H<sub>2</sub>S gas exposure, ecological considerations or even landowner limitations; and

(5) Downstream facilities have people onsite 24-hours a day, whereas most well sites, centralized production facilities, and compressor stations are unmanned sites in remote locations spread over large geographic areas requiring contractors to travel to perform OGI monitoring, often accompanied by operator personnel to provide access to the site. Unlike the larger sites, which have full-time personnel dedicated to one facility, most upstream companies assign one employee to multiple small sites, making on-site monitoring requirements particularly burdensome for small upstream producers.

Commenter (0817-GPA) specifically asserted that Appendix K is entirely unsuited for use at compressor stations. The commenter (0817-GPA) urged that if Appendix K is applied, EPA must revise elements of the protocol for midstream operations, notably: (1) excluding components with no detectable emissions; (2) excluding components below a certain VOC and methane threshold; (3) revising the senior OGI camera operator requirements; and (4) revising auditing requirements.

Another commenter (0462-AIPRO) stressed that Appendix K, as proposed, is not feasible for operators of upstream or midstream facilities to implement because the EPA is expanding the number of sites subject to OGI inspections while also making the inspection standards much more stringent. Commenters (0462-AIPRO, 0743-WEA, 0938-TXOGA) stated that the proposed standard would have a minimal impact on overall methane emissions and provide little environmental benefit, while substantially increasing operator costs. One commenter (0743-WEA) stated they support the continued use of OGI emissions detection in the production, gathering, boosting, transmission and storage segments, and its members are at the forefront of developing, implementing, and rigorously evaluating new technologies and approaches in the OGI space. However, as drafted, Appendix K outlines a set of additional recordkeeping, training, recording, and technical requirements that are largely impractical for use in upstream, midstream, transmission, and storage operations.

Several commenters (0793-PBPA, 0810-Petroleum Alliance-OK, 0814-Independent Petroleum Association of America (IPAA) et al., 0924-U.S. Small Business Administration (SBA), 0945/1373-JOFA Consulting (JOFA), 0959-Colt Midstream LLC (Colt)) expressed concern that the EPA has not considered the significant burden Appendix K will have on small businesses, small OGI operators, and particularly upstream companies. The commenters stated that they are concerned that this impact will disproportionately affect small businesses, which account for a large percentage of upstream operators. Commenters (0793-PBPA, 0959-Colt) noted that the field training, quality assurance and control, and the recordkeeping requirements create an

unnecessary burden on smaller to medium sized upstream and midstream oil and gas operators. For these requirements to have to be included with the facility records, the operator of the facility would potentially need to obtain these records from the contractor conducting the surveys for each survey performed at the facility. Further, one commenter (0793-PBPA) questioned if there will be adequate surveyors available to all operators, especially small oil and gas operators, when needed to meet the monitoring compliance requirements of NSPS OOOOa, NSPS OOOOb, and EG OOOOc. Another commenter (0810-Petroleum Alliance-OK) stated that EPA is making these survey compliance requirements too complicated and onerous for all operators, especially for small oil and gas operators that have marginal/low production wells. The commenter further stated the requirements will significantly extend survey timeframes beyond what is necessary to detect fugitive emissions, will likely require the use of contract surveyors, requires excessive electronic recordkeeping efforts, and increases costs excessively.

Response I-22-3: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>1</sup>

Comment: One commenter (0820-Pioneer) stated that based on their experience, a large horizontal tank battery takes 2.5 hours to survey. With the newly proposed requirements under Appendix K, they report it will take 5 hours and be done quarterly; and there are often safety concerns accessing the sites which could delay the process further. The commenter added that EPA is requiring surveys to be 60 days apart and this will be difficult to meet as each quarterly pass may take longer than expected and 60 days apart may not be feasible. The commenter stated that, if Appendix K remains in the rule, they recommend that EPA allow the surveys to be 30 days apart to allow more time to survey and help facilitate compliance with this new program.

Response I-22-4: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>2</sup>

Comment: Two commenters (0743-WEA, 0824-WDEQ) pointed out that there would be significant costs associated with meeting the requirements for the qualifications of the personnel operating OGI cameras in accordance with Appendix K. Operators will either have to undertake a costly training and certification process for their own staff or will have to hire qualified contractors to perform the work associated with the monitoring requirements. One commenter (0824-WDEQ) stated such costs are entirely prohibitive for many stripper well operators who would be subject to these requirements. As such, the commenter disagreed with EPA's assessment that it "no longer believes that production levels provide an appropriate threshold for

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<sup>1</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

<sup>2</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

any exemption from fugitive monitoring.” Small operators are already voicing concerns that they will have to shut down operations demonstrating that EPA’s assessment is inaccurate.

Response I-22-5: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>3</sup>

Comment: One commenter (0793-PBPA) stated that should EPA include Appendix K in the forthcoming regulatory text, they recommend the following modifications be incorporated at a minimum:

- *Low Production Well Sites:* There should not be a one-size-fits-all approach to leak detection for low producing wells, such as requiring OGI surveys regardless of facility production levels. EPA acknowledges in the November 2021 Proposal that there is wide variability among low producing well sites with respect to methane emissions. Thus, EPA should not be overly prescriptive and should accommodate use of alternate technologies or even those that are yet to be developed and that may be economic for low production well sites as opposed to mandated OGI surveys that are likely to cause severe economic harm to the small business owners who primarily own these well sites.
- *Survey Frequency:* EPA’s cost justification is largely based on stale assumptions from old rulemakings and sources. EPA should collect updated information to create an adequate record that supports its proposal, as EPA has done for prior rulemakings. For example, in a 2020 rulemaking, EPA appropriately recognized varying emissions reductions based on type of site (low production site, gas well site, and oil well site) and monitoring frequency. But EPA didn’t account for those differences in its NSPS OOOOb/EG OOOOc proposal. EPA should start with LDAR applicability criteria from prior NSPS OOOO and NSPS OOOOa rulemakings and then inventory the types of facilities, well sites, and throughputs in order to craft a rule that avoids a “one-size-fits-all” approach applicable to millions of sites.

Response I-22-6: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>4</sup>

#### 22.1.2.2 Use of NSPS OOOOa Procedures in NSPS OOOOb and EG OOOOc

Comment: Several commenters (0462/0564/0764-AIPRO, 0607-AENV, 0743-WEA, 0802-Kraken Oil & Gas LLC (Kraken), 0807-BP, 0808-API, 0810-Petroleum Alliance-OK, 0831-AXPC, 0834-A2C, 0911-NDPC, 0938-TXOGA) stated that NSPS OOOOa OGI surveys are effective and sufficient to reduce methane emissions and recommended that EPA codify NSPS

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<sup>3</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

<sup>4</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

OOOOa OGI procedures (with updates to streamline the method) for NSPS OOOOb and EG OOOOc OGI requirements for upstream facilities. The commenters noted that those rules have been implemented since 2015, and operators have designed processes and procedures to comply with those requirements over the last 7 years. The commenters noted that those requirements establish reasonable and appropriate OGI monitoring plan requirements that are likewise appropriate and reasonable to include in NSPS OOOOb and EG OOOOc. They added that those requirements have been functioning as a means of mitigating emissions in upstream operations and would be equally adequate for setting forth OGI requirements under a future NSPS OOOOb or EG OOOOc proposal.

One commenter (0808-API) stated that with respect to the proposal requirements for new (NSPS OOOOb) and existing (EG OOOOc) sources, the commenter generally supports, with recommended changes to Appendix K and its application, the provisions for fugitive emissions monitoring at well sites, compressor stations, and gas processing plants and remarked on the differences between the protocols and the types of sources that Appendix K and the NSPS OOOOa procedures are intended to address. The commenter asserted that EPA has not demonstrated that the more stringent requirements of Appendix K are more effective at detecting leaks at well sites, centralized production facilities, and compressor stations, whereas NSPS OOOOa camera specifications have been demonstrated as feasible through EPA testing and in the field. A different commenter (0579-Chevron) suggested that EPA reevaluate Appendix K for use in upstream facilities and craft applicable rules accordingly.

Response I-22-7: In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>5</sup>

#### 22.1.2.3 Limit Use of Appendix K

A commenter (0808-API) recommended EPA limit Appendix K to refineries, gas plants, and similar larger process operations in other industries. The commenter stated that while the proposed Appendix K OGI protocol is not appropriate for use in the production and transmission sectors, where OGI monitoring specifications should continue to be based on NSPS OOOOa requirements, with the commenter's recommended modifications to Appendix K, the commenter generally supports its application for gas processing plants, petroleum refineries, and similar facilities. The commenter also proposed that EPA could strengthen the standards in OOOOa for using OGI in the production and transmission categories without applying Appendix K. Another commenter (0834-A2C) suggested that Appendix K should only be an optional alternative to EPA Method 21 for downstream natural gas processing plants and petroleum refineries in the oil and natural gas source category. The commenter stated that they wholly support the use of OGI as an alternative to leak detection using EPA Method 21 and that with appropriate applicability and adjustments as detailed by other commenters. The commenter also supported establishing Appendix K as a performance specification for OGI at complex process facilities. Yet another

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<sup>5</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

commenter (0938-TXOGA) stated that Appendix K was developed and designed for downstream facilities (e.g., natural gas processing plants, natural gas liquids fractionation facilities, petroleum refineries). As the commenter understands it, the concept is that Appendix K is designed to provide a protocol for facilities to conduct OGI monitoring on difficult-to-monitor components at plants (e.g., elevated fugitive components), in combination with the current physical monitoring (e.g., EPA Method 21).

Several commenters (0607-AENV, 0743-WEA, 0748-American Fuel & Petrochemical Manufacturers (AFPM), 0777-Ascent, 0808-API) supported EPA in the development of Appendix K to establish appropriate protocols for complex downstream petroleum refineries with dedicated on-site staff to conduct fugitive monitoring surveys and at natural gas plants. However, these commenters asserted that significant modifications to Appendix K are necessary before it is implemented. The commenters recommended specific changes to the November 2021 Proposal (see specific recommended changes in the other sections of this chapter) to address their concerns that the proposed requirements would: 1) result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators; 2) create training and quality assurance/quality control (QA/QC) requirements that are overly burdensome without leading to more effective leak detection; and 3) cause the ownership of various requirements, and particularly the recordkeeping requirements to be unclear and unnecessarily burdensome. The commenters also recommend that EPA include some clarifications and efficiency changes to Appendix K.

Response I-22-8: See responses to specific comments raised on Appendix K throughout the rest of this chapter.

In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>6</sup>

#### 22.1.2.4 Appendix K Could Hinder Future Technology

Comment: One commenter (0782-Berkshire Hathaway Energy Company (BHE)) cautioned that the proposed Appendix K has the potential to negate future progress by introducing a substantial hindrance to the use of OGI technology; the commenter recommended retaining the standard LDAR provisions and not adding further requirements without first supporting/rationalizing the need for additional rigor, and suggested that EPA launch “a more inclusive and deliberate process to develop an OGI method that more thoroughly engages stakeholders.” Another commenter (0807-BP) expressed concern that emphasis on OGI could have the unintended consequence of mis-prioritizing LDAR resources. The commenter pointed out that OGI, unless supplemented by other higher frequency technologies, can leave the majority of calendar days unmonitored.

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<sup>6</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).



One commenter (1291-INGAA) stated issues with Appendix K go beyond stifling OGI. The commenter contended that the stringency and burdensome nature of Appendix K has implications for the adoption and implementation of other imaging or infrared-based technologies that are integral to the proposed rule (e.g., any new technologies such as remote or fence-line monitoring should have similar methods). The commenter noted that methods such as this would preclude technology deployment and is in direct conflict with EPA's desires to expand technologies available to both operators and communities. If EPA wants pathways to new technology that will offer more continuous monitoring or more transparency to communities, the commenter asserted that Appendix K is not the way to achieve those goals. Because these types of programs require some type of standardization, the commenter believed that Appendix K will preclude progress on these important issues. According to the commenter, it is incumbent on EPA to prepare methods that are simple, streamlined, easily replicated, and developed for all stakeholders.

One commenter (0782-BHE) observed that a highly prescriptive protocol could limit the ability of new lower cost and lower fidelity technologies. Further, as written, Appendix K may limit competition by reinforcing current IR monopolies, maintaining high camera prices, and working against the Agency's stated objective to identify and reduce meaningful leak emissions. This commenter provided an example of a lower cost long wave infrared uncooled microbolometer which can detect methane leaks and may be appropriately suited to identifying consequential leaks. However, this camera technology is currently incapable of visualizing propane at the concentration and mass rate specified in 40 CFR 60.5397a(c)(7)(i)(B). The commenter also recommended retaining EPA Method 21 as an acceptable method for test method alternatives; the commenters stated that due to the costs and limitations of OGI operator availability, alternative leak survey methods would likely be necessary to provide flexibility. The commenter posited that Appendix K holds operators to a much different strata of performance criteria, and that resource limitations may inadvertently force operators to "backslide" to EPA Method 21.

Response I-22-9: EPA disagrees that Appendix K will negate progress on future technologies and notes that there are many advanced technologies for leak detection currently being tested and implemented in different sectors. EPA has provided a pathway for use of advanced technologies in NSPS OOOOb and EG OOOOc. See Volume II, Chapter 5, and discussion in section X.B of the preamble to the final rule for information on advanced technologies. EPA has also retained the use of EPA Method 21 as an alternative to OGI for conducting monitoring of fugitive emissions and leaks.

EPA made substantial edits to Appendix K in response to comments on the November 2021 Proposal. See discussion in section VI of the December 2022 Supplemental Proposal.<sup>7</sup> In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>8</sup>

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<sup>7</sup> 87 FR 74837-74842 (December 6, 2022).

<sup>8</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

Comment: Many commenters (0458-MDE, 0558-Center for Climate and Energy Solutions (C2ES), 0759/0780-LongPath Technologies, Inc. (LongPath) et al., 0782-BHE, 0814-IPAA, 0844-Environmental Defense Fund (EDF) et al., 0935-Colorado Oil and Gas Association (COGA), 0954-Teledyne FLIR, LLC (FLIR), 1391-Interstate Natural Gas Association of America (INGAA)) expressed support for the inclusion and development of a wide variety of technologies and platforms for leak detection endeavors. Some commenters (0558-C2ES, 0954-FLIR) specifically referenced quantitative OGI while several others (0590-Honeywell, 0756-Baker Hughes, 0759/0780-LongPath, 0782-BHE, 0791-Airdar, Inc., 0808-API, 0844-EDF, 0944-Kuva Systems) discussed the various platforms that are applicable and currently in use at some facilities (most notably drones, sensor networks, and continuous monitoring). There was strong support from many commenters (0756-Baker Hughes, 0808-API, 0831-AXPC, 0911-NDPC, 1391-INGAA) encouraging EPA to change the definition for OGI to include drone-based and fixed, continuous applications at a minimum in order to allow for technology innovations and application flexibility. Other commenters (0760-Airdar et al., 0762-CleanConnect.AI et al., 0954-FLIR) proposed that EPA develop separate alternative work practices for the various alternative technologies and platforms.

Commenter (0782-BHE) identified seven categories of OGI technology for which EPA should consider broadening the Appendix K scope or developing new protocols:

- Portable handheld OGI (Appendix K);
- Fixed OGI;
- Methane sensors;
- Open path fence line air monitoring;
- Drone imaging;
- Fixed wing or helicopter remote surveillance; and
- Satellite imaging.

This inclusive technology-flexible approach was echoed by others as noted above. In cases where the leak source is intermittent, one commenter (0780-LongPath) recommended that another form of OGI (such as continuous monitors) be allowed for follow-up surveys/monitoring.

Response I-22-10: EPA removed the terminology “hand-held” from Appendix K in response to comments in the December 2022 Supplemental Proposal. We recognize that it is potentially possible to follow the requirements outlined in Appendix K while using an OGI camera mounted on a drone, and we did not intend to limit technology development. The use of OGI in other configurations would be dependent on the ability of the camera operator to follow the requirements outlined in Appendix K. For example, it is unlikely that a fixed-mount camera would be able to view components from multiple angles or that the operator of such a camera would be able to always adjust the view to account for interferences. Our intent was not to cover these types of applications in Appendix K, although EPA may update Appendix K or develop new protocols that do cover these applications in a future rulemaking.

EPA has also provided a pathway for use of advanced technologies in NSPS OOOOb and EG OOOOc. See Volume II, Chapter 5, and discussion in section X.B of the preamble to the final rule for information on advanced technologies.

#### 22.1.2.5 General Dissent

Comment: Commenters (0607-AENV, 0718-Tora Consulting, LLC (Tora), 0749-PAW, 0777-Ascent, 0793-PBPA, 0794-MHAN, 0816-Montrose) asserted that the onerous and overly prescriptive requirements proposed in the November 2021 Proposal of Appendix K may negate efficiencies gained from the use of OGI cameras (over other fugitive survey methods such as EPA Method 21) and would not always improve emissions reduction efficacy. Commenters (0749-PAW, 0938-TXOGA) contend that the regulatory constraints applied through Appendix K will significantly reduce, if not eliminate altogether, any advantages in efficiency or accuracy that OGI monitoring may provide over EPA Method 21. Another commenter (0911-NDPC) supported creating a protocol for OGI camera use and only referencing the protocol in the rule text but noted that there is little in Appendix K that they agree is appropriate.

Commenters (0749-PAW, 1291-INGAA) stated that the proposed requirements in Appendix K do not add any environmental benefits and are inordinately excessive and impractical and would preclude or severely hinder the ability of operators to conduct OGI leak surveys. Commenters (0607-AENV, 0718-Tora, 0938-TXOGA) noted that there would be a significant administrative burden to camera operators added by Appendix K that would result in activities which are not directly applied to leak identification and take time away from actual monitoring activity. The commenters stated that Appendix K negates the fundamental benefit of an OGI-LDAR program; specifically, the ability to safely and efficiently detect large leaks, which account for a majority of fugitive emissions (on a mass basis) at a facility. They asserted that excessive time spent on administrative activities does not support emissions reduction.

Commenters (0607-AENV, 0718-Tora) suggested that EPA should be improving the flexibility of OGI monitoring; for example, removing the annual EPA Method 21 requirement from the alternative work practice (AWP) in the part 60 General Provisions. Instead, the commenters stated that EPA is proposing to implement OGI monitoring, training, and auditing requirements that would make implementation nearly impossible. The commenters further stated that industry has adapted to the OGI provisions in 40 CFR 60.18 and 60.5397a. They suggested that any new method should be limited to those procedures which are already used in practice. The commenters added that Appendix K, as proposed in the November 2021 Proposal, would serve to discourage, not support, the use of OGI as a leak detection method.

According to the commenters (0607-AENV, 0718-Tora, 1291-INGAA), in no case should an OGI method be more stringent or burdensome than EPA Method 21, which has never contained the type of overreaching training, auditing, and monitoring requirements as are found in the proposed version of Appendix K, which could preclude or severely hinder the ability of operators to conduct OGI leak surveys. One commenter (1291-INGAA) stated that, as written, the Appendix K requirements will result in far less use of OGI technology for leak surveys, with operators being forced to opt for EPA Method 21 surveys instead. The commenter noted examples of issues with Appendix K related to training and operator certification hours, training cost (exceeding \$200,000), availability of experts and lack of qualification for existing staff, increase of survey time (by four-fold), and extensive recordkeeping, confusion regarding ownership of equipment requirements, inconsistencies in detection limits, rest break requirements, and weather data requirements.

One commenter (0820-Pioneer) questioned the reason for the extensive changes included in the Appendix K protocol. The commenter contended that the added burden, paperwork, and more stringent timelines are a product of EPA's skepticism and implication that operators are acting in bad faith. The commenter further stated that with the doubling of the survey frequency, they will need more thermographers. At the same time, the commenter contended, Appendix K imposes an additional burden on the thermographers time. Training, QA/QC, auditing, dwell time requirements, lengthy voluminous video clips, and recordkeeping requirements are unnecessary, unreasonably burdensome, and technologically infeasible. The combined requirements reduce the hours a camera operator can spend monitoring.

Another commenter (0817-GPA) expressed that Appendix K would impose a significant burden on the current use of OGI at compressor stations, due to its rigor. The commenter claimed that EPA provides no explanation as to why the current OGI practices require “such a significant overhaul.” The commenter considered the following to be “unwarranted burdens”: (1) the development of the operating envelope, (2) the requirement to take breaks to avoid fatigue at such a relatively small facilities, (3) the rigorous OGI camera operator training, and (4) the daily and quarterly audits. The commenter stated that these burdens eliminate much of the advantage that OGI provided over EPA Method 21. The commenter urged that EPA must definitively account for the additional costs and time that would now be required.

Response I-22-11: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in section VI of the December 2022 Supplemental Proposal for information related to the changes made to Appendix K.<sup>9</sup>

Additionally, in response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>10</sup>

See responses to specific comments raised on Appendix K throughout the rest of this chapter.

## **22.2 Scope and Applicability of Appendix K**

Comment: Some commenters (0604-Providence Photonics, LLC (Providence), 0748-AFPM, 0808-API, 0831-AXPC) urged that Appendix K should not be limited to the oil and gas sectors. Commenters (0604-Providence, 0748-AFPM, 0808-API, 0831-AXPC) stated that the protocol is technically applicable to other industries, such as organic chemical manufacturing plants and ethylene production units. Commenters (0604-Providence, 0748-AFPM, 0808-API) urged that a narrow applicability to the oil and gas sector would not serve any purpose, but would limit the beneficial applications of Appendix K. One commenter (0808-API) stated that because the proposed Appendix K clearly identifies in sections 6.1.1 and 6.1.2 that it applies where a particular OGI camera is sensitive enough to find leaks and rulemaking or Administrator approval would be needed to allow use of OGI for a process not covered by the current rulemaking, it would be counterproductive to limit Appendix K only to oil and gas source

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<sup>9</sup> 87 FR 74837-74842 (December 6, 2022).

<sup>10</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

categories. Commenters (0604-Providence, 0808-API, 0831-AXPC) recommended that EPA remove the explicit exclusion for “chemical plants or other facility types outside of the oil and gas upstream and downstream sectors.”

Response I-22-12: EPA made substantial edits to Appendix K and the applicability of Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in section VI.B.1. of the December 2022 Supplemental Proposal related to the scope of Appendix K.<sup>11</sup>

Comment: A commenter (0604-Providence) remarked that if there are specific provisions in Appendix K that are meant to apply specifically to the oil and gas sectors, the specificity should be clarified, and the technical criteria or specifications should be added to allow for broad applications. Another commenter (0750-Flogistix) critiqued that Appendix K already appears to be written for broader application than the oil and gas source category and suggested that future amendments to Appendix K intended for other sectors may have unintended consequences on upstream oil and gas sources. Yet another commenter (0911-NDPC) also encouraged EPA to work with OGI equipment manufacturers to develop section 1.0 of Appendix K to clarify the scope.

Response I-22-13: EPA acknowledges that Appendix K is written for broad applicability, as discussed in the November 2021 Proposal.<sup>12</sup> EPA also acknowledges that future changes to Appendix K will affect any sector that is required to use Appendix K, similar to how changes within test methods affect different sectors that are required to use those methods. Any future change to Appendix K will be subject to notice and comment rulemaking prior to implementing the change.

In response to comments received on the November 2021 Proposal, EPA updated the scope and applicability of Appendix K. For details, please see discussion in section VI.B.1. of the December 2022 Supplemental Proposal.<sup>13</sup>

Comment: Some commenters (0782-BHE, 0808-API) expressed that publishing an NSPS-specific OGI protocol would likely introduce a number of limitations or complications regarding applicability for other sectors or may preclude opportunities to supplant other EPA Method 21 applications. One commenter (0808-API) urged that EPA should also be specific in the referencing subpart as to the process chemistry that must be present to use OGI and Appendix K, or through the permit or Administrator review where it is requested, to be used for sources not covered by a referencing subpart. The commenter reiterated that the purpose of part 60 appendices is to provide generic methodologies that do not have to be amended each time they are referenced. Other commenters (0782-BHE, 1458-Innovative Environmental Solutions, Incorporated (IES)) specifically requested that OGI be broadly applicable and not tied to development of a specific NSPS; these commenters supported the development of an Air Emission Measurement Center stand-alone test method under 40 CFR part 60, Appendix A instead.

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<sup>11</sup> See 87 FR 74837 (December 6, 2022).

<sup>12</sup> See 86 FR 63172 (November 15, 2021).

<sup>13</sup> See 87 FR 74837 (December 6, 2022).

Response I-22-14: The proposed Appendix K was not intended to apply to one specific NSPS. As noted in the November 2021 Proposal, Appendix K is written for broad applicability.<sup>14</sup> It is not uncommon for test methods to also be published with a specific rulemaking, even though they may be used in other sectors in the future. For example, EPA Method 325A/B was originally published in the Refinery MACT RTR rulemaking, but this method was also proposed for use in chemical sector rules.<sup>15</sup> Appendix K is being treated in the same manner, in that it is being finalized in the first sector that is using it but may be applied to other sectors in future rulemakings.

However, that EPA may at some point in the future reference Appendix K in other subparts does not mean that Appendix K is immediately available to supplant EPA Method 21 applications in other subparts. Appendix K does not apply to any other sectors until it is referenced by a subpart through rulemaking that considers the cost of implementation and whether the incorporation of Appendix K, with or without supplemental requirements or leak detection alternatives, achieves the applicable standard for a specific industry sector. EPA does not anticipate that it will be necessary to update Appendix K each time that it is referenced in a new subpart but may do so if new information indicates that an update is necessary.

Comment: Some commenters (0750-Flogistix, 0756-Baker Hughes, 0954-FLIR) remarked that the use of the OGI camera is limited to hand-held surveys. One commenter (0756-Baker Hughes) supported the alternative fugitive emissions monitoring program with the caveat that EPA should revise Appendix K to modify the OGI equipment definition beyond hand-held applications and to include other platforms, such as drone-based OGI. Another commenter (0954-FLIR) requested clarity on what means of OGI technology outside of hand-held, if any, are applicable, and recommend non-handheld uses of the technology be separated from Appendix K.

Response I-22-15: EPA removed the terminology “hand-held” from Appendix K in response to comments in the December 2022 Supplemental Proposal. We recognize that it is potentially possible to follow the requirements outlined in Appendix K while using an OGI camera mounted on a drone, and we did not intend to limit technology development. The use of OGI in other configurations would be dependent on the ability of the camera operator to follow the requirements outlined in Appendix K. For example, it is unlikely that a fixed-mount camera would be able to view components from multiple angles or that the operator of such a camera would be able to always adjust the view to account for interferences. Our intent was not to cover these types of applications in Appendix K at this time.

Comment: One commenter (0808-API) stated that the applicability of Appendix K belongs in a referencing subpart, not in the protocol (section 1.3). The commenter also stated that the applicability does not reflect that the protocol addresses equipment leaks. The commenter recommended that section 1.3 be revised to “This protocol is applicable to equipment leak components at facilities when referenced by an applicable subpart.”

Response I-22-16: EPA made substantial edits to Appendix K and the applicability of Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in

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<sup>14</sup> See 86 FR 63172 (November 15, 2021).

<sup>15</sup> See 80 FR 75178 for the Refinery MACT RTR rulemaking. The use of Method 325A/B was proposed in technology reviews of the Hazardous Organic NESHA and Polymers and Resins I. See 88 FR 25080.

section VI.B.1. of the December 2022 Supplemental Proposal related to the applicability of Appendix K.<sup>16</sup>

## **22.3 Definitions and Terminology**

### ***22.3.1 Appendix K's Title***

Comment: Two commenters (0607-AENV, 0718-Tora) urged EPA to replace the term “Determination” in the title of Appendix K to “Identification” or “Detection”, asserting that the purpose of the protocol is to detect or identify leaks, not determine leaks.

Response I-22-17: EPA disagrees with the commenter. The purpose of Appendix K is to determine that a leak exists, which we recognize is the same as identifying and detecting leaks. We chose to use the word determination because it is the same word used in the title of EPA Method 21, which is similar in purpose to Appendix K.

### ***22.3.2 Regulated Components***

Comment: One commenter (0808-API) recommended that the term “regulated components” in Appendix K be changed to “equipment leak components regulated by the referencing subpart or permit.” The commenter (0808-API) stated that there are components regulated under other rules (e.g., a chemical process unit located within a refinery) or by non-equipment leak portions of the referencing rule or permit (e.g., process vents) that might be within an OGI camera’s operating envelope.

Response I-22-18: EPA agrees with the commenter. We have changed terminology from “regulated components” to “components regulated by the referencing subpart.”

### ***22.3.3 Fugitive Emission or Leak Definition***

Comment: One commenter (0808-API) questioned the definition of “fugitive emission or leak”, proposed as “any emissions observed using OGI.” The commenter stressed that the definition can only address emissions from equipment components identified in the referencing subpart or permit as being subject to OGI monitoring, as these are the only emission sources that were considered in the referencing subpart rulemaking or permitting process and are the only components that the referencing subpart or permit monitoring and repair provisions address. The commenter recommended the following definition: “Fugitive emission or leak means any emissions observed using optical gas imaging from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).”

Response I-22-19: EPA has updated the definition of fugitive emission or leak to mean “any emissions observed using OGI from components regulated by the referencing subpart.”

### ***22.3.4 Response Factor Definition***

Comment: Numerous commenters had questions related to the definition of response factor in section 3.0 of Appendix K. One commenter (0561-TRICORD Consulting, LLC (TRICORD))

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<sup>16</sup> See 87 FR 74837 (December 6, 2022).

asked for clarity on the meaning of 10,000 parts per million-meter (ppm-m) basis. The commenter (0561-TRICORD) further stated that it appears that response factor determinations in the references are from a laboratory setting and recommended a combined EPA/industry group funded study to develop response factors for OGI. Another commenter (0782-BHE) noted that the current definition omits that the reference compound is propane and also ignores the fact that an optical path length-concentration measurement in ppm-m is typically associated with gas cell measurements specific to temperature differential and other optical window variables. The commenter requested the elimination of the performance measure requirement to estimate a ppm-m performance using ideal laboratory test conditions because it may result in uncertainty and the need for gas cell measurements to achieve this proposed performance specification has not been adequately established. The commenter provided an alternative: EPA should specify a signal to noise (S/N) ratio for a camera for a certain gas at a certain concentration under given radiant conditions. This analysis would be completed by the original equipment manufacturer (OEM) and specified in section 6.0 of Appendix K. The commenter provided an example specification: the camera shall produce a S/N ratio of 1 or greater when viewing a pure gas mixed homogeneously in nitrogen at atmospheric pressure while viewing a highly emissive, >96%, blackbody at 27°C when under laboratory conditions whose average ambient temperature is 22°C. Both the temperature difference ( $\Delta T$ ) and the absolute temperature are necessary to make this determination.

Response I-22-20: EPA revised the definition of response factor in the December 2022 Supplemental Proposal and added Annex 1 to Appendix K that details a procedure for determining the response factors for OGI Cameras. EPA notes that response factors vary between camera models, and as such, one study would not be enough to determine response factors for all current and future OGI camera models.

The commenter is correct that an S/N metric could be a potential measure of camera performance. However, with a midwave infrared (MWIR) cooled camera, it is anticipated that an extremely large S/N is required, and EPA does not currently have enough empirical data on what S/N range of the detector radiance output would be appropriate. As such we cannot integrate this approach at this time. If EPA conducts additional testing or receives additional information on this type of approach, such an approach could be incorporated into Appendix K in a future rulemaking.

Comment: One commenter (0719-Opgal Optronic Industries, Ltd. (Opgal)) stated that the current response factor definition proves that the response factor is a function (not a factor, Zeng et al., 2017) of concentration length and response sensitivity of a reference gas (i.e., propane in this protocol). The commenter stated that response factor criteria is manufacturer specific and therefore should not appear in this protocol. Another commenter (0604-Providence) agreed that the response factor is specific to a given OGI camera model and can vary between different camera models. The commenter recommended explicitly stating this in the definition to avoid improper use of response factors by operators who may not be aware that response factors are specific to OGI camera models.

Response I-22-21: The definition of response factor was modified in response to comments. Specifically, EPA has indicated that response factors are camera model specific. See discussion



in section VI.B.5 of the December 2022 Supplemental Proposal for more information related to response factors.<sup>17</sup>

Comment: Two commenters (0808-API, 0831-AXPC) raised issues with the second line of the response factor definition, which limits the response factors to those obtained from peer reviewed articles or developed according to procedures approved by the Administrator. The commenters explained the two main issues with this limitation as follows:

- The first issue is that there may be different response factors for different OGI cameras as technology changes and new response factors will be needed as additional applications of OGI are made. Such commercial information is not amenable to publication in peer reviewed articles, nor could such response factors be published in a timely manner. Thus, if anything is to be peer reviewed it must be the methodology used to develop the response factors. Given the specifics in the first sentence (a path-length of 10,000 ppm-m) and the specification in section 6.1.1 of propane as the reference compound, it seems unnecessary to require any review of the response factors themselves.
- Secondly, hundreds of response factors have been developed by camera manufacturers for current cameras. One commenter (0808-API) expressed concerns that those response factors, which are currently in widespread use, might not meet the criteria in the proposed definition. While these factors may have been peer reviewed, they were not necessarily “obtained from peer reviewed articles.” The commenter further pointed to the uncertainty involved in the procedures the Administrator might require and whether currently used factors will be found to be consistent with that yet undefined procedure.

The commenters believed that the criteria in the first sentence of the proposed definition and in section 6.1.1 of the proposed Appendix K are adequate to assure valid response factors and recommended deleting the second sentence of the definition. The commenters further recommended that if the Agency believes the response factor limitation is needed, it should focus the limitation on the methodology for developing response factors, propose the methodology they plan to require when the final Appendix K language is proposed, provide for automatic approval after 90 days of any response factor or response factor methodology submitted to the Administrator if no action is taken within that time, and grandfather response factors developed prior to the proposal of the Administrator’s methodology

Response I-22-22: In response to comments on the November 2021 proposed rule, as part of the December 2022 Supplement Proposal, EPA developed Annex 1 to Appendix K, which is a methodology for the development of response factors for OGI cameras. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal for more information related to response factors.<sup>18</sup>

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<sup>17</sup> 87 FR 74839 (December 6, 2022).

<sup>18</sup> 87 FR 74839 (December 6, 2022).

### ***22.3.5 Senior OGI Camera Operator Definition***

Comment: Several commenters raised concerns over various aspects of the definition of a senior OGI camera operator. One commenter (0561-TRICORD) considered the requirement for a senior OGI camera operator to have surveyed 500 sites to be unrealistic and burdensome. Other commenters (0607-AENV, 0718-Tora) agreed with this perspective and considered the site requirement to be arbitrary. Similarly, another commenter (0954-FLIR) argued that there are numerous severe challenges with the current definition of a senior OGI camera operator. Yet another commenter (0782-BHE) provided further agreement with this perspective and noted that the basis for requiring a senior OGI camera operator to complete a minimum of 500 site surveys is not supported or substantiated and is excessive. The commenter further argued that this criterion focuses less on demonstratable experience of an OGI camera operator and focuses more on the estimated number of surveys completed. Commenters (0814-IPAA, 0945/1373-JOFA) stated that EPA “needs to define a senior level operator more explicitly including qualifications and exemptions.”

A commenter (0916-Alaska Oil and Gas Association (AOGA)) focused on the “minimum of 500 sites, and 20 sites in the past 12 months” aspect of the senior OGI camera operator definition and stated that there are no camera operators in the state of Alaska who would meet this qualification threshold. Another commenter (1391-INGAA) concurred that the current definition results in very few people being qualified for this designation; including personnel that have consistently conducted quarterly LDAR surveys for three years. Another commenter (0750-Flogistix) finds the senior OGI camera operator definition to be restrictive, while a different commenter (0911-NDPC) argued that the definition does not consider the years of experience of a camera operator and their understanding of equipment or processes. One commenter (0817-GPA) believed that there is no justification for the 500-survey requirement and considered it to be excessive, especially for midstream operations. The commenter further justified that for midstream facility operators, which operate far fewer facilities that are frequently far apart from each other, it would likely take many years for in-house personnel to qualify as a senior OGI camera operator. This effectively prohibits the use of company personnel to conduct surveys for the foreseeable future, imposing a significant additional cost without a demonstrated benefit. Another commenter (0743-WEA) agreed with the perspective presented by the commenters above and stated that the requirement to complete 500 site surveys and 20 within the past year would be a very difficult standard to meet for operators. The commenter further stated that many operators do not have 500 sites to be surveyed within their organization.

Two commenters (0607-AENV, 0718-Tora) stated that qualification as a senior OGI camera operator could be based on multiple indices of experience (hours of OGI camera operation, number of OGI surveys, number of sites surveyed, etc.) not just the number of sites that the operator has surveyed. The commenters further argued that EPA should not dictate the minimum number of sites, hours, or surveys necessary to be a senior OGI camera operator but allow the operators to have discretion to qualify personnel as senior OGI camera operators. Another commenter (0954-FLIR) recommended that the qualification for a senior OGI camera operator be changed from number of sites to either the number of hours spent conducting OGI surveys, the number of surveys, or the number of components inspected. A third commenter (0782-BHE) agreed with the recommendation of changing the site survey criteria to hours of OGI operation and further recommended 500 operating hours as a reasonable requirement for skilled OGI

operators. A fourth commenter (0816-Montrose) agreed with the recommendation of changing number of surveys to hours of operation and further commented that their research indicates that 160 hours of training is sufficient as a requirement to be classified as a skilled OGI operator. Another commenter (0911-NDPC) provided further agreement to the requirement change from surveys to hours and recommended that the minimum level be changed to 40 hours of OGI operation per year including a minimum of 24 hours of in-field training.

One commenter (0561-TRICORD) suggested the following modified definition for a senior OGI camera operator *“A Senior OGI Operator is a camera operator with more than two years’ experience operating an OGI camera or an operator with more than one year experience who has also completed, developed or provided classroom camera operator training”*. A different commenter (0808-API) proposed a different revised definition for a senior OGI camera operator: *“A senior OGI camera operator is an OGI camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or 2) is a certified thermographer. Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator.”*

The commenter (0808-API) further explained that the removal of career experience requirements is critical since they believe that this does not significantly add to the operator’s ability to train or audit other operators. The commenter believes that recent experience with current equipment and requirements at locations of the type currently being monitored is more critical to training and auditing others and hence recommends the 12-month criterion in the senior operator definition. The commenter goes on to provide an extensive description of how career experience is not of great importance by pointing to the results of operator experience testing reported in the Appendix K Technical Support Document (TSD). Another commenter (0831-AXPC) agreed with this commenter and suggested using 20 hours of recent monitoring as a requirement instead of number of sites. The commenter also agreed on the 12-month monitoring criterion recommendation.

One commenter (0817-GPA) suggested changing the senior operator experience requirement to 200 regulatory surveys rather than the currently stated 500 surveys. The commenter also recommended considering annual training as substitute for a certain number of surveys, referencing the EPA Method 9 smoke school methodology. Another commenter (0743-WEA) suggested that EPA require a senior operator be a certified thermographer, and field training for OGI camera operators consist of an hours-based training requirement. The commenter further recommended that as an alternative to Appendix K as currently drafted, EPA should require that operators establish a training and verification program but allow flexibility for operators to determine the requirements of that program based on the complexity and scope of their operations.

Response I-22-23: In response to comments on the November 2021 Proposal, the definition of Senior OGI camera operator was modified. See discussion in section VI.B.3 of the December 2022 Supplemental Proposal for more information.<sup>19</sup>

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<sup>19</sup> See 87 FR 74838-47839 (December 6, 2022).

Comment: Numerous commenters sought clarification on the use of “Site/Sites” in the definition of a senior OGI camera operator. One commenter (0561-TRICORD) questioned whether a refinery or a single process unit would be considered as one site and stated that 500 sites would only be attainable at upstream facilities. Another commenter (0743-WEA) provided a similar argument, questioning whether a wellhead-only site survey would be equivalent to a large refinery. Other commenters (0607-AENV, 0718-Tora) agreed with this point of view and stated that since the term “site” is not defined and with no other qualification criteria included, Appendix K currently considers the experience gained from monitoring a single well site equivalent to the experience gained from monitoring a refinery. A different commenter (0719-Opgal) questioned whether 500 days at a site is only considered as one site. Yet another commenter (0954-FLIR) argued that the current definition of “site” is very ambiguous especially since the applicability is implied for both upstream and downstream sectors which vary greatly, both from each other and within each other. The commenter further stated that there are several OGI camera users with over 15 years of experience, but just at one site, which would not fulfill the 500-site requirement.

Other commenters (0816-Montrose, 0831-AXPC) noted that a site-based qualification standard is arbitrary since sites vary significantly by size, complexity and number of components. Commenters (0808-API, 0831-AXPC) found “site” to be a very imprecise term for the senior OGI camera operator definition. One commenter (0599-Marcellus Shale Coalition (MSC)) stated that it appears that the intent is for 500 different surveys, as stated at EPA's Optical Gas Imaging Stakeholder Workshop, November 9-10, 2020. The commenter suggested rewording the definition to agree with the findings of that presentation such that all references to sites be changed to survey.

Response I-22-24: In response to comments on the November 2021 Proposal, EPA removed the requirements for number of sites surveyed in the definition of Senior OGI camera operator. See discussion in section VI.B.3 of the December 2022 Supplemental Proposal for more information.<sup>20</sup>

Comment: One commenter (1425-Eclipse Environmental Services, LLC) questioned whether they needed to submit evidence of 500 inspections and 20 in the last 12 months to a point of contact in EPA.

Response I-22-25: In order to become a senior OGI camera operator, the operator does not need to submit a certification to EPA. The operator must maintain records demonstrating compliance with the experience and training requirements outlined in Appendix K. These documents must be made available for review upon request.

### ***22.3.6 Ambient Air Temperature Definition***

Comment: A commenter (0954-FLIR) recommended modifying the definition of ambient air temperature in section 3.0 of Appendix K to be more specific about the location. The commenter recommended that the current definition be modified to “the air temperature in the general

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<sup>20</sup> See 87 FR 74838-47839 (December 6, 2022).

location where the leak is located by the OGI survey,” as there could be varying ambient air conditions at the site location.

Response I-22-26: EPA has updated the definition of ambient air temperature in section 3.0 of Appendix K to mean “the air temperature in the general location of the component being surveyed.”

#### ***22.3.7 Delta Temperature (delta-T) Definition***

Comment: A commenter (0561-TRICORD) contended that the assumption that emitted process gas temperature is equal to ambient air temperature as outlined in the definition of delta temperature in section 3.0 of Appendix K is not correct. The commenter noted that for an emitted gas to be detected by an OGI camera, a difference in temperature must exist between the emitted gas temperature and the background temperature.

Response I-22-27: The OGI process is influenced by three different temperatures: the temperature of the emission process gas, the temperature of the background, and the temperature of ambient air. The commenter is correct in stating that a delta-T must exist between the emission process gas temperature and the background temperature in order for the emissions to be detected by an OGI camera. However, the statement in section 3.0 of Appendix K is also correct since the practice of assuming the process gas temperature is equal to ambient air temperature (not background temperature) is an acceptable practice, as the temperature of the process gas when it is released will quickly equilibrate to the surrounding ambient air temperature.

#### ***22.3.8 Repair Definition***

Comment: Three commenters (0561-TRICORD, 0808-API, 0831-AXPC) recommended tweaks to the definition of repair or for the definition to be removed from Appendix K entirely because it will be addressed in the referencing subpart. One commenter (0808-API) further noted that while Appendix K appropriately requires identification of leaking components, it does not address repair.

Response I-22-28: EPA agrees that the definition of repair will be addressed in referencing subparts. We have removed the definition from Appendix K.

#### ***22.3.9 Survey Terminology***

Comment: A commenter (0463-Southern Ute Indian Tribe, Colorado (Southern Ute)) stated that throughout the proposed protocol EPA uses the term "survey" without defining exactly what constitutes a survey. The commenter stated that it's often unclear whether the term refers to the process of surveying an entire site or whether the survey of each distinct affected facility is itself considered one complete survey. The commenter further noted that the consequences of this definition are great because it affects the training requirements of section 10.0, which could be incredibly onerous or adequate depending on what a survey is. The commenter requested EPA define "survey" to provide clarity.

Response I-22-29: In response to comments on the November 2021 proposal, EPA updated the terminology used in Appendix K, including in the training requirements in section 10.0. EPA has updated the training criteria to be based on hours of surveying instead of numbers of surveys. EPA has maintained the terminology of survey as appropriate to refer to the process of using an OGI camera to determine if there are leaks. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal for more information.<sup>21</sup>

## **22.4 OGI Camera Specifications**

### ***22.4.1 Manufacturer Certification***

Comment: Several commenters (0599-MSD, 0782-BHE, 0808-API, 0814-IPAA, 1391-INGAA, 1458-IES) requested clarification that the OEM is (or can be) responsible for designing equipment to the section 6.0 performance standards prior to sale of the equipment. Some commenters (0599-MSD, 0954-FLIR) noted that under NSPS OOOOa, the major camera manufacturers have published documents indicating compliance with the "initial verification" requirements of the rule following third-party testing.

One commenter (0782-BHE) noted that equipment operators should be responsible for daily instrument checks to verify operation according to the OEM specifications, while another commenter (1391-INGAA) requested that the obligations for OEM and ongoing operator requirements be clarified. One commenter (0782-BHE) suggested that most section 6.0 requirements can be satisfied under field conditions by a third-party study. The commenter recommended that the required series of operator performance testing is avoidable if the OEM performs testing and provides documentation of acceptable test results.

Response I-22-30: Regarding responsibilities for demonstrating compliance with the performance specifications outlined in section 6.0 of Appendix K, EPA has clarified that the initial testing to demonstrate compliance with the specifications can be performed by the owner or operator, the camera manufacturer, or a third party. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal.<sup>22</sup>

Comment: A commenter (0814-IPAA) stressed that small businesses do not have access to advanced laboratories and/or the funding necessary to purchase, construct, operate, or maintain the proposed initial performance verification as required in section 6.1.2.

Response I-22-31: Regarding responsibilities for demonstrating compliance with the performance specifications outlined in Section 6.0 of Appendix K, EPA has clarified that the initial testing to demonstrate compliance with the specifications can be performed by the owner or operator, the camera manufacturer, or a third party. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal.<sup>23</sup>

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<sup>21</sup> See 87 FR 74837-47838 (December 6, 2022).

<sup>22</sup> See 87 FR 74839 (December 6, 2022).

<sup>23</sup> See 87 FR 74839 (December 6, 2022).

## ***22.4.2 Camera Configurations for Initial Certification***

Comment: A commenter (0808-API) stated that requiring the testing in section 6.2 for each individual camera is unnecessary since all cameras within a particular model are the same. The commenter stated that some camera configuration changes, as exemplified in the definition of camera configuration, can impact detectability (e.g., changes to sensitivity setting or camera lens) while others will not (e.g., whether camera is hand-held or mounted on a tripod) and the detection limit demonstration is only needed for each configuration that could impact the detection limit.

Response I-22-32: EPA agrees with the commenter that a particular camera model only needs to be tested once, and that each individual camera does not need to be tested. We have updated section 6.1 to indicate that each camera model must meet the specifications in section 6 and added section 8.3.1 to clarify that operating envelopes are specific to a camera model. EPA has further clarified in section 6.1 that the initial specification testing must be performed for each camera operating mode (e.g., standard versus high sensitivity or enhanced). In section 8.3.2 we have clarified that operating envelopes need to be developed for all potential configurations that could affect the detection limit.

## ***22.4.3 Detection Limits***

### ***22.4.3.1 Detection Limit Different from Previous Detection Limits***

Comment: Commenters (0808-API, 1391-INGAA) alleged that there are inconsistencies regarding detection limits. Two commenters (0607-AENV, 0718-Tora) pointed out that EPA previously established that bimonthly surveys, using a minimum detection sensitivity level of 60 grams per hour (g/hr), are equivalent to an EPA Method 21 based LDAR program at a leak definition of 500 ppmv.<sup>24</sup> Additionally, the commenters (0607-AENV, 0718-Tora, 0808-API) argued there is no reason for changing the minimum detection limit demonstration (and possibly having to replace some cameras), requiring new operating envelope determinations, and potentially requiring changing procedures and permits that already use the NSPS OOOOa requirements. One commenter (0808-API) suggested that the minimum detection limit requirement from §60.5397a(c)(7)(i)(B) be allowed as an alternative to the proposed section 6.1.2 minimum detection limit and that the operating envelope determination procedure in section 8.5 be revised accordingly. Similarly, another commenter (0782-BHE) contended the AWP Monte Carlo assessment determined that 60 g/hr was an adequate detection level for methane, but EPA has reduced this to 17 g/hr. This change appears to be based on Monte Carlo simulations and Colorado State University (CSU) testing; EPA has not rationalized the need for this level of detection even if the camera can achieve these lower detection levels.

Response I-22-33: EPA disagrees with the commenters. EPA acknowledges that the commenters are correct about the minimum detection sensitivity in the final rule for the Alternative Work Practice to Detect Leaks from Equipment.<sup>25</sup> Because OGI cameras do not measure in ppmv and the ability to observe leaks is greatly influenced by factors such as wind, thermal background, and distance, it can be difficult to determine the ppmv threshold that an OGI camera will be able

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<sup>24</sup> This is the equivalence in the AWP of the General Provisions of part 60.

<sup>25</sup> 73 FR 78199 (December 22, 2008).

to see. EPA has continued to study OGI cameras since the time that the AWP was finalized, as reflected in the TSD for Appendix K, and the detection thresholds specified in Appendix K represent our best understanding of the capabilities of current MWIR OGI cameras.

EPA notes that it has made no changes to the OGI requirements in NSPS OOOOa, and as such, there should be no need to change procedures and permits for those sites. Additionally, based on testing conducted by EPA as part of the development of the Appendix K TSD, we expect that cameras that meet the threshold in NSPS OOOOa will also meet the requirements outlined in Appendix K.

#### 22.4.3.2 Detection Limit Compounds

Comment: Two commenters (0607-AENV, 0718-Tora) indicated that the inclusion of chemical-specific sensitivity thresholds limits the pool of acceptable OGI cameras. Another commenter (0782-BHE) declared that establishing a lower detection limit for methane than for butane is not justified by the MWIR absorption spectra or laboratory/field test data demonstrations. The first commenters (0607-AENV, 0718-Tora) encouraged EPA to provide additional data, discussion, and justification to support a significant change.

Response I-22-34: See discussion in section XIV.B.2 of the preamble to the final rule which details EPA's final standards related to OGI camera detection limits. More information on detection limits can also be found in the final TSD for Appendix K.

EPA notes that it has only included sensitivity thresholds for methane and either propane or butane. This is to ensure that OGI cameras used with Appendix K will be able to image leaks of both methane and VOCs. EPA also notes that sector-specific performance requirements can be considered on a regulation specific basis when EPA revises a subpart to reference Appendix K. Such sector-specific performance requirements would be defined in the referencing subpart and not in Appendix K.

Comment: Two commenters (0607-AENV, 0718-Tora) pointed out that for certain process streams with very low hydrocarbon content, the calculated mass flow rate may be too low to effectively utilize a hydrocarbon OGI camera. For example, some streams associated with an amine unit at a natural gas processing plant are very low in hydrocarbon content but relatively high in carbon dioxide content. For such streams, the use of an OGI camera capable of visualizing carbon dioxide (e.g., FLIR GF343) may be appropriate.

Response I-22-35: Appendix K was developed for determining leaks of VOCs and methane, and as such, the detection thresholds in Appendix K are specific to that effort. The spectral range of the filter of the FLIR GF343 is not appropriate for monitoring methane and a broad range of VOCs. While we acknowledge that this OGI camera may be a useful tool for monitoring carbon dioxide emissions, it falls outside the scope of Appendix K.

If an owner or operator has streams that cannot be monitored with an OGI camera meeting the requirements of Appendix K, the owner or operator may use EPA Method 21 or apply for alternative monitoring under §60.13(i).



Comment: One commenter (0954-FLIR) argued that while propane gas is referenced as a gas to be used for the daily verification test, it was not established as a gas to be imaged by OGI technology in any other sections of Appendix K. The commenter further noted that understanding that a camera developed around response factors will be able to image propane if it can detect methane, the inclusion of propane in this section supports the argument that a camera's detection capabilities and operating envelope requirements should be based only on the lower response factor gas. The commenter asked for clarification on the reasoning behind including propane and if including propane as a test gas will allow for testing of the "lowest response factor gas" in the operator envelope testing of the technology.

One commenter (0599-MS) questioned why EPA selected butane instead of propane for evaluation of performance, as propane will be the predominant constituent in natural gas compared to butane.

Two commenters (0782-BHE, 0954-FLIR) noted that in section 1.1 (Analytes), two gases are mentioned specifically, methane and ethane, along with general VOCs, while in various places within Appendix K, other gases are mentioned specifically including butane and propane in sections 6.1.1, 6.1.2, 6.2.2, 8.5.5, and 9.1.3. The commenters recommended adding these gases to the analyte list for clarity. One of the commenters (0782-BHE) noted that if the camera specification requires a minimum detection level of 18.5 g/hr yet butane is omitted as an analyte, this would indicate uncertainty and confusion regarding method development. The commenter further argued that Table 4-11 in the Appendix K TSD and Appendix K itself as written is misleading regarding compound applicability. The commenter referenced the December 14, 2021, Proposed Appendix K Webinar which expanded the analyte applicability to include hazardous air pollutants, which are not contained in Appendix K. The commenter also recommended removing ethane as an analyte, arguing that ethane had been specifically excluded from the definition of VOCs, has limited activity as a greenhouse gas, is much less abundant than methane, has a lifetime of only a few months, and is less efficient at absorbing radiation relative to mass.

The commenter (0782-BHE) argued that this supported the premise that an OGI protocol method should apply to all compounds having suitable absorbance in the MWIR spectrum and be performance based with criteria depending on the regulatory context.

Response I-22-36: EPA disagrees with the commenters. Appendix K is suitable for measuring a broad range of compounds with peaks in the MWIR spectrum. Propane is used as the reference gas in developing response factors. Propane is also a gas that can be visualized by OGI cameras with Appendix K because the response factor of propane, 1, would meet the criterion in section 6 of Appendix K. Additionally, methane and ethane are called out specifically in the analyte section because they are not VOC. EPA has not listed out individual VOC and has instead listed VOC generically, but the analytes covered by the term VOC include propane, butane, and other volatile organic compounds, including those hazardous air pollutants that are VOC. EPA does not think that it is necessary to list all individual VOC that can be imaged in Appendix K, as an OGI camera cannot differentiate between different compounds. EPA is retaining ethane as an analyte that can be monitored with Appendix K because OGI cameras covered by Appendix K can see leaks of ethane.

EPA notes that it has included sensitivity thresholds for methane and either propane or butane. This is to ensure that OGI cameras used with Appendix K will be able to image leaks of both methane and VOCs. While methane is less sensitive to detection for OGI cameras that operate in the 3.2-3.4 micron range, we have no empirical evidence to prove that the operating envelope for butane will always be better than the operating envelope for methane. Therefore, in the final rule EPA is maintaining the requirement to test both methane and either butane or propane during development of the operating envelope.

In response to comments received on the November 2021 Proposal, EPA updated Appendix K to allow the specification testing in section 6 and the development of operating envelopes in section 8 to be conducted with either butane or propane. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal for more information related to response factors.<sup>26</sup>

#### 22.4.3.3 Detection Limit Levels

Comment: One commenter (1458-IES) acknowledged that the spectral range of infrared radiation measured by the OGI camera must overlap with an absorption peak for a chemical compound of interest. Another commenter (0782-BHE) maintained that OGI has application to different regulatory regimes (e.g., mitigation of greenhouse gases/methane, VOC, or hazardous air pollutants) and the protocol should consider different mass-based performance thresholds depending on the pollutant. The commenter also acknowledged that methane and greenhouse gases should not be subjected to the same leak threshold rate as VOC and hazardous air pollutants. The commenter requested that EPA establish Appendix K applicability with the corresponding analytes, minimum detection levels, response factors, or performance specifications.

Response I-22-37: EPA acknowledges that OGI has application to different regulatory regimes and notes that Appendix K is specific to the use of OGI in leak detection. The detection thresholds in Appendix K were developed based on common cooled MWIR OGI cameras, which can see both methane and VOCs. The detection level of these OGI cameras is not expected to vary much if the spectral filter remains in the same range (around 3.2-3.4 micron). Appendix K does not set different thresholds for different compounds other than noting what the OGI cameras need to be capable of detecting.

The emissions reductions achieved using an OGI camera are specific to each subpart where Appendix K is applied. The analysis for the individual subpart is where the emissions reductions for individual compounds based on the detection capabilities of the camera can be used to design the frequency of inspection using an OGI camera. EPA notes that sector-specific performance requirements can be considered on a regulation specific basis when EPA revises a subpart to reference Appendix K. Such sector-specific performance requirements would be defined in the referencing subpart and not in Appendix K.

Comment: Two commenters (0604-Providence, 1458-IES) acknowledged that if various subparts in 40 CFR parts 60, 61, 63, and 65 reference Appendix K then different detection limits (minimum emission rate detectable by an OGI camera model) may be needed. First, a different target compound will have different sensitivity even for the same OGI camera model. Second,

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<sup>26</sup> 87 FR 74839 (December 6, 2022).

the objective of a particular subpart may be different (e.g., a subpart aimed at regulating air toxics may be more stringent than a subpart aimed at regulating methane). Therefore, the commenter suggested that EPA move the target compound (methane in this case, or methane and butane if the EPA would like to maintain both target compounds) and associated minimum emission rate to the regulation itself (e.g., NSPS OOOOb). This should not affect the content of Appendix K, but it will make it more generic and usable by future rulemakings (i.e., by other applicable subparts).

Response I-22-38: The detection thresholds in Appendix K were developed based on common cooled MWIR OGI cameras, which can see both methane and VOCs. The detection level of these OGI cameras is not expected to vary much if the spectral filter remains in the same range (around 3.2-3.4 micron). Appendix K does not set different thresholds for different compounds other than noting what the OGI cameras need to be capable of detecting. EPA notes that it has only included sensitivity thresholds for methane and either propane or butane, which are surrogates for other VOCs, as most VOCs have a peak in the same portion of the infrared spectrum. This is to ensure that OGI cameras used with Appendix K will be able to image leaks of both methane and VOCs.

The emissions reductions achieved using an OGI camera are specific to each subpart where Appendix K is applied. The analysis for the individual subpart is where the emissions reductions for individual compounds based on the detection capabilities of the camera can be used to design the frequency of inspection using an OGI camera. EPA notes that sector-specific performance requirements can be considered on a regulation specific basis when EPA revises a subpart to reference Appendix K. Such sector-specific performance requirements would be defined in the referencing subpart and not in Appendix K.

Comment: Commenters (0808-API, 0604-Providence, 0719-Opgal, 0831-AXPC) asserted that the detectability test for methane and butane emissions as specified in section 6.1.2 of Appendix K is not needed. One commenter (0719-Opgal) suggested that defining a criterion at one set of conditions is not sufficient to ensure a reasonable envelope of performance and proposed adding a higher emission rate requirement in another set of conditions to reflect more realistic conditions. Another commenter (0561-TRICORD) suggested that the detectability test for methane and butane be relaxed to a one-time or annual verification to reduce the burden on operators.

Another commenter (0604-Providence) recommended a different approach to minimum detection capability for OGI cameras, suggesting EPA replace the reference of “and butane” and the associated numeric minimum emission rate of “18.5 g/hr” with “or target compound and minimum emission rate if specified by an applicable subpart.” The commenter acknowledged that for the most commonly used cooled MWIR OGI cameras, the sensitivity for butane is significantly higher than methane, and that for the FLIR GF320 OGI camera model, the response factors are 0.297 and 1.011 for methane and n-butane respectively (indicating that butane is much easier to detect than methane).

Response I-22-39: EPA disagrees with the commenters that the detectability test in section 6.1.2 is not needed. It is important to ensure that each OGI camera model has a minimum detectability level before an owner or operator uses it for compliance with the survey requirements in a

subpart referenced by Appendix K. Additionally, EPA has only prescribed one set of conditions in section 6.1.2 because this is a performance specification confirmation of the particular camera model, which EPA notes is a one-time test to qualify the camera for use, and this testing can be performed by the manufacturer, the owner or operator, or a third-party. The testing in section 6.1.2 is not intended to dictate the full range of conditions a survey can be conducted under. The operating envelopes developed under section 8 of Appendix K is intended to set the range of conditions appropriate for conducting surveys.

EPA has only included sensitivity thresholds for methane and either propane or butane, which are surrogates for other VOCs, as most VOCs have a peak in the same portion of the infrared spectrum. This is to ensure that OGI cameras used with Appendix K will be able to image leaks of both methane and VOCs. sector-specific performance requirements can be considered on a regulation specific basis when EPA revises a subpart to reference Appendix K. Such sector-specific performance requirements would be defined in the referencing subpart and not in Appendix K.

EPA has reviewed the detection limits used in Appendix K. See discussion in section XIV.B.2 of the preamble to the final rule which details EPA's final standards related to OGI camera detection limits. More information on detection limits can also be found in the final TSD for Appendix K.

Comment: Commenters (0607-AENV, 0718-Tora) explained that the removal of the VOC concentration threshold from the definition of “in VOC service”, expands the population of components at a natural gas processing plant that would be subject to LDAR requirements.<sup>27</sup> The commenters indicated that this change requires Appendix K to be flexible and allow for the utilization of the OGI technology best suited for the streams being monitored. Specifically, EPA should remove the minimum detection criteria for specific hydrocarbon compounds (i.e., 17 grams per hour for methane and 18.5 grams per hour for butane) and instead retain the flexible performance criteria outlined in the current AWP. Under the AWP, the minimum concentration of detectable chemicals in a gas stream is multiplied by the selected detection sensitivity level (e.g., 60 grams per hour) to determine the mass flow rate for the performance of the daily instrument check.

Response I-22-40: Since the time that the AWP was finalized, EPA has continued to research and conduct studies on minimum detection sensitivity levels, and we have learned more about the detection capabilities of OGI cameras. Field conditions, especially delta-T, wind speed, and distance, play an important role in the ability of an OGI camera operator being able to observe leaks that are present. We have based Appendix K and the detection levels within Appendix K on the best available information.

EPA notes that it has only included sensitivity thresholds for methane and either propane or butane, which are surrogates for other VOCs, as most VOCs have a peak in the same portion of the infrared spectrum. This is to ensure that OGI cameras used with Appendix K will be able to image leaks of both methane and VOCs.

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<sup>27</sup> Commenter cited to the November 2021 Proposed rule, 86 FR 63182 (November 15, 2021).

#### 22.4.3.4 Constituent Percent Criteria

Comment: Commenters (0607-AENV, 0718-Tora, 0782-BHE) declared that any minimum performance specification should be based on the concentration of detectable chemicals within the gas stream, not the count of such chemicals. The commenters provided similar example scenarios: a process gas stream has 10 constituents, where eight of the components are detectable by the OGI camera, but only account for 5-10% by weight of the overall gas stream. The OGI camera would meet the minimum performance specification for the process stream (>75% by count) but would not be effective at detecting leaks from the process stream.

Response I-22-41: Regarding the concentration of detectable chemicals within the gas stream as required in section 6.1.1 of Appendix K, EPA has clarified that 75 percent refers to the amount of constituents by volume. See section VI.C of the December 2022 Supplemental Proposal for clarification on this requirement.<sup>28</sup>

Comment: Commenters (0808-API, 0831-AXPC) advocated for the spectral range requirements in Section 6.1.1. One commenter (0808-API) called attention to refineries and other complex processes whose monitored components can contain many hydrocarbons with a range of individual response factors. The commenter stated that the OGI methodology should be feasible for these processes when there is a limited ability to precisely characterize stream compositions, and the methodology should balance both the camera's ability and the range of components that may be in an emission stream. The commenter contended that for upstream operations there is usually a dominant hydrocarbon in the streams being monitored and, therefore, the simpler, less burdensome requirement in §60.5397a(c)(7)(i)(A) is appropriate for those operations.

Response I-22-42: EPA acknowledges the support from the commenters on the approach taken in Appendix K. We recognize that some streams at refineries and within other sectors can be complex and difficult to characterize. However, it is imperative that an owner or operator ensure that any components monitored by an OGI camera be limited to those where an OGI camera can visualize any emissions from the streams in contact with the components.

In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal, which is similar to the approach taken in NSPS OOOOa. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>29</sup>

#### ***22.4.4 Calibrations and Non-Uniformity Correction***

Comment: Commenter (0561-TRICORD) called attention to an OEM design characteristic, the Non-Uniformity Correction (NUC).<sup>30</sup> The commenter attested that this characteristic was not properly acknowledged. The NUC is a required and routine calibration that is not acknowledged

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<sup>28</sup> See 87 FR 74840 (December 6, 2022).

<sup>29</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

<sup>30</sup> NUC adjusts for minor detector drift that occurs as the scene and environment change.

in the proposed Appendix K section 7.1. Another commenter (0831-AXPC) supported section 7.0 in its current form.

Response I-22-43: EPA acknowledges that NUC can be important component of routine maintenance and calibrations for OGI cameras. While not specifically mentioned in Appendix K, EPA has revised the language in section 7.1 to state that operators should follow manufacturer recommendations regarding maintenance and calibration, as appropriate.

Comment: Commenters (0561-TRICORD and 0782-BHE) indicated that Appendix K Section 10.2.1.4 overstates the calibrations required for proper operation and maintenance. One commenter (0561-TRICORD) explained that no calibrations beyond the NUC and temperature calibrations are necessary.

Response I-22-44: EPA agrees that many OGI cameras do not need routine calibrations. The language in section 10.2.1.4 has been revised to remove the word calibration.

Comment: A commenter (0911-NDPC) stated that if a company conducts OGI surveys using company personnel, EPA should require that the camera calibration and maintenance be addressed in the facility's monitoring plan and should follow the manufacturer's recommendation.

Response I-22-45: EPA has revised the language in section 7.1 to state that operators should follow manufacturer recommendations regarding maintenance and calibration, as appropriate.

#### ***22.4.5 Equipment Needed for Certification Testing***

Comment: A commenter (0561-TRICORD) asked if the release orifice description in Section 6.2.3 refers to the outside or inside ¼ inch diameter.

Response I-22-46: The language in section 6.2.3 has been revised to specify the inner diameter.

Comment: A commenter (0561-TRICORD) suggested that an infrared thermometer should be an accepted alternative to the T-type surface skin thermocouple for measuring the background immediately behind the test gas as described in section 6.2.9. The commenter asserted that infrared thermometers are more accurate (0.3 °C vs. 1.0 °C) and have a slower response time.

Response I-22-47: EPA chose not to include infrared thermometers in section 6.2 of Appendix K, because an infrared thermometer is essentially the same technology as an OGI camera. Our intention was to verify the actual temperature using a method that would not be susceptible to the same interferences.

Comment: Commenters (0808-API, 0831-AXPC) suggested that the required National Institute of Standards and Technology (NIST) traceability accuracy of 5 percent required for the mass flow controller or rotameter in Section 6.2.4 seems unnecessary. NIST traceability is not specified for any other instrumentation.

Response I-22-48: In the final rule, EPA has removed the requirement for NIST traceability. Instead, we have changed this requirement to be “traceable to the International System of Units through an unbroken chain of comparisons” and have included this requirement on the distance measurement tool and thermocouples as well as the flow meter. We have also added calibration and standardization requirements for the meteorological station. These requirements are in place to minimize the error in the method and are critically important for producing accurate, reliable data.

Comment: Commenters (0808-API, 0831-AXPC) suggested that the requirement that the weather information described in Section 6.2.6 be obtained from a weather station within 1 mile of the test location seems unnecessary. Commenters (0808-API, 0831-AXPC) stated that in many cases National Weather Service stations will be the basis for this data, and the testing facility will not have ready access to the instrumentation specifications at that weather station or the ability to influence that equipment. The commenters (0808-API, 0831-AXPC) therefore recommend that weather data obtained from a National Weather Service Station located within 1 mile of the test location be allowed without requiring the information specified in Section 6.2.6.1 through 6.2.6.5 to be collected. Commenter (1391-INGAA) stated that the requirements limit the use of current equipment that satisfies existing NSPS OOOOa requirements.

Response I-22-49: The language in section 6.2.6 was revised in the December 2022 Supplemental Proposal to require a meteorological station at the test site. As this is a one-time requirement for each camera model, EPA does not consider an onsite meteorological station to be an onerous requirement. Because this demonstration is the basis for proving that the OGI camera model has the ability to meet the performance criteria specified in the rule, it is imperative that the data collected be accurate and of known quality, and it is important to know the sensitivity of the instrumentation used to collect the required data.

The requirements in section 6.2.6 of Appendix K do not limit the use of current equipment that satisfy existing NSPS OOOOa requirements. NSPS OOOOa does not require the use of Appendix K.

#### ***22.4.6 Response Factors***

Comment: One commenter (0782-BHE) questioned the selection of propane as the reference compound for response factor tests noting that natural gas can contain several or all alkanes that improve response. The commenter argued that since propane is one of the largest optical depth gases available, methane should be selected as the reference specification for this approach.

Response I-22-50: EPA disagrees with the commenter. Appendix K is meant to be more broadly applicable than for just finding leaks of methane and other compounds found in natural gas. Propane is an easily obtained gas that is neither a greenhouse gas nor a hazardous air pollutant, and therefore, it is a good candidate for testing relative responses of other gases. Additionally, there has already been work to date, as included in the Appendix K TSD, using propane as the reference gas.

Comment: One commenter (0954-FLIR) noted that the document commonly refers to the response factors of gases and recommends adding a table with response factor values for methane, ethane, and other analytes, such as the one available here: <https://www.tandfonline.com/doi/full/10.1080/10962247.2016.1244130>.

Response I-22-51: The definition of response factor was modified in response to comments. Specifically, EPA has indicated that response factors are camera model specific. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal for more information related to response factors.<sup>31</sup> Because response factors are camera model specific, response factors cannot be included within Appendix K.

Comment: One commenter (0561-TRICORD) noted that most OGI cameras are qualitative rather than quantitative and questioned how response factors would be developed for qualitative cameras. The commenter further questioned that if a camera can image a propane leak at 40 feet distance, would the “other majority” of chemicals need to be imaged at a distance of 10 feet or more?

Response I-22-52: In response to comments on the November 2021 proposed rule, as part of the December 2022 Supplement Proposal, EPA developed Annex 1 to Appendix K, which is a methodology for the development of response factors for OGI cameras. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal for more information related to response factors.<sup>32</sup>

EPA is clarifying that the operating envelope for the OGI camera model developed in accordance with section 8 is applicable to any compound being monitored. The operating envelope does not need to be adjusted for each individual compound in the emissions stream.

Comment: One commenter (0719-Opgal) believed section 6.1.1 should only need to state that the spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest. The commenter noted that if no sufficient overlap exists, the OGI camera will not be able to meet the performance-based requirements in 6.1.2. The commenter stated the 0.25 response factor requirement is not necessary and would be impossible to verify.

Response I-22-53: EPA disagrees with the commenter. While it is important for the target compound to have an absorption peak within the spectral range of radiation measured by the OGI camera, there are many emission streams that consist of a variety of compounds. It is important that Appendix K provide clarity on when it is appropriate to use an OGI camera to monitor emissions from these streams, and when the OGI camera is not expected to respond at appropriate levels. Therefore, we have maintained the specification that the majority (>75% by volume) of compounds in the emissions stream must have a response factor of at least 0.25, when compared to the response factor of propane.

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<sup>31</sup> 87 FR 74839 (December 6, 2022).

<sup>32</sup> 87 FR 74839 (December 6, 2022).



## 22.5 Operator Training

### 22.5.1 General Opposition on Training Requirements

Comment: Commenters (0463-Southern Ute, 0607-AENV, 0718-Tora, 0749-PAW, 0782-BHE, 0831-AXPC) considered the OGI camera operator training requirements in section 10.2.2 of Appendix K to be expensive, prohibitive, and unnecessary. One commenter (0463-Southern Ute) stressed that the minimum field training elements for the initial OGI camera operator training are burdensome and will greatly increase the cost of the leak detection program. The commenter recommended lower minimum training requirements.

Several commenters suggested that the training requirements of Appendix K would result in numerous difficulties in implementation. One commenter (1458-IES) suggested that the stringent training requirements would result in significantly diminished stakeholder implementation of next generation technology, with many operators reverting to older leak detection techniques. Another commenter (0808-API) contended that the extensive training requirements could make implementation impractical and inefficient. The commenter noted that the significant overhead costs involved in completing the training requirements reduce the potential economic benefits of transitioning to OGI as an alternative leak detection technique.

Additionally, a commenter (0750-Flogistix) expressed reservations over feasibility for small oil and gas producers, while another commenter (0934-Leak Surveys, Inc. (LSI)) argued that while the length of training is important, the most important qualification of a successful OGI camera operator is the desire to find leaks. This implies that different trainees may have different training needs. A third commenter (0924-SBA) noted that several small businesses had expressed significant concerns about the extra burden Appendix K would place on their operations, and that training requirements for new operators would significantly reduce the capacity of the industry.

One commenter (0786-Enerplus) suggested that the training and qualification requirements currently outlined in Appendix K will limit the operator's ability to find qualified OGI operators, thereby restricting the pool of trained staff available to implement the method. Another commenter (0934-LSI) agreed that the stringent training requirements in Appendix K will result in disqualification of field technicians, thereby reducing the number of qualified OGI operators available to conduct surveys. The commenter stated that this would result in operators reverting to older technology like EPA Method 21. A third commenter (0808-API) indicated that the extensive training requirements of Appendix K will increase the dependence of operators on third-party OGI camera operators, and since third party operators may not be trained or allowed by operators to attempt a first repair upon leak detection (as under NSPS OOOOa programs), the leak repair will be delayed resulting in more emissions.

Response I-22-54: In response to comments received on the November 2021 Proposal, EPA updated the training requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>33</sup>

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<sup>33</sup> See 87 FR 74837-74838 (December 6, 2022).

### ***22.5.2 Site Survey Criterion***

Comment: Commenters (0782-BHE, 0808-API, 0831-AXPC, 0954-FLIR) requested clarification on the definition of a site survey and indicated that the duration of a site survey varies depending on the complexity of the site to be monitored. Thus, monitoring a “site” can take a brief time for one OGI operator (minutes or hours) or require many fulltime OGI operators and take months to complete. One commenter (0749-PAW) stated that Appendix K does not define a site survey adequately and suggested that site surveys can vary widely for upstream, midstream and downstream facilities. Further, the commenter suggested a hybrid training system of in-field and classroom training would be the ideal for OGI trainees.

Commenters (0808-API, 0814-IPAA) indicated a lack of clarity on whether site surveys require sites with a variety of equipment sets or to be significantly different from each other. One commenter (0599-MSC) stated that the training requirements will be difficult and costly for smaller companies that don't have multiple cameras/camera operators to comply, and the number of site surveys conducted in tandem with a senior operator seems arbitrary and overly onerous. The commenters (0599-MSC, 0808-API, 0814-IPAA) suggested replacing the number of surveys criterion with a set number of survey hours for each training phase because a survey may vary greatly in duration depending on the type of facility being surveyed. Another commenter (0916-AOGA) recommended that the term site be defined to mean a single wellhead or single piece of equipment.

One commenter (0561-TRICORD) proposed quantifying new trainee requirements on the time spent using the OGI camera, with 100 hours as a training requirement rather than 100 surveys.

Response I-22-55: In response to comments received on the November 2021 Proposal, EPA removed the site survey terminology in the training requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>34</sup>

### ***22.5.3 Recertification Requirements***

Comment: Commenters (0607-AENV, 0718-Tora, 0814-IPAA) found the OGI operator recertification requirements in section 10.5 of Appendix K to be unnecessary and excessive, with the recommendation that the recertification for an experienced OGI operator be limited to the final site monitoring survey test and the annual refresher training, thereby eliminating the repetition of full classroom training.

A commenter (0782-BHE) questioned the basis for the retraining requirements outlined in section 10.5 and expressed concern on the time spent by experienced OGI camera operators in completing lengthy repeat training sessions. The commenter considered these issues to be significant enough to prevent the implementation of OGI as a viable alternative to existing leak detection methodologies.

One commenter (0463-Southern Ute) also found the operator recertification process to be onerous and expressed concern over the potential expenditure. Another commenter (0561-

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<sup>34</sup> See 87 FR 74837-74838 (December 6, 2022).

TRICORD) did not object to the retraining requirements of section 10.5 but suggested extending the period of inactivity from 12 months to 24 months.

Response I-22-56: In response to comments received on the November 2021 Proposal, EPA has updated the recertification criteria of Section 10.5 in the training requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>35</sup>

#### ***22.5.4 Initial Training Requirements for Experienced Camera Operators***

Comment: Commenters (0808-API, 0831-AXPC) questioned the requirement for experienced OGI camera operators to go through the entire initial training program to meet Appendix K requirements. The commenter recommended that an OGI camera operator with at least 24 hours of OGI monitoring experience in the previous 12 months, but no previous Appendix K experience, only be required to go through the refresher level of training rather than the full initial training and then pass the field training final test.

Response I-22-57: In response to comments received on the November 2021 Proposal, EPA proposed to allow previous experience to be substituted for certain initial training requirements in the December 2022 Supplemental Proposal for Appendix K. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>36</sup>

#### ***22.5.5 Classroom Training***

Comment: Commenters (0750-Flogistix, 0793-PBPA, 0814-IPAA, 0924-SBA, 0945/1373-JOFA) indicated that the annual classroom training refresher for OGI camera operators is an excessive requirement. Some commenters (0793-PBPA, 0808-API) recommended that the refresher training be required every 3 years. Another commenter (0599-MSD) stated that while they generally support refresher training, camera operators should be exempted from the annual refresher training requirement if the operator is conducting frequent surveys throughout the year and pass all performance audits.

Response I-22-58: In response to comments received on the November 2021 Proposal, EPA updated the training requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>37</sup>

Comment: Several commenters (0782-BHE, 0802-Kraken, 0808-API, 0814-IPAA, 0911-NDPC, 0954-FLIR, 0945/1373-JOFA) requested clarification on the references to classroom training in sections 10.2 and 10.3 of Appendix K. Commenters (0808-API, 0831-AXPC, 0954-FLIR) recommend that virtual or online training sessions be allowed as viable substitutes for in-person classroom training. A commenter (0954-FLIR) also requested further information on the

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<sup>35</sup> See 87 FR 74837-74838 (December 6, 2022).

<sup>36</sup> See 87 FR 74837-74838 (December 6, 2022).

<sup>37</sup> See 87 FR 74837-74838 (December 6, 2022).

classroom training elements outlined in section 10.2.1, including guidance on the teaching time per element, content per element and classroom testing for efficacy.

Response I-22-59: EPA does not intend to prescribe the time or content of the required classroom training beyond the outline provided in Appendix K. While we recognize that the theory behind the operation of OGI cameras is important and should be covered in any comprehensive training program, we believe that the final field test and performance audits will be the true demonstration of an operator's ability. Therefore, we are providing flexibility for people to design their own classroom programs, as long as each program covers the topics outlined in section 10.0 of Appendix K.

Additionally, in response to comments received on the November 2021 Proposal, EPA clarified the classroom training requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>38</sup>

### **22.5.6 Field Test**

Comment: A few commenters raised objections over the requirement to be 100% accurate during the final monitoring survey field test. One commenter (0911-NDPC) noted that Appendix K in its current form requires the camera operator to be 100% accurate during training, which does not account for human error and situational factors. Another commenter (0782-BHE) raised the same point and referenced studies performed at Colorado State University where experienced OGI camera operators did not have 100% leak detection. Other commenters (0808-API, 0831-AXPC) recommended that the accuracy criterion be revised to at least 90% agreement or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified. One of the commenters (0808-API) also recommended that if 90% agreement is not achieved, the senior operator should work with the trainee on the reasons for the failure followed by a repeat test. In the case of a second failure, the trainee should be required to go through the refresher level of training prescribed in section 10.3 of Appendix K before retaking the final test. Another commenter (0599-MSD) noted that the requirement to achieve zero missed persistent leaks is higher than the amount achieved by all levels of experience in the studies presented at EPA's Optical Gas Imaging Stakeholder Workshop in November 2020. The commenter suggested that the threshold be revised to an allowable percentage of missed persistent leaks rather than an arbitrary number. Other commenters (0607-AENV, 0718-Tora) stated that determination of suitability for independent monitoring should be based on observations and comparative monitoring, as determined by the senior OGI camera operator.

Commenters (0808-API, 0831-AXPC) also expressed concern over the length of the final field test and recommended that the final test be reduced to one hour in duration.

Response I-22-60: In response to comments received on the November 2021 Proposal, EPA updated the training requirements for Appendix K in the December 2022 Supplemental Proposal.

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<sup>38</sup> See 87 FR 74837-74838 (December 6, 2022).

See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>39</sup>

### ***22.5.7 Performance Audits for Camera Operators***

#### **22.5.7.1 Performance Audit Opposition**

Comment: Multiple commenters (0463-Southern Ute, 0561-TRICORD, 0607-AENV, 0718-Tora, 0749-PAW, 0750-Flogistix, 0782-BHE, 0786-Enerplus, 0808-API, 0814-IPAA, 0831-AXPC, 1458-IES) questioned or opposed the proposed performance audit specifications for OGI camera operators. One commenter (1458-IES) argued that performance audits are unnecessary. Some commenters (0786-Enerplus, 1458-IES) stated that audits provide no additional assurances of enhanced leak identification or effectiveness. Commenters (0749-PAW, 1458-IES) stated that performance audits are not typically supported by precedence in other reference methods, and that the proposed requirements of Appendix K would make the method significantly more onerous than EPA Method 21 or other reference methods. A commenter (0814-IPAA) reiterated that other similar work practice programs, such as EPA Method 21 LDAR monitoring, have been in service for more than 40 years without a similar audit requirement.

Several commenters (0750-Flogistix, 0782-BHE, 0786-Enerplus, 0814-IPAA, 0924-SBA) remarked that the requirements were overly burdensome. One commenter (0782-BHE) objected to the substantive changes from the AWP, inconsistency with EPA Method 21, and “arduous” criteria. Commenters (0782-BHE, 1391-INGAA) supported either significantly streamlining the process or providing additional justification and support for the rationale for the added audit, training, and certification requirements. One commenter (0782-BHE) specifically expressed concern that the cost-effectiveness analysis may not adequately reflect the time required to complete the audits or the impacts to survey personnel.

Other commenters (0463-Southern Ute, 0817-GPA, 0916-AOGA) stated that the proposed audit requirements of Appendix K would effectively require facilities to use contractors instead of in-house personnel. One commenter (0463-Southern Ute) stated that because the audits require senior OGI camera operator surveys to be audited, many companies would be forced to either have two senior OGI operators on staff or rely on third party contractors for each survey. The commenter (0463-Southern Ute) added that if third party contractors are required, this could result in potential delays and would add travel and lodging expense costs. A commenter representing Alaskan production facilities (0916-AOGA) noted that the quarterly requirements would force them to displace their local staff observers with consultants from the Lower 48. The commenter (0916-AOGA) explained that due to the short summer window in Alaska, the risk of assigning local staff who last conducted an OGI survey during the previous summer to first pass a performance audit and then complete the OGI monitoring program at a series of facilities within the summer window would be too great (i.e., if the staff did not pass the audit). The commenter (0916-AOGA) also indicated that the availability of qualified consultants willing to spend the summer conducting OGI surveys at these facilities may be problematic. Another commenter (0814-IPAA) asserted that this would be particularly costly for compressor stations, as services for fugitive emission surveys using OGI are not readily available in many areas of the country, and the cost to bring in equipment from other areas would be prohibitive. The

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<sup>39</sup> See 87 FR 74837-74838 (December 6, 2022).

commenter (0814-IPAA) provided a cost of \$13,400 per year per compressor station. A commenter (0463-Southern Ute) recommended that EPA allow the performance audits being conducted by a third-party qualified OGI camera operator as sufficient for the performance audit requirement. The commenter also suggested that EPA should allow companies to implement their own leak detection training programs internally, without reliance on third party contractors.

Commenters (0749-PAW, 0808-API) pointed out that requiring senior OGI camera operators to also be audited is not a productive use of time. One commenter (0749-PAW) argued that the proposed approach would require senior OGI camera operators to spend more of their time reviewing other operators' work than in the field completing surveys. The commenter (0749-PAW) asserted that if senior OGI camera operators have the training and experience to audit others, they should be excluded from the auditing process. The other commenter (0808-API) stated that because senior OGI camera operators will automatically review monitoring requirements frequently and have an opportunity to identify and correct issues of their own, they should not be required to undergo performance audits.

Several commenters (0561-TRICORD, 0750-Flogistix, 0782-BHE, 0814-IPAA, 0817-GPA, 0916-AOGA) questioned the retraining requirements for OGI camera operators who missed detecting leaks during the performance audit. Commenters (0599-MSC, 0749-PAW, 0808-API, 0817-GPA, 0831-AXPC, 0924-SBA) questioned the requirement that the survey test require a trainee to be 100% accurate. Commenters noted that this level of accuracy is unrealistic, unreasonable, or inconsistent with other aspects of Appendix K. Other commenters (0607-AENV, 0718-Tora, 0750-Flogistix) emphasized that the retraining requirements would include five additional side-by-side comparative surveys and ten additional supervised surveys if one small leak was missed, which is excessive, punitive and burdensome. One commenter (0817-GPA) stressed that there is always some subjectivity to using an OGI camera and that even experienced observers may disagree on whether they recognize a leak. The commenter suggested that EPA require trainee operators to be at least 75% accurate to qualify for independent survey work. Other commenters (0749-PAW, 0808-API, 0831-AXPC) recommended that the criteria be based on 90% accuracy or a difference of no more than one persistent leak if less than ten persistent leaks are identified. One commenter (0561-TRICORD) urged that if a leak is missed by the camera operator being audited, the camera operator ought to be informed that they missed a leak in a specific area and given the opportunity to re-image; the commenter noted that if the operator consistently missed the leak, only then should retraining be required.

One commenter (0808-API) emphasized that failures to observe a leak or to follow some aspects of the monitoring procedure are situation specific, and that general retraining dilutes the focus on the real problem(s) and uses monitoring time and senior resources on issues that are not a problem. Instead, the commenter suggested the requirement should be to specify that retraining is required to address monitoring aspects observed to be an issue during the audit. The commenter also recommended the word "site" be deleted from the retraining requirements in sections 10.4.1.2 and 10.4.2.2 ("required number of site surveys") and recommended, instead, that the monitoring requirements be expressed on a time basis. Another commenter (0718-Tora) similarly insisted that recertification should be based on a reasonable duration of supervised surveys (e.g., 40 hours).

One commenter (0817-GPA) stated that Appendix K is not clear as to what occurs if the comparative monitoring reveals that the senior OGI camera operator performed poorly. A separate commenter (0718-Tora) also noted a scenario where the senior OGI camera operator could erroneously identify missed leaks during video review and recommended that section 10.4.2 should provide that any leaks identified during video review by the senior OGI camera operator as being allegedly missed are not considered leaks for regulatory compliance purposes.

Commenters (0916-AOGA, 1458-IES) noted that the proposed requirements would likely reduce the number of available personnel to conduct surveys. One commenter (0916-AOGA) asserted that the proposed retraining requirements would potentially complicate the scheduling of annual LDAR surveys. The commenter noted that operators try to schedule surveys ahead of planned shutdowns to accommodate the repair of any leaks discovered; the commenter stated that if a camera operator is found to have missed a leak during the quarterly performance audit, the same operator would likely be disqualified from conducting the annual LDAR survey during that year.

One commenter (0599-MSD) was also concerned about a potential shortage of qualified senior OGI camera operators and stated that any qualified OGI camera operator should be able to conduct an audit on another camera operator. Other commenters (0808-API, 0831-AXPC) requested that EPA clarify that the audits may be performed by the OGI camera operator employer or a site owner or operator and there is no requirement for additional audits as the camera operator moves from one site to another or from employer to employer.

Several commenters (0750-Flogistix, 0814-IPAA, 0924-SBA, 0945/1373-JOFA) remarked that the performance verification requirements are particularly complicated and burdensome for small facilities, such as small oil and gas producers. Two commenters (0814-IPAA, 0945/1373-JOFA) stated that the proposed requirements would cause many small businesses to close because they cannot meet the financial, time, staffing, data storage or management obligations of the proposed requirements. Another commenter (0924-SBA) stated that, as proposed, these requirements would “practically preclude sole proprietors or businesses with a small number of employees because of the numerous requirements that require two people to do the job of one during initial training and quarterly auditing”. The commenter added that proposed operational requirements will also significantly increase the time and burden of OGI site visits.

Response I-22-61: EPA disagrees that senior OGI camera operators should be exempt from performance audits. As commenters pointed out, even senior OGI camera operators may perform poorly; as such it is important that the performance of all OGI camera operators be audited regularly to ensure that all OGI camera operators, even senior OGI camera operators, maintain the ability to see leaks. This is similar to how EPA Method 9 observers must be recertified every six months, regardless of how long the observer has been conducting EPA Method 9. A robust training and auditing program is necessary to ensure operators can see leaks that are present.

If a senior OGI camera operator performs poorly during comparative monitoring of an auditee, the owner or operator should consider whether it is appropriate for the senior OGI camera operator to continue to conduct senior OGI camera operator duties and the appropriate next steps based upon the specifics of the situation. Such next steps could include conducting a performance audit of the senior OGI camera operator, retraining the senior OGI camera operator,

or noting whether there were extenuating circumstances for the performance. The auditee would pass the audit if the auditee found more leaks than the senior OGI camera operator. EPA disagrees that Appendix K should provide that any leaks identified during video review by the senior OGI camera operator as being allegedly missed are not considered leaks for regulatory compliance purposes; the owner or operator must decide in each individual case whether a leak exists.

EPA recognizes that OGI camera operators that miss leaks during a performance audit need to be retrained following the audit and may not be available during a scheduled LDAR survey. EPA maintains that it is important that the OGI camera operators performing surveys can find leaks that are present and an OGI camera operator who fails an audit may not be able to find leaks that are present.

Audits of OGI camera operators must be performed by a senior OGI camera operator; OGI camera operators who are not senior OGI camera operators do not have the level of experience necessary to oversee other OGI camera operators. Additionally, the owner or operator of a site cannot perform this function, as the owner or operator may not have any experience with an OGI camera. However, EPA agrees that if an OGI camera operator changes employers, as long as the OGI camera operator maintains adequate records of past training and auditing, there is no need to repeat the training and auditing requirements.

In response to comments received on the November 2021 Proposal, EPA updated the OGI camera operator audit requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>40</sup>

In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>41</sup>

See additional responses related to the final requirements for OGI camera operator audit requirements in Volume II, Chapter 22, Section 22.4.6.

#### 22.5.7.2 Performance Audit Frequency

Comment: Several commenters (0561-TRICORD, 0718-Tora, 0750-Flogistix, 0808-API, 0814-IPAA, 0831-AXPC, 0916-AOGA) opposed the quarterly frequency of the audits. Commenters (0561-TRICORD, 0718-Tora, 0814-IPAA) remarked that quarterly audits are unreasonable, costly, and overly burdensome. Some commenters (0463-Southern Ute, 0786-Enerplus, 0817-GPA) pointed out the audits require two operators every quarter, one being a senior OGI camera operator, which would impose additional overhead at significant cost. Many commenters (0561-TRICORD, 0599-MSD, 0718-Tora, 0749-PAW, 0808-API, 0831-AXPC, 0916-AOGA) recommended an annual audit or, alternatively, biennial audits. One commenter (0718-Tora)

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<sup>40</sup> See 87 FR 74837-74838 (December 6, 2022).

<sup>41</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).



noted that an annual audit would align with typical performance review frequencies. Another commenter (0808-API) urged that annual audits would reduce the demand on senior OGI camera operator time, allowing more time for senior OGI camera operators to do monitoring and training, while a commenter (0599-MSD) similarly raised concerns about quarterly audits placing additional obligations on the limited number of qualified camera operators. An additional commenter (0782-BHE) also stated that performance audits should be conducted no more frequently than annually. One commenter (0561-TRICORD) recommended that EPA could begin by requiring quarterly audits but then decrease in frequency to semiannual if no problems are present and could return to a quarterly frequency if a leak is found to have been missed during a semiannual audit. The commenter also noted that leaks could occur after a viewing is performed, therefore, EPA could consider designating the frequency of audits by the number of leaks found (e.g., a facility conducting annual audits that found 5-10 leaks would return to quarterly performance audits, but a facility that only found 1-4 leaks would return to semiannual audits).

Response I-22-62: In response to comments received on the November 2021 Proposal, EPA updated the OGI camera operator audit requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>42</sup> See additional responses related to the final requirements for OGI camera operator audit requirements in Volume II, Chapter 22, Section 22.4.6.

#### 22.5.7.3 Performance Audit Length

Comment: Commenters (0599-MSD, 0749-PAW, 0808-API, 0831-AXPC, 0916-AOGA) asserted that four hours is an excessive length for the performance audit; most commenters recommended one hour as adequate to assess if the auditee is following procedures and monitoring correctly. One commenter (0599-MSD) stated the 4-hour survey is arbitrary and may not be applicable if the site being audited is a small compressor station or a well pad where the original survey would not meet that time requirement. Another commenter (0808-API) stated that a 4-hour requirement is not a reasonable use of resources, stating that the proposed requirements would tie up an OGI camera operator and auditor for more than a day and a third person (taking the video) for more than half a day. The commenter requested that if the requirement is maintained, it should allow for a senior operator to simply observe the auditee and not have to record a video, to eliminate the need for a third person.

Response I-22-63: EPA notes that if it takes less time to survey a site than the length of time required for a performance audit, surveys of multiple sites can be used to achieve the required audit time. Additionally, EPA is clarifying that we did not propose, nor are we finalizing, a requirement for a third person to video the audit, and as such, there is no need for a third person to be involved in a performance audit.

In response to comments received on the November 2021 Proposal, EPA updated the OGI camera operator audit requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related

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<sup>42</sup> See 87 FR 74837-74838 (December 6, 2022).

to operator training.<sup>43</sup> See additional responses related to the final requirements for OGI camera operator audit requirements in Volume II, Chapter 22, Section 22.4.6.

#### 22.5.7.4 Performance Audit Approaches

Comment: One commenter (0561-TRICORD) specifically questioned the proposed performance audit by video review. The commenter contended that a 4-hour imaging video is not an effective audit technique and suggested removing this as an audit option or significantly reducing the number of hours of video to be reviewed. Alternatively, video reviews could be conducted for three quarters, with a site audit conducted annually. Another commenter (0599-MSD) stated that Appendix K shows a lack of understanding for how OGI camera programs and surveys work in real life, because reviewing video footage collected by another surveyor is useless from an auditing standpoint. The commenter stated that video review forces the auditor to only utilize data collected via the methods and procedures of the surveyor, not utilizing their own skills to compare results. The commenter additionally noted that the video clips captured via OGI cameras are generally poor when compared to the way that the live screen image appears through the viewfinder or LCD screen during the survey.

Some commenters (0808-API, 0831-AXPC) supported alternative audit approaches, since there will be many variants in monitoring organizations, monitoring schedules, senior OGI camera operator availability, and facilities. The commenters requested that EPA require that the performance audit methodologies be included in the monitoring plan and that the two currently proposed approaches in sections 10.4.1 and 10.4.2 be cited as examples. One of the commenters (0808-API) further suggested other alternative approaches, including visual observation by a senior OGI camera operator (as opposed to their reviewing a video), observation by a monitoring supervisor, or review of results from monitoring at a test facility.

Response I-22-64: EPA provided an option to conduct audits by video review to assist small companies who may not have the resources to schedule comparative monitoring of each OGI camera operator. We think this is a viable alternative to comparative monitoring, as a senior OGI camera operator can watch the video to determine if the OGI camera operator looked at the scene for an appropriate amount of time and from multiple angles, whether the background was considered, and whether interferences were dealt with appropriately.

EPA disagrees that owners and operators should be allowed to create their own auditing procedures in the monitoring plan, as it could lead to auditing techniques that do not appropriately monitor the capabilities of the OGI camera operator. While the techniques suggested by the commenter will provide information on the OGI camera operator's ability, EPA disagrees that the suggested techniques provide adequate information for an audit. For example, knowing that an OGI camera operator can perform well at a test facility is good information about the operator's ability, but it is not as good as knowing that the OGI camera operator can see leaks under actual field conditions. Likewise, visually observing someone conducting a survey will provide information on aspects of survey technique like dwell time and angles, but it will not provide information on whether the OGI camera operator missed any leaks. Therefore,

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<sup>43</sup> See 87 FR 74837-74838 (December 6, 2022).

EPA is retaining, as proposed, two options for OGI camera operator audits, comparative monitoring and video review.

In response to comments received on the November 2021 Proposal, EPA updated the OGI camera operator audit requirements for Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.2 of the December 2022 Supplemental Proposal related to operator training.<sup>44</sup> See additional responses related to the final requirements for OGI camera operator audit requirements in Volume II, Chapter 22, Section 22.4.6.

#### 22.5.7.5 Performance Audit Repair Requirements

Comment: One commenter (0718-Tora) stated that since comparative monitoring would not be performed simultaneously, it would be possible for a leak to commence in between the auditee and senior OGI camera operator monitoring events. The commenter recommended that section 10.4.1 provide that the leak repair timeline for regulatory compliance purposes starts on the date that the leak allegedly missed by the trainee is found by the senior OGI camera operator.

Response I-22-65: Leak repair timelines are defined by the referencing subpart and are not defined in Appendix K. Generally, leak repair timelines are based upon the date that a leak is first found.

#### ***22.5.8 Senior OGI Camera Operators***

Comment: Various commenters raised issues with the burden associated with the senior OGI camera operator requirements and expressed concern over a limited supply of qualified senior OGI camera operators. Commenters (0599-MSA, 0782-BHE, 0924-SBA) stated that the current definition of senior OGI camera operator coupled with their involvement in training and auditing requirements of other OGI operators would greatly limit the availability of qualified senior OGI camera operators to conduct audit surveys. Further, this limited supply of operators would result in increased costs, logistical challenges, potential non-compliance due to capacity issues, and backsliding to older technologies such as EPA Method 21. One commenter (0782-BHE) further argued that the criteria for training, auditing, and annual survey requirements outlined in section 10.5 of Appendix K appears to rely on research done at a Colorado State University research site and does not account for real-world operating conditions. Another commenter (0463-Southern Ute) found the definition of senior OGI camera operator overly stringent, which would significantly affect the ability of owners and operators to dedicate qualified staff for OGI surveys, possibly necessitating the use of external third-party contractors resulting in increased costs and delay in leak repairs. Commenters (0808-API, 0831-AXPC) outlined all the senior OGI camera operator requirements from sections 3.0, 10.2.1, and 10.2.2 of Appendix K and noted that the overall burden these requirements would place on senior OGI camera operators would result in a very limited supply of senior OGI camera operators and very limited time available for conducting audit surveys. The commenters further argued that the implementation of OGI as an alternative to EPA Method 21 can only succeed if the supply of senior OGI camera operators exceeds the demand. Another commenter (0743-WEA) noted that requiring 50 surveys be done under a senior OGI camera operator's supervision, 10 surveys to be observed by a senior OGI camera operator, and 40 surveys to be verified by a senior OGI camera operator does not

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<sup>44</sup> See 87 FR 74837-74838 (December 6, 2022).

adequately account for the staffing limitations already faced by several operators. A commenter (0817-GPA) noted that the 500-survey qualification requirement would rule out the use of in-house personnel at compressor stations which would cause operators to rely on a relatively limited number of contractors, increasing rates due to the increased demand and relatively small supply of qualified OGI camera operators and senior OGI camera operators.

Response I-22-66: In response to comments received on the November 2021 Proposal, EPA updated the requirements for senior OGI camera operators in Appendix K in the December 2022 Supplemental Proposal. See discussion in section VI.B.3 of the December 2022 Supplemental Proposal related to senior OGI camera operators.<sup>45</sup>

In response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>46</sup>

See additional responses related to the final requirements for senior OGI camera operators in Volume II, Chapter 22, Section 22.4.7.

Comment: Commenters (0808-API, 0831-AXPC) noted that some OGI camera operators are certified thermographers. The thermographic certification requirements for a Level 2 thermographer parallel the initial and refresher OGI training requirements that would apply under Appendix K. The commenters recommended that certified thermographers be considered as senior OGI camera operators and that they be exempted from the initial training requirements in proposed sections 10.1 through 10.3. One commenter (0808-API) further recommended adding a definition of a certified thermographer as follows: *Certified Thermographer for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.*

Response I-22-67: EPA disagrees that there is a need to add this requirement to Appendix K. If the established training for certified thermography program parallels the training requirements in Appendix K, the owner or operator will be able to use that documentation to show that the senior OGI camera operator meets the requirements outlined in Appendix K.

#### ***22.5.9 Miscellaneous Training Comments***

Comment: One commenter (0463-Southern Ute) requested that OGI camera operator experience be documented based on a calendar year rather than a rolling 12-month period to reduce administrative burden. A different commenter (0808-API) recommended that 12-month be clarified to mean the 365-calendar days prior to the day of the activity.

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<sup>45</sup> See 87 FR 74838-74839 (December 6, 2022).

<sup>46</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

Response I-22-68: In the December 2022 Supplemental Proposal, EPA clarified that previous 12 months means the 365-calendar days prior to the day of the activity that requires a senior OGI camera operator.

Comment: A few commenters had recommendations on developing training programs that could be implemented by all operators. One commenter (0959-Colt) suggested that EPA consider developing an OGI Surveyors Certification Program with corresponding initial and annual training and field exams. Successful trainees would then use their certificate of completion as proof of competency and certification. Commenters (0814-IPAA, 0945/1373-JOFA) added that EPA should consider providing short online OGI training seminars for experienced OGI operators to enhance their skills with latest tips and techniques.

Response I-22-69: At this time, EPA is not developing OGI training programs. OGI camera operators can develop their own program or to attend programs developed by third-party providers.

Comment: One commenter (0911-NDPC) agreed with the requirement for training but requested flexibility on whether the training is manufacturer, third-party, company-specific, or EPA content.

Response I-22-70: EPA notes that it has not specified who must perform the training. The training can be performed by anyone qualified to instruct operators in optical gas imaging fundamentals and applications. Such entities may include camera manufacturers, company personnel, or third-party vendors.

Comment: A commenter (0808-API) recommended that the following sentence be deleted from section 10.1: “If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.” The commenter stated that any company contracting for OGI monitoring services has a responsibility to assure that those services meet any applicable requirements. The commenter further noted that a training plan is not more critical than any of the other requirements of Appendix K and questions how individual facilities would “ensure” compliance with the training plan requirements.

Response I-22-71: EPA disagrees with the comment. The training plan is crucial to the success of an OGI operator’s ability to find leaks. If an owner or operator chooses to use another company to perform monitoring services, it should request documentation from that company that the operator performing the services were trained in accordance with the requirements of Appendix K.

## **22.6 Operating Envelope**

### ***22.6.1 Party Responsible for Envelope Development***

Comment: Commenters (0463-Southern Ute, 0719-Opgal, 0782-BHE, 0808-API, 0814-IPAA, 0831-AXPC, 0911-NDPC, 0945/1373-JOFA, 1458-IES) requested clarification on who is responsible for developing OGI camera operating envelopes. Some commenters (0463-Southern Ute, 1458-IES) suggested that EPA clearly assign these responsibilities to the camera

manufacturers and stated that these requirements can even be set apart in their own section. One commenter (0945/1373-JOFA) recommended that EPA place any requirements for testing, laboratory, or funding on the manufacturers of OGI cameras as “certifications prior to point of sale” of the equipment, with another commenter (0911-NDPC) requesting EPA to issue certifications to companies whose OGI technology complies with this protocol, like the certification provided under NSPS OOOOa. Yet another commenter (0954-FLIR) suggested that third-party accreditation conducted by an independent camera manufacturer or a third-party, like National Physical Laboratory, could define an operating envelope and ensure compliance with Appendix K and allow operators to avoid an independent assessment. Still another commenter (0743-WEA) suggested that EPA allow for a generalized operating envelope to be developed for an entire operational area and note where an individual operating envelope might be necessary for a specific type of component or situation.

Response I-22-72: EPA notes that it did not issue any certifications for OGI cameras under NSPS OOOOa. Certain camera manufacturers had models of their OGI cameras tested independently and provided certifications that the cameras met the requirements outlined in NSPS OOOOa, but EPA was not involved in this process. Similarly, EPA does not intend to certify OGI cameras for Appendix K.

Section 8.0 was updated in the December 2022 Supplemental Proposal to specify that owners, operators, camera manufacturers or third parties may develop operating envelopes for OGI cameras. We note that operating envelopes must be developed initially, prior to conducting surveys with the OGI camera, but that the operating envelope may be updated or expanded at any time, even on a site-specific basis, following the procedures in section 8.0. See discussion in section VI.C of the December 2022 Supplemental Proposal related to operating envelopes.<sup>47</sup> Additionally, see discussion in section XIV.B.3 of the preamble to the final rule which details EPA’s final standards related to daily field checks in lieu of an operating envelope.

Comment: One commenter (0945/1373-JOFA) stated that the state of Michigan had indicated limited interest in working together to meet Appendix K performance verification and on-going annual auditing because of a “conflict of interest.” This leads the commenter to question what EPA proposes to allow as an equal playing field for small businesses with regard to section 8.0 of Appendix K.

Response I-22-73: Section 8.0 was updated in the December 2022 Supplemental Proposal to specify that owners, operators, camera manufacturers or third parties may develop operating envelopes for OGI cameras. This should relieve some of the burden for individual OGI operators. See discussion in section VI.C of the December 2022 Supplemental Proposal related to operating envelopes.<sup>48</sup>

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<sup>47</sup> See 87 FR 74839-74842 (December 6, 2022).

<sup>48</sup> See 87 FR 74839-74842 (December 6, 2022).

### ***22.6.2 Operating Envelopes for Camera Models***

Comment: Commenters (0561-TRICORD, 0604-Providence, 0808-API) requested that the language in Appendix K be changed to designate operating envelope development is specific to camera model and configuration rather than to “each OGI camera” as proposed.

Response I-22-74: Section 8.3.1 of Appendix K was updated to specify that operating envelopes are developed for each model of OGI camera and each configuration.

### ***22.6.3 Configuration Concerns***

Comment: Two commenters (0954-FLIR and 0604-Providence) challenged the necessity of developing an operating envelope for every camera configuration. One commenter (0954-FLIR) argued that if configurations are similar, but one is more challenging than the other, developing an operating envelope for the more challenging configuration should satisfy both configurations; for example, developing an envelope for 10 meters would satisfy the 10-meter configuration and a 5-meter configuration. The commenter also challenged that there exist too many different configurations for OGI cameras and being asked to develop an operating envelope for each is unreasonable. The commenter stated that testing every color palette, manual level, and span mode would create too many configurations to test.

Similarly, another commenter (0808-API) believed that certain variables which could constitute a different configuration do not impact the detection ability of the OGI camera and therefore should not be considered when determining testable configurations. The commenter stated as an example that whether a camera is hand-held verses tripod-mounted verses drone-mounted is an irrelevant variable so long as the other conditions of the configuration are consistent.

Response I-22-75: In the December 2022 Supplemental Proposal, section 8.3.2 of Appendix K was revised to indicate that operating envelopes needed to be developed for any camera configuration that could impact the detection limit. EPA cannot provide a complete list of configurations that will affect the detection limit because each OGI camera model is different. The owner or operator should work in concert with the OGI camera manufacturer to determine which configurations will impact detection limits.

EPA notes that the distance example provided by the commenter is not a camera configuration, but an operating envelope parameter. While in a camera configuration, at a set delta-T and wind speed, the entity developing an operating envelope should determine the distance from which an OGI leak is visible.

See additional responses related to the final requirements for developing operating envelopes for OGI camera configurations in Volume II, Chapter 22, Section 22.5.3.

### ***22.6.4 Methane and Butane***

Comment: Several commenters (0604-Providence, 0782-BHE, 0954-FLIR) stated that the requirement to develop an operating envelope for both methane and butane is unnecessary because an operator can use documented response factors to develop the operating envelope for

one gas once an operating envelope has been developed for the other gas. The commenters suggested that an operating envelope should only need to be developed for methane as it has the lower response factor, compared to butane.

Another commenter (0808-API) requested flexibility in the requirement to test both methane and butane to develop the operating envelope. The commenter argued that in NSPS OOOOa, EPA currently requires that a camera's minimum detection be obtained using a methane/propane mixture. The commenter therefore requested that Appendix K allow for the use of either approach (methane and butane separately or a methane/butane mixture) to be acceptable for determining the operating envelope in Appendix K.

Response I-22-76: EPA notes that the development of operating envelopes is likely to be a one-time requirement for each camera model, although owners and operators do have the ability to adjust these envelopes at any time by doing further testing. Therefore, we do not consider it onerous to test for both butane and methane. While methane is less sensitive to detection for OGI cameras that operate in the 3.2-3.4 micron range, we have no empirical evidence to prove that the operating envelope for butane will always be better than the operating envelope for methane. Therefore, in the final rule EPA is maintaining the requirement to test both methane and either butane or propane during development of the operating envelope.

Additionally, in Appendix K, the gas release rates for developing the operating envelope are based on pure gases, not a mixture. Because Appendix K applies more broadly than NSPS OOOOa, it is important to verify the conditions under which an OGI camera can be used to determine leaks of methane and VOC individually, to ensure that leaks of both methane and VOC are able to be determined and that the inability to detect one compound is not masked by the ability to detect the other. Therefore, we are not adjusting the operating envelope requirement to allow a mixture of methane and butane.

#### ***22.6.5 Temperature-Controlled Background***

Comment: One commenter (0570-Konica Minolta) expressed concern over the requirement to use a temperature-controlled background encompassing approximately 50% of the field of view for the development of an acceptable operating envelope. The commenter contended that based on that requirement, if the camera was operated from a long distance, the temperature-controlled background size would need to be unreasonably large to fulfill the requirement. The commenter provided the following example: when the angle of view of the OGI camera is 24 degrees and the distance is 65 feet, then a 13-foot by 10-foot temperature-controlled background will be required.

Response I-22-77: EPA acknowledges the commenter's concern. In general, leak surveys conducted with Appendix K should not be conducted from far distances, due to the need to view components from multiple angles and the tight grouping of components in the types of units where Appendix K will be applied. OGI camera operators should optimize camera optics when surveying from a distance so that the component(s) being observed fills a large portion of the field of view; if this is done, the temperature-controlled background should not need to be unusually large. If an OGI camera operator needs to increase distance beyond the distance of the standard operating envelope to occasionally view components, EPA has updated Appendix K to



add section 8.7, which allows expansion of the operating envelope to determine a daily viewing distance under site-specific conditions.

While EPA acknowledges the commenter's concern, no solutions were offered by the commenter on how this issue could be resolved while maintaining a controlled background such that the OGI camera's span remains steady. If an owner or operator has an alternative to this requirement for use in developing operating envelopes, the owner or operator may request an alternative test method. If appropriate, Appendix K may be amended in a future rulemaking to incorporate approved alternatives.

## **22.7 Conducting OGI Surveys**

### ***22.7.1 Interferences***

Comment: One commenter (0463-Southern Ute) requested that determinations of whether a monitoring survey is of "acceptable quality", especially determinations regarding hot backgrounds, be left to the OGI camera operator's best judgment. The commenter noted that site-specific conditions may restrict a camera operator to a limited number of observation locations due to safety considerations or physical access limitations, which may require a camera operator to survey components with a relatively hot background. The commenter further noted that leaks can still be identified in hot backgrounds with staff trained to operate the OGI camera. Another commenter (0599-MSD) stated that although interferences from atmospheric conditions such as fog, mist, rain, and solar glint may have an impact on an OGI camera operator's ability to detect leaks, they do not fully eliminate the OGI camera operator's ability to determine the presence and location of emission points. Consequently, OGI surveys should not be prohibited during such periods of non-ideal atmospheric conditions.

Response I-22-78: EPA has not restricted camera operators from performing OGI surveys in any conditions. In section 4.0 of Appendix K, we note that there are certain conditions that may impact the quality of a survey. We maintain that this is true and recommend that these conditions be avoided to the extent possible.

### ***22.7.2 Daily Verification Check***

Comment: A commenter (0719-Opgal) remarked on the requirement in section 9.1.3 of Appendix K, stating that there is no need to use a cylinder of gas for the daily verification check because a clear thermal focus on the palm of a hand demonstrates sensitive gas detection.

Response I-22-79: Section 9.1.3 of Appendix K requires that a monitoring plan include confirmation that the OGI camera produces a live IR image using a known emissions source, such as a butane lighter or a propane cylinder. The monitoring survey protocol requires confirmation of both an emission source and temperature. Although imaging sweat evaporation off the palm of a hand is a powerful sensitivity demonstration, butane lighters are easily obtained, and a demonstration of a specific gas emission is more applicable.

Comment: Commenters (0463-Southern Ute, 0750-Flogistix, 0782-BHE, 0814-IPAA, 0911-NDPC) remarked that the monitoring plan requirements for daily verification checks and video

recording were overly burdensome. One commenter (1391-INGAA) cited video recordkeeping requirements as onerous, due to requiring multiple storage cards to save and upload footage without clear benefit. Another commenter (0782-BHE) questioned whether EPA had accurately accounted for the burden of video recordings in its cost analysis.

Some commenters generally supported the daily initial verification check (0808-API, 0831-AXPC), however, commenters (0808-API, 0814-IPAA, 0816-Montrose) objected to the requirement in proposed section 9.1.4 of Appendix K to record a video of the camera imaging a butane lighter or other validation sources as overly burdensome, costly, and unnecessary. Commenters (0808-API, 0814-IPAA) stated that it is more than adequate to simply have confirmed that the camera sees the butane lighter image as part of confirming the entire set of daily instrument requirements. One commenter (0816-Montrose) requested that EPA instead reference the daily instrument check requirements outlined for the use of OGI in the AWP; the commenter urged that removing sections 9.1 through 9.1.5 would also eliminate potential confusion from having two different daily check/verification requirements that are associated with the same activity. The commenter further expressed confidence that the manufacturer's proven daily instrument check requirements are the superior approach because they can be modified to suit new equipment without the process of redefining regulations.

One commenter (0954-FLIR) stated that daily verification checks are unnecessary for certain types of camera equipment. Specifically, the commenter asserted that if the camera used in the survey is engineered with a cold filter built onto the detector, there is no need to confirm that the OGI camera produces a live image using a known emission source, provided the camera loads successfully without error. The commenter provided a general instrument check process that can be used to ensure the camera can detect the intended compounds with the same sensitivity as when originally manufactured, including: (1) making sure that the camera powers on; (2) making sure that the camera completes the cool-down process and produces a live infrared image; (3) making sure that the camera does not report any error messages on startup; (4) making sure that the camera focuses properly, and (5) making sure that the camera is able to engage High Sensitivity Mode. The commenter requested that EPA clarify the need to emit gas during the daily verification check if the camera is engineered such that the filter cannot be removed.

Finally, one commenter (1458-IES) stated EPA should revise section 9 of Appendix K to clearly define the daily operator camera verification check.

Response I-22-80: EPA agrees it is unnecessary to record the daily verification check, as there is no requirement to record the survey itself. In the December 2022 Supplemental Proposal, EPA revised section 9.1 of Appendix K to remove the requirement to record the daily verification check.

EPA disagrees that the daily verification check is not well defined. EPA also disagrees that the daily instrument check in the AWP should be referenced in Appendix K. The approach to conducting OGI surveys is different in the AWP and Appendix K. For surveys conducted using Appendix K, because the OGI camera operator will already have established operating envelopes, there is no need to create an obligation to perform a daily distance check. EPA does not believe that having different daily checks in the AWP and Appendix K will cause confusion because the AWP and Appendix K will not both be used during the same survey. Additionally, other requirements between the AWP and Appendix K are vastly different, and as such, there is

no need to conform the daily check between the AWP and Appendix K. Furthermore, because there is nothing in the daily verification check in section 9.1 of Appendix K that is OGI camera specific and this check is only aimed at ensuring that an OGI camera is functioning as expected, EPA does not anticipate a need to revise the daily verification check in the future to suit new equipment.

EPA notes that the alternative daily verification check outlined by the commenter is similar to the daily verification check in Appendix K. Appendix K does not specify engaging particular operating modes because Appendix K is written to be generic and not all OGI cameras have the same operating modes. Additionally, because Appendix K is written generically, it is prudent to include a check that the camera can image a known emission source. Butane lighters are easily obtained and emit very little gas, and as such EPA does not consider the requirement to image a butane lighter to be burdensome or environmentally detrimental, especially when compared to the environmental consequences of conducting surveys with an OGI camera that will not be able to detect large leaks.

### ***22.7.3 delta-T Monitoring***

#### **22.7.3.1 Continuous Monitoring of delta-T**

Comment: One commenter (0604-Providence) focused on the importance of continuous monitoring of delta-T, considering this to be the fundamental element of all OGI measurements. The commenter asserts that the most important changing condition during a survey will be delta-T and recommends that Appendix K prescribe a method for continuous monitoring of delta-T throughout each OGI monitoring survey. The commenter presented an example on how the maximum detection distance for a methane leak will change considerably based on delta-T if both the leak rate and wind speed are consistent. The commenter further contended that delta-T will change with changes in both background and ambient temperatures and should thereby be recorded continuously. The commenter proposed two options for continuously monitoring delta-T.

In the first option presented by the commenter, the operating envelope can presume a minimum delta-T. That minimum delta-T will determine a maximum distance (camera model, wind speed, and other factors held constant) which can be applied throughout the survey. The operator can then conduct the survey in that operating envelope by ensuring that the minimum delta-T is met for each component surveyed while staying within the maximum distance established in the operating envelope for that delta-T. In the second option presented by the commenter, the operating envelope can consider delta-T as a variable, allowing the operator to determine the maximum distance for each component throughout the survey. In other words, the maximum distance will not be a fixed number for the entire survey. Instead, it will be determined by the delta-T based on the background for each view of the component. Components with a higher delta-T can be surveyed from a farther distance, provided the operator can determine the delta-T for each component as part of the survey. The commenter noted that the first option is simpler to implement but more restrictive than option 2, while option 2 would require implementation of the delta-T determination for each component, which could be demanding. The commenter also submitted an Excel workbook of “Data for OGI operating envelope based on the proposed minimum emission rate for methane and butane”.

Response I-22-81: EPA agrees with the commenter that delta-T is a fundamental component of OGI monitoring. In order to provide flexibility to OGI camera operators and ensure an adequate delta-T exists during surveys, the operating envelope treats delta-T as a variable. During development of the operating envelope, delta-T is varied to determine the boundaries of wind speed and distance where a trained OGI camera operator can observe a leak at a specific delta-T condition.

Comment: One commenter (0719-Opgal) noted the importance of taking the process gas temperature measurement at the correct location. The commenter emphasized that the emission gas temperature measurement should be taken near the source in the OGI frame but not right at the source. The commenter further contends that the emitted gas temperature at the point of release can be colder due to the expansion process while the temperature of the emitted gas will equalize to the ambient temperature a few centimeters away from the point of release (source).

Response I-22-82: EPA agrees with the commenter. As noted in the definition of delta-T, it is an acceptable practice in the field to assume that the emitted process gas temperature is equal to the ambient air temperature. This is due to the fact that process gas will quickly equilibrate to the ambient temperature once released. However, the commenter is correct that this does not happen immediately at the release point.

Comment: One commenter (0599-MSD) stated that when surveying in high sensitivity mode (the primary mode of many camera operators), plume movement is much more important than large delta-Ts - and plume movement is always present in a gas leak scenario due to the high-pressure gas escaping to atmosphere. The commenter contended that proper training, experience, and general operating principles are much more important and aid in effectively finding leaks.

Response I-22-83: Appendix K is written for broad applicability; it is not intended to apply only to cameras with particular operating modes. Additionally, OGI camera operators generally use more than one mode when conducting surveys, switching to the most appropriate mode based on the site conditions.

EPA disagrees with the commenter that all leaks occur at high pressure, although plume movement is an important indication of a leak. EPA agrees that proper training, experience, and knowledge of operating principles are all important elements for developing an OGI camera operator's ability to locate leaks that exist; Appendix K includes requirements for training and experience due to the importance of these elements. However, delta-T is also a fundamental concept in OGI monitoring, and as such, EPA is retaining the requirement to monitor delta-T during OGI surveys.

#### 22.7.3.2 delta-T Check Function

Comment: A few commenters (0561-TRICORD, 0719-Opgal) expressed concern over the use of a built-in delta-T check feature of OGI cameras or the use of a background temperature reading as an effective way for the operator to ensure that an adequate delta-T is present for viewing emissions. One commenter (0561-TRICORD) argued that collecting a background reading would require a second person constantly in the field to check the background each time the camera operator moves, which would make all cameras without the delta-T function too

expensive to use. The other commenter (0719-Opgal) considered the built-in camera delta-T function as manufacturer/camera specific and recommended providing more guidance to OGI camera operators who would be using a background temperature reading to ensure an adequate delta-T is present. The first commenter (0561-TRICORD) provided an example by suggesting that the background temperature reading be taken on a known and universal temperature spot like the human body.

Response I-22-84: Section 9.2.2 of Appendix K outlines the requirement for a description of how the operator will ensure an adequate delta-T is present to view potential gaseous emissions. The use of the built-in delta-T check function of OGI cameras is mentioned as an example of one way of ensuring an adequate delta-T is present. Operators may use and document other ways of ensuring an adequate delta-T is present, including using a background temperature reading in the OGI camera field of view. EPA is not limiting the methods that an OGI camera operator can use to determine an adequate delta-T exists; however, due to the importance of delta-T in OGI monitoring, the OGI camera operator must have some method for determining that an adequate delta-T exists.

Comment: Commenters (0719-Opgal, 0782-BHE) raised concerns over delta-T checks being included in the daily OGI camera functionality check. One commenter (0719-Opgal) considered the delta-T check to be a scene check and recommended not having a requirement for a delta-T check function or thermometry in the OGI camera. The other commenter (0782-BHE) suggested that thermography checks are not required for camera performance assurances and is a separate function within the camera and recommended eliminating the requirement to assess delta-T from monitoring plans.

Response I-22-85: EPA disagrees with the commenters. EPA notes that checking the delta-T check function is only required if the delta-T check function will be used to monitor delta-T during the survey. EPA considers a check of the delta-T check function as appropriate, considering the importance of delta-T in OGI monitoring.

Appendix K does not require that an OGI camera have a delta-T check function. The OGI camera operator may monitor delta-T in ways other than a delta-T check function, as long as the method for determining the delta-T is included in the monitoring plan. EPA is retaining the requirement to describe how the delta-T will be assessed in the monitoring plan, as delta-T is a fundamental component of OGI monitoring.

Comment: One commenter (0599-MSD) stated there is only one way to monitor delta-T and one camera which can do it. The commenter further stated that to fulfill this proposed requirement, an OGI camera operator must continuously concentrate on viewing a calculated number on the screen instead of focusing on visually interpreting the screen images to find potential leaks. Extensive field testing using a method which focuses on extreme delta-T limitations has led to finding less leaks, which negates its perceived advantages.

Response I-22-86: EPA disagrees with the commenter that there is only one way to monitor delta-T. Appendix K provides examples of two ways to monitor delta-T (using a delta-T check function built into the features of the OGI camera or using a background temperature reading in

the OGI camera field of view), and we acknowledge that an OGI camera operator may have additional ways of determining the delta-T.

EPA disagrees that monitoring delta-T will require the OGI camera operator to focus on a calculated number instead of interpreting the screen images to find leaks. Because delta-T is a fundamental component of OGI monitoring, the OGI camera operator must first determine that an adequate delta-T exists in the scene. Once the OGI camera operator determines that an adequate delta-T exists, the OGI camera operator does need to continuously focus on the delta-T; instead, the OGI camera operator should dwell on the scene for the required amount of time to determine if a leak is present.

#### ***22.7.4 Maximum Viewing Distance***

Comment: One commenter (0561-TRICORD) objected to the proposed requirement in section 9.2.1 of Appendix K to determine the camera operator's maximum viewing distance from surveyed components based upon wind speed and expected delta-T. The commenter questioned how the expected delta-T would be determined since delta-T varies from component to component depending on the temperature of the background and temperature of the leaking gas. Another commenter (0599-MSD) concurred, stating that delta-T is highly variable even at a single facility, and it is not possible to have a single "expected delta T".

Response I-22-87: EPA agrees with the points made by the commenters and has revised Appendix K to remove this requirement, except where an OGI camera operator will be using section 8.7 of Appendix K to establish a maximum viewing distance using a daily field check.

#### ***22.7.5 Dwell Time***

##### ***22.7.5.1 Length of Dwell Time***

Comment: Some commenters (0463-Southern Ute, 0599-MSD, 0718-Tora, 0814-IPAA, 0916-AOGA, 0954-FLIR) stated that a 5 second required dwell time per component is unnecessary or too long and pointed to both operator experience and increased survey time and cost with no corresponding benefit as reasons for this stance. One commenter (073-WEA) noted that this dwell time is especially inappropriate in an upstream setting. Commenters (0743-WEA, 0749-PAW, 0924-SBA) stated that Appendix K's dwell time and required rest requirements would increase the time to complete a survey or its cost by 2 or 3 times. Commenters (0749-PAW, 0814-IPAA) argued that OGI monitoring is valuable because of its time savings, cost savings, and rapid leak detection characteristics and the Appendix K requirements would nullify these characteristics. Another commenter (0570-Konica) concurred that in practical use, it is often possible to identify the leak source in a shorter amount of time, even in a larger monitoring area, and the commenter was concerned the new requirement might hinder an OGI camera operator's efficiency. The commenter requested EPA review the dwell time conditions, considering the current usage of OGI camera and its performance.

Commenters (0743-WEA, 0749-PAW) maintained that dwell times can be highly variable and prescribing exact requirements is not feasible. Another commenter (0817-GPA) agreed, arguing that viewing components individually from at least two different angles for a total of ten seconds at a model site of 1,800 components would result in the survey time for a single facility being

five hours. The commenter warned that time spent on OGI monitoring will increase substantially when all additional factors of Appendix K (including an additional break time, calibration time, travel time, audit requirements, and increased frequency of monitoring) are considered. Two commenters (0808-API and 0814-IPAA) suggested the prescriptive dwell time is overly restrictive and rigid and dwell time should be left to the discretion of the operator. One of the commenters (0808-API) further argued that experienced operators know how much dwell time is appropriate for each situation and guidance is unnecessary. Other commenters (0599-MS, 0743-WEA, 0831-AXPC) pointed out that EPA has not provided any explanation for the dwell time requirement or that implementing this requirement would result in the identification of more leaks, reduction of more emissions, or improvement of OGI camera operator performance.

Once commenter (0743-WEA) believed the dwell time would end up having unintended negative consequences that are contrary to the Administration's objectives. The commenter is working to continuously improve facility designs, including adding automation, eliminating tanks where they are not necessary, and designing separation stages to capture as much gas as possible most efficiently. The commenter noted that many of these modern designs require the installation of additional components (valves, controllers, gauges, connectors), and by requiring facilities with many components to include extended dwell times for each component, EPA is inadvertently disincentivizing innovation in facility design and emissions mitigation. The commenter suggested that EPA clarify that the dwell time for multiple components can be completed concurrently.

One commenter (0816-Montrose) supported another commenter's (0954-FLIR) view that the dwell times proposed in section 9.4 are very arduous and contradict the reasoning for ensuring operators are trained, as detailed in section 10 of Appendix K. The commenter (0816-Montrose) further stated that experienced operators only need 3 seconds per scene to evaluate for leaks. This commenter stated the Texas Council on Environmental Quality recently agreed that a three second dwell time is acceptable. The commenter pointed out that requiring a minimum dwell time of 5 seconds and requiring operators to view components from a minimum of 2 angles would considerably increase survey times which could in turn make surveying more expensive. The commenter provided the following example: a technician following current industry standards and utilizing dwell times of 3 seconds per scene with multiple angles can finish a 7,000-component facility in an average time of 5.5 hours; by comparison, Appendix K would require 70,000 seconds or 19.4 hours of dwell time, which is estimated to increase survey cost from \$1,265 to over \$5,000. Another commenter (0599-MS) provided a different example: an average Pennsylvania well pad may include 2,500 fugitive components, which can be effectively imaged using NSPS OOOOa procedures in approximately 1.5 hours; by comparison, Appendix K would require seven hours to complete the same survey (not counting any additional time for initial procedures or leak repair efforts). The commenter recommended removing the dwell time requirement.

Other commenters also supported the concept of dwell time on a scene basis. One commenter (0782-BHE) stated that if the dwell time provision or any part is retained the requirement should be scene-based and not component based. Other commenters (0816-Montrose, 0954-FLIR) recommended that dwell time be on a scene basis, not a per component basis, and it should account for the level of operator as a factor. Another commenter (0599-MS) stated the burdensome nature of requirements related to "dwell time" cannot be overstated; common

practice is to find a single leaking component within a cluster of components and then locate the actual egress point by simply moving closer at various points within the area until the leak is identified. A different commenter (0561-Tricord) also stated that imaging on a component-by-component basis is impractical and takes more time than EPA Method 21. The commenter stated that the 5-second dwell time ought to apply to all the components in the camera's field of view.

Response I-22-88: In the December 2022 Supplemental Proposal, section 9.4.1 of Appendix K was amended to reflect a 2 second dwell time per component in the field of view instead of 5 seconds per component in the field of view. See discussion in section VI.B.4. and VI.C. of the December 2022 Supplemental Proposal.<sup>49</sup>

Additionally, in response to comments received on the December 2022 Supplemental Proposal, EPA has continued to refine the dwell time requirements in Appendix K. See discussion in section XIV.B.1 of the preamble to the final rule, which details EPA's final standards related to dwell time.

Also, in response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>50</sup>

#### 22.7.5.2 Table 14-1

Comment: One commenter (0817-GPA) stated that section 9.4 of Appendix K requires camera operators to survey each component for five seconds per viewing angle, providing an example of five components requiring 25 seconds of dwell time; Table 14-1, however, states that five components would be monitored in 10–20 seconds, depending upon the monitoring area, which is much more reasonable. The commenter stated that in view of this apparent inconsistency, the EPA should clarify the dwell time it is proposing and explain the basis for the proposed dwell time so stakeholders may assess the rationale, as no explanation is provided in the proposal.

Response I-22-89: In the December 2022 Supplemental Proposal, section 9.4.1 of Appendix K was amended to reflect a 2 second dwell time per component in the field of view instead of 5 seconds per component in the field of view. See discussion and rationale in section VI.B.4. and VI.C. of the December 2022 Supplemental Proposal.<sup>51</sup>

Additionally, in response to comments received on the December 2022 Supplemental Proposal, EPA has continued to refine the dwell time requirements in Appendix K. See discussion in section XIV.B.1 of the preamble to the final rule, which details EPA's final standards related to dwell time.

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<sup>49</sup> See 87 FR 74839-74841 (December 6, 2022).

<sup>50</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

<sup>51</sup> See 87 FR 74839-74841 (December 6, 2022).



Comment: One commenter (0604-Providence) suggested that the monitoring area requirement for the field of view be removed, and dwell time be determined by the number of components alone. The commenter pointed out that requiring a specific viewing area would be overly restrictive and does not account for practical considerations like the type of camera lens used or the complexity of the scene. The commenter stated the requirements for the operating envelope would likely guide operators to establish suitable distances from components, thus rendering the required viewing areas to be redundant and possibly in conflict with the operating envelope. The commenter further noted the intention of Table 14-1 is to increase dwell time when the scene is more complex and/or contains more components and recommend that EPA consider simply specifying dwell time based on the number of components regardless of the size of the monitoring area. The commenter stated that this could be further refined by defining the scene as “simple” or “complex” with dwell time increased for “complex” scenes; example of a simple scene may include a tank with a minimum number of pipes while an example of a complex scene may include a highly congested area with many pipes and components.

Another commenter (0782-BHE) noted that EPA has not defined the term “monitoring area” and as written, the following footnote in Table 14-1 may arbitrarily restrict the viewing distance from a source to approximately 10.5 feet using a 25-millimeter lens. The commenter argued this may eliminate the distinct OGI advantages for screening leaks from elevated sources or vents irrespective of the number of components in the scene. The commenter suggested test data and the basis for this restriction of the largest monitoring area to less than one square meter irrespective of the number of components in the subsection may be lacking and unfounded. The commenter further noted the term subsection is not defined and confusing in this context.

Response I-22-90: In the December 2022 Supplemental Proposal, section 9.4.1 of Appendix K was amended to reflect a 2 second dwell time per component in the field of view instead of 5 seconds per component in the field of view. See discussion and rationale in section VI.B.4. and VI.C. of the December 2022 Supplemental Proposal.<sup>52</sup>

Additionally, in response to comments received on the December 2022 Supplemental Proposal, EPA has continued to refine the dwell time requirements in Appendix K. See discussion in section XIV.B.1 of the preamble to the final rule, which details EPA’s final standards related to dwell time.

Comment: One commenter (0604-Providence) found Table 14-1 to be unrealistic in its definition of monitoring areas. The commenter believed that the table outlines unrealistic scenarios where the number of components to the specified areas would never occur in real world environments, thus rendering the table unusable. Other commenters (0782-BHE, 0814-IPAA, 0911-NDPC) disputed the necessity of Table 14-1, arguing that it is arbitrary, does not have a credible source attributed to it, and therefore seems inappropriate to require. One commenter (0782-BHE) stated that if the table is retained, this table and the one paragraph of discussion that follows it would likely be more suitable for inclusion and expanded upon in section 9 of Appendix K.

Another commenter (0718-Tora) argued that Table 14-1 establishes an effective maximum viewing area of 1 square meter, which would make OGI monitoring impossible, and requiring

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<sup>52</sup> See 87 FR 74839-74841 (December 6, 2022).

operators to consult Table 14-1 during surveying would be technically infeasible. The commenter critiqued the depth of components requirement for the use of Table 14-1 to be arbitrary and unnecessary and possibly unsafe since it requires operators to have to navigate complex component systems to establish the appropriate depth.

One commenter (0782-BHE) recommended the elimination of Table 14-1 as it presents requirements that will be an unenforceable and inefficient burden on the leak survey process. The commenter contended that Table 14.1 is not referenced or discussed elsewhere in Appendix K and contains unintended OGI restrictions for screening leaks. A second commenter (0599-MSD) supported elimination of Table 14.1 because the requirements are inconsistent with what experienced camera operators would do and not technically feasible due to the requirement to continuously measure distance and count components to determine the applicability of the table. Another commenter (0561-TRICORD) recommended EPA change the title of Section 14 because this protocol does not include any Diagrams of Flow Charts.

Response I-22-91: In the December 2022 Supplemental Proposal, section 9.4.1 of Appendix K was amended to reflect a 2 second dwell time per component in the field of view instead of 5 seconds per component in the field of view. See discussion and rationale in section VI.B.4. and VI.C. of the December 2022 Supplemental Proposal.<sup>53</sup>

Additionally, in response to comments received on the December 2022 Supplemental Proposal, EPA has continued to refine the dwell time requirements in Appendix K. See discussion in section XIV.B.1 of the preamble to the final rule, which details EPA's final standards related to dwell time.

#### 22.7.5.3 Other Dwell Time Comments

Comment: One commenter (0599-MSD) stated that holding the camera "steady" is often a poor practice for finding leaks with an OGI camera, particularly in high sensitivity mode. It is often much better to "pan" or slowly move the camera across a scene, to avoid screen flickering and aid in seeing plume movement.

Response I-22-92: EPA disagrees with the commenter. While initially panning a scene can provide detection of certain leaks quickly, to see movement on the screen and ensure all leaks are found, the scene on the screen needs to be held steady, even in an enhanced or high sensitivity mode.

#### **22.7.6 Rest Breaks**

Comment: Several commentors (0599-MSD, 0718-Tora, 0749-PAW, 0750-Flogistix, 0782-BHE, 0808-API, 0814-IPAA, 0816-Montrose, 0817-GPA, 0954-FLIR, 0945/1373-JOFA) believed a prescribed break schedule is unnecessary and should not be defined in Appendix K. These commenters pointed out that OGI camera operators do not look through their cameras for 20-minute stretches and therefore do not require section 9.5 to outline breaks for eye fatigue. Commenters stated that rest breaks should be left up to the OGI camera operator's discretion. One commenter (0599-MSD) noted that operator fatigue is unique to each OGI camera operator

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<sup>53</sup> See 87 FR 74839-74841 (December 6, 2022).

and survey situation. The commenter stated that generally, the OGI camera operator is not continuously surveying from a fixed location for an extended period, thus the OGI camera operator has frequent small survey breaks moving from location to location. One commenter (0831-AXPC) stated that there is no generic or efficient approach for avoiding operator fatigue that would not interfere with the execution of the survey and recommend that all but the first sentence of section 9.5 be deleted.

One commentor (0749-PAW) argued that proper field training, which is required in Appendix K, would already include discussions about operator fatigue and rest break frequency. Other commentors (0793-PBPA, 0945/1373-JOFA) stated experienced camera operators know when to take breaks without Appendix K guidance, and the decision to take a break should be left to the OGI camera operator, with one commenter (0793-PBPA) pointing out that a 20-minute break requirement is arbitrary. A third commenter (0814-IPAA) noted that prescribed rest breaks are unjustified and insulting to small businesses and individuals that purchased OGI cameras, suggesting that senior level camera operators are not capable of defining specific rest intervals based on experience, training, and physical conditioning and implying that all OGI camera operators have similar operating limitations. Two commentors (0749-PAW, 0782-BHE) stated that requiring frequent breaks would add to the time needed to perform surveys, leading to greater costs.

Two commenters (0814-IPAA, 0945/1373-JOFA) further questioned how EPA is proposing to level the playing field for sole proprietorship companies that cannot meet the proposed requirement of having 2 camera operators, as proposed in Section 9.5, when engaged in continuous monitoring. The commenters stated this requirement is highly discriminatory and would likely prohibit senior level certified small business camera operators from conducting large facility inspections. Another commenter (0793-PBPA) noted that having 2 camera operators for a survey is not always feasible and will be cost prohibitive for small operators.

Two commenters (0561-TRICORD, 1391-INGAA) argued that 20 minutes between breaks is too short of a time window. One commenter (0561-TRICORD) recommended a 30-minute interval instead of 20 minutes. Another commenter (0814-IPAA) stated EPA does not define what constitutes a "break." The commenter noted that on most occasions, OGI camera operators survey for leaks at 1-3 minutes intervals from a fixed location prior to moving to another fixed location to scan the same components from a second angle; the commenter questioned whether this constitutes a break.

Response I-22-93: In the December 2022 Supplemental Proposal, EPA revised section 9.5 of Appendix K to increase the surveying interval prior to taking a break to 30 minutes. See discussion in section VI.B.5 of the December 2022 Supplemental Proposal.<sup>54</sup>

EPA notes that section 9.5 allows performing other survey related tasks besides "actively imaging components" as a break, such as documenting leaks found. This would also allow operators to stay productive during their break and would not impede the overall survey length.

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<sup>54</sup> See 87 FR 74839 (December 6, 2022).

EPA disagrees that a mandated rest break is unnecessary. The language for rest breaks that was put into the November 2021 Proposal was derived from EPA Method 9, which is another visual observation method. EPA determined it was appropriate to add a similar requirement for Appendix K because both mental and eye fatigue are known issues that occur with prolonged viewing of components with an OGI camera. Such fatigue may be a safety hazard, and it may also prevent the OGI camera operator from finding leaks that are present.

EPA acknowledges natural breaks will occur at regular intervals when an OGI camera operator moves between process units or process levels and notes that rest breaks are only required if these natural breaks do not occur frequently enough such that the OGI camera operator is continuously surveying for more than 30 minutes. EPA encourages OGI camera operators to take longer or more frequent rest breaks as needed to reduce the incidence of fatigue.

### ***22.7.7 Monitoring Plans***

Comment: Commenters (0718-Tora, 0782-BHE, 0808-API, 0831-AXPC) questioned the requirements for each “site” to prepare monitoring plans and procedures. One commenter (0782-BHE) noted that requiring individual site monitoring plans is overly burdensome and encouraged EPA to permit operators to develop a single monitoring plan for components at multiple locations. Similarly, commenters (0718-Tora, 0808-API, 0831-AXPC) requested that the requirements not be based on a site or be site-specific. One commenter (0808-API) stated that EPA should clarify that a copy of the plan is not required to be maintained at every site; the commenter pointed out that a monitoring plan is developed centrally and would be available electronically to operators when monitoring a specific site.

Response I-22-94: In the December 2022 Supplemental Proposal, EPA added clarification that a monitoring plan can encompass multiple sites, as long as the relevant information for each site is included in the monitoring plan. EPA also updated other wording in section 9 to refer to the monitoring plan instead of to the site.

EPA notes that Appendix K does not require that records be kept at a particular site; instead, Appendix K states that these records must be retained and easily accessible.

Comment: One commenter (0782-BHE) requested EPA eliminate the monitoring plan reference and requirement from section 9.8 of Appendix K or reword it to state that the survey should follow the monitoring plan QA/QC procedures in conformance with section 11.0.

Response I-22-95: EPA disagrees with the commenter. Section 9.8 is part of what is required in a monitoring plan, so the reference to the monitoring plan cannot be removed from this requirement. Section 9.8 requires the monitoring plan to describe the QA/QC process that will be used to ensure valid monitoring data. EPA does not agree that there is a need to reword this requirement.

### ***22.7.8 Daily QA Videos***

Comment: Several commenters (0463-Southern Ute, 0561-TRICORD, 0599-MSD, 0604-Providence, 0782-BHE, 0808-API, 0814-IPAA, 0816-Montrose, 0817-GPA, 0831-AXPC,

0945/1373-JOFA, 0954-FLIR) specifically posed that the 5-minute quality assurance video required by the monitoring plan is an unnecessary burden and requested that EPA remove this requirement. Commenters (0599-MSD, 0808-API, 0954-FLIR) asserted the training, daily check, and audit requirements within the rule would ensure survey quality, making the QA video requirement unnecessary and redundant. One commenter (0750-Flogistix) remarked that the verification check requirements are too complicated and burdensome for small facilities, such as small oil and gas producers. A third commenter (0463-Southern Ute) noted that for many simple well sites, the QA video could take longer than the actual monitoring survey, and a simple confirmation that the requirements of section 9.1 are met should be sufficient.

Commenters (0808-API, 0831-AXPC) stated that is unclear how a video clip would show compliance with the procedures that Appendix K specifies (e.g., dwell times, angles, distances, backgrounds), the camera configuration, or the operating envelope criteria. Other commenters (0814-IPAA, 0945/1373-JOFA) noted the documentation of specific procedures used for the QA verification video monitoring requirements (e.g., dwell times, angles, distances, backgrounds) in the monitoring plan will change based on individual site-specific requirements. One commenter (0808-API) further contested that video of OGI camera operators who know they are being videoed is unlikely to be representative. Commenters (0911-NDPC, 0954-FLIR) noted that a daily video requirement has not been required for prior technologies, including EPA Methods 9, 21, and 22.

One commenter (0782-BHE) pointed out a conflict between the requirements on the amount of time for daily QA videos in section 9.7.3 (five minutes) versus section 11.2 (5-10 seconds of video). Commenters (0782-BHE, 0954-FLIR) noted that if the QA video requirement is retained, the shorter time of 5-10 seconds is adequate.

One commenter (0911-NDPC) explained that video recordings may be infeasible; the commenter stated that companies with multiple sites generally have one monitoring plan that covers all sites, with separate site-specific information (e.g., walking paths) included, and many companies prohibit walking while viewing through a camera due to safety considerations. The commenter urged that companies should be allowed to define their own QA/QC procedure in their monitoring plans. Another commenter (0814-IPAA) proclaimed that the 5-minute video requirement would substantially reduce the life of the camera and require unnecessary and costly maintenance and replacement. The commenter further stated that section 9.7.3 would require massive amounts of data storage over the 5-years of recordkeeping requirements, and the necessary documentation of procedures the OGI camera operator uses will change based on individual specific site requirements.

One commenter (0808-API) further asserted that the QA video would require extensive video records that are difficult to reliably store, provide no useful information, are unlikely to ever be reviewed, and would be overly burdensome. Another commenter (0911-NDPC) stated that the videos would provide no value to the operator and will be a great burden to retrieve, review, and transfer if requested by state agencies or EPA. Commenters (0814-IPAA, 0945/1373-JOFA, 0954-FLIR) expressed concern that EPA has underestimated the burden of storing video files; one commenter (1391-INGAA) specifically stated the QA video would require multiple SD cards to save and upload footage, without clear benefit. Another commenter (0954-FLIR) noted the 5-minute video would require approximately 75 megabytes of storage; assuming an OGI

camera operator works five days a week for forty weeks or more a year, this would result in over 15 gigabyte of storage capacity for a single operator annually. One commenter (0808-API) provided as evidence examples of data storage issues associated with 40 CFR part 63, subpart CC, which requires recordkeeping of photos taken of a flare every 15 seconds. The commenter noted that for at least one company operating several refineries, the flare images are not stored on a cloud, but are saved locally on a server, primarily for security. The commenter pointed out that facilities could experience data loss due to power outages or other technical issues associated with handling the sheer volume of images.

Some commenters (0561-TRICORD, 0604-Providence) recommended that in lieu of a 5-minute video, EPA adopt a 1-minute video to record the imaging procedure to alleviate storage concerns; one commenter (0561-TRICORD) suggested that this could be taken quarterly instead of daily. Another commenter (0816-Montrose) supported recordings of surveys and suggested language for retaining a video of surveys (including documentation of fugitive emissions or found leaks) for a minimum of three years; the commenter suggested that three years of bimonthly OGI surveys from a typical facility could be stored on a 2-terabyte external hard drive (costing approximately \$50) and would eliminate the need for a five-minute QA video.

Response I-22-96: EPA considers the requirement for a daily QA video a reasonable alternative to requiring full survey videos. While we agree that it is not necessary to keep a full video of a monitoring survey, it is important to be able to assess each OGI camera operator's technique when reviewing survey records, as the ability to find leaks that are present is dependent on the camera operator's technique. The daily QA video allows someone who is not present for the survey to determine whether an OGI camera operator uses proper technique on a day-to-day basis. This documentation is especially important for a delegated agency to have available in their review of OGI survey records and to assess whether Appendix K is being properly implemented. EPA notes that if an OGI camera operator does keep a video of the full survey, this can also be used to satisfy the requirement for a daily QA verification video.

EPA acknowledges that there is no video requirement in EPA Methods 9, 21, and 22. However, there are no requirements involving a camera in those EPA methods, and as such, it would not make sense to require a recording of the instrumentation. OGI surveys are performed with a camera, and an operator only needs to hit the record button to record a survey. This is analogous to writing down the readings taken with an EPA Method 21 analyzer or noting the opacity read by the observer's eye in EPA Method 9.

EPA disagrees that video recordings are infeasible. EPA does not encourage OGI camera operators to survey or record video during times when they are walking, and we are only requiring video to be taken when an OGI camera operator is actively conducting a survey. EPA also disagrees that recording video reduces the lifespan of an OGI camera; no data was submitted to substantiate this claim. Recording some or all footage of an OGI survey is a practice used by many OGI camera operators and is a requirement for those owner and operators complying with the AWP. OGI camera operators performing surveys under the AWP have not provided EPA with any evidence that the recording requirement has reduced the lifespan of their OGI cameras.

EPA does not consider a 5-minute video clip cost prohibitive, even if the video clip is taken daily. According to one commenter, the average size of a 5-minute OGI video clip is 75 megabytes; if a clip is taken each business day of the year, this will equate to just under 20

gigabytes of data. Cloud storage of files generally runs in the range of \$5-\$10 for a terabyte of storage, or as one commenter noted, a 2-terabyte external hard drive costs approximately \$50. EPA does not consider these storage costs to be cost prohibitive. EPA notes that data loss is a potential issue for any recordkeeping requirement, and it not unique to the recordkeeping requirements within Appendix K.

Regarding the suggestion to change the duration of this video requirement, EPA disagrees with the commenters. The intent of the QA video is to evaluate the OGI camera operator's survey process, not to document that the QA verification tasks in section 9.1 of Appendix K have been completed. Nor is there conflict between the video requirements for documenting leaks and the QA video requirement. The QA video requirement is meant to document the OGI camera operator's survey technique, and should include periods where there are no leaks, not just periods where there leaks. Additionally, we do not consider 1 minute of video enough time to assess the technique of an OGI camera operator. As one commenter implied, OGI camera operators who know the survey is being recorded are likely to change their survey technique during that period; however, it is more difficult to maintain a different technique for 5 minutes than for just 1 minute. Requiring a longer QA video will encourage the OGI camera operator to maintain the proper technique throughout the survey and is more likely reveal instances where an OGI camera operator does change techniques for the QA video. As such, we are retaining the length of the QA video as 5 minutes.

Also, in response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>55</sup>

### ***22.7.9 Monitoring Regulated Components***

Comment: One commenter (0782-BHE) urged that all three options for demonstrating the entire facility is included in the survey in section 9.3 of Appendix K are overly onerous, unjustified, and unsupported; the commenter pointed to EPA Method 21, noting that the standard does not place a restriction on route path or GPS tracking. The commenter explained that the requirement to include GPS route tracing to track survey paths would be burdensome and may further complicate path corrections or adjustment due to facility activities (e.g., safety, access during unit maintenance, etc.) or weather events. The commenter also questioned whether the costs and labor for this provision was adequately considered.

Two commenters (0808-API, 0831-AXPC) suggested that section 9.3 be replaced in its entirety with the language in NSPS OOOOa. One commenter (0808-API) explained that the three proposed approaches appear to be written for larger operations with multiple monitoring locations and significant resources. The commenter remarked that many locations subject to the current rule are smaller facilities or portions of a facility, where monitoring would require one pair of observations or at the most a few observations, and the current requirements would

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<sup>55</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

impose burdensome and repetitive route maps, maintenance of location markers, or identification of GPS coordinates for these smaller sources.

Other commenters (0814-IPAA, 0945/1373-JOFA) urged that the survey techniques should have the flexibility to meet the needs of the producer and should allow for modifications for business size and staff, communication ability (in remote areas), availability of on-site maintenance staff, and fluctuations in daily operational agendas.

Some commenters (0808-API, 0814-IPAA) recommended an additional fourth option that could apply to facilities where less than 25 monitoring observations points are needed to monitor all components regulated by a referencing subpart or permit. The option would allow the monitoring plan to include a description of the approach used (e.g., monitoring all components from two views at least 90 degrees apart) and a list of the facilities or facility locations to which the option applied. Another commenter (0831-AXPC) supported the same option but applied it to facilities where less than 10 monitoring points are needed to monitor all components.

Commenters (0808-API, 0831-AXPC) implored that EPA should at least allow a mix of the current options provided all components are monitored; the commenters asserted that for larger facilities or facilities with a mix of densely located components and remote locations, a mix of the options would be most efficient.

Commenters (0808-API, 0831-AXPC) also asserted that the route maps, GPS coordinates, and site lists required by section 9.3 are laborious and requested that these records be allowed to be kept in electronic form and not “included as part of the monitoring plan”. One commenter (0831-AXPC) suggested including a description of the walking path instead of specific observation paths. Conversely, another commenter (0561-TRICORD) stated that it would not be sufficient to simply have a map with observation locations marked on it, but that there would have to be corresponding markers (e.g., signage) as suggested in section 9.3.2, placed in the field to accurately align the camera operator with the map’s observation points.

Commenters (0808-API, 0831-AXPC) also requested that EPA should clarify that a component database is not required. One commenter (0599-MSC) noted the use of a component database for an OGI-based LDAR program is inappropriate and negates one of the major advantages of OGI.

Response I-22-97: EPA disagrees that the three options presented in section 9.3 of Appendix K are overly burdensome and unnecessary. The purpose of section 9.3 is to ensure that the OGI camera operator will image all regulated components; this is especially important as there is no requirement for a video record of the survey. In an EPA Method 21 based LDAR program, owners and operators generally note the reading for each component, thus showing that each component is monitored; there is no analogous requirement for an OGI survey unless a video record is stored. In lieu of requiring video records in Appendix K, EPA is requiring a choice of different approaches that must be implemented to ensure all regulated components are monitored.

EPA disagrees that the language from NSPS OOOOa should be written into Appendix K. NSPS OOOOa applies to well sites and compressors stations. These are generally small sites with few regulated components, making it easier to ensure that all regulated components are imaged by



the OGI camera during a survey. Appendix K is intended to apply to a range of sites, including very large industrial facilities with hundreds of thousands of regulated components, where it will be much more difficult to view all regulated components without prior planning on how this will be accomplished. As such, EPA has determined that it is important that owners and operators choose from a set of prescribed techniques to show they are viewing all regulated components.

Commenters did not provide information on why smaller sites (with less than 10 or 15 monitoring points) could not use one of the approaches already listed in section 9.3 of Appendix K or why these approaches are burdensome for a small site. Additionally, commenters did not provide information on what type or approach these sites might use instead of the approaches listed in section 9.3. Commenters also did not provide information on why a description of a walking path is less burdensome than providing the specific observation path with observation points marked. EPA considers this alternative less desirable to achieving the desired goal of ensuring all regulated components are imaged, as an OGI camera operator may not know all the required observations points from a written description of a walking path. Additionally, it is much easier and quicker for an OGI camera operator to look at a map than to read a written description.

EPA disagrees that having a map with observation locations marked on it is not sufficient for determining that an OGI camera operator has viewed all regulated components. If an owner or operator also has corresponding markers in the field to accurately align the camera operator with the map's observation points, we encourage these extra measures, as well as any other extra measures taken by the owner or operator to ensure all regulated components are monitored.

In the December 2022 Supplemental Proposal, EPA clarified in section 9.3 that owners and operators may use a combination of the listed methodologies. Additionally, EPA clarified in section 12.1 that records (including the monitoring plan) may be kept in hard copy or electronic form. EPA agrees with commenters that Appendix K itself does not require a component database; reference to a component database was removed from section 9.3 in the December 2022 Supplemental Proposal.

EPA acknowledges that EPA Method 21 does not place restrictions on a route path or GPS tracking. However, LDAR programs that use EPA Method 21 generally have intensive recordkeeping requirements, including component databases. Section 9.7.3 of Appendix K is meant to replace this requirement while still ensuring that all regulated components are imaged by the OGI camera.

EPA is not currently aware of another approach that would effectively ensure an owner or operator monitors all components regulated by a referencing subpart. If an owner or operator develops a new methodology that can achieve this goal, the owner or operator may submit a request for alternative monitoring procedures under 40 CFR 60.13(i) or 40 CFR 63.8(f), as applicable. Additionally, when Appendix K is applied to a specific subpart through a rulemaking, commenters may request that additional methodologies be added for use of Appendix K in that subpart.

Also, in response to the comments received on the November 2021 Proposal, EPA proposed a different regulatory approach for fugitive emissions from well sites, centralized production facilities, and compressor stations in the December 2022 Supplemental Proposal. For details, please see discussion in section IV.A.1.a.ii and IV.A.2.A of the December 2022 Supplemental Proposal related to fugitive emissions from well sites, centralized production facilities, and compressor stations.<sup>56</sup>

Comment: One commenter (0945/1373-JOFA) included a 10-step guide for survey techniques. The steps provided by the commenter include the camera operator performing beginning-of-day and field calibration verification using Eastern Research Group, Inc's "Disposable Lighter Mass Emissions Study" to confirm the OGI camera's operational capability; identification of leaks using the high sensitivity mode with the correct temperature alignment to control ambient background temperature interference; flagging and marking the exact component leak location and date of detection; documentation of leaks via digital OGI photograph and specifics of the leak (e.g., component type, location of the leak) in a field book; communicating the field notes to the operations or maintenance manager at the end of each facility survey or survey day; where no leak is found, documenting via high-quality photograph with the OGI camera that a survey was completed; conducting end-of-day field calibration verification; and creation of a detailed report capturing location, weather conditions, found leaks, repair dates, etc.

Another commenter (0814-IPAA) noted that EPA commissioned the Eastern Research Group, Inc. a couple of years ago to develop a quick calibration field protocol meant to allow quick calibration and verification of the camera. The resulting "Disposable Lighter Mass Emissions Study" was approved by the EPA for use and required the calibration and verification technique be conducted at the beginning and end of each survey day. The technique involved a 13 to 19 second video using a butane lighter to capture a video using each camera setting. The commenter stated this technique is efficient and effective, and a senior level certified OGI operator member of the group indicated that EPA field staff stated this methodology was created because EPA inspectors often fly to various areas and couldn't find the necessary equipment to conduct the original calibration and verification requirements. Allowing this technique to continue would allow EPA inspectors and private OGI camera operators to fly, rental car, stop at any gas station, buy a lighter, and easily conduct a calibration and verification in the field. The proposed regulations in Appendix K will create a similar situation which would complicate both the EPA's field staff ability to meet their own rules and prohibit private OGI camera operators from completing EPA required monitoring for oil and gas facilities.

Response I-22-98: EPA acknowledges the information provided by the commenters. The daily field verification check in Appendix K can be performed with a butane lighter, and as such, we disagree that the procedure complicates the ability of EPA field staff or OGI camera operators to meet the requirements in Appendix K nor does this field check vary significantly from current field practice.

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<sup>56</sup> 87 FR 74722-74736 and 74739 (December 6, 2022).

EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in section VI of the December 2022 Supplemental Proposal for information related to the changes made to Appendix K.<sup>57</sup>

## **22.8 Records and Reporting**

### ***22.8.1 Excessively Burdensome and Costly Requirements***

Comment: Several commenters (0749-PAW, 0750-Flogistix, 0777-Ascent, 0782-BHE, 0808-API, 0831-AXPC, 0911-NDPC, 1391-INGAA) stressed the importance of carefully evaluating the amount of additional recordkeeping burden required in Appendix K, especially regarding small businesses and the current NSPS OOOOa requirements. Commenters stated that additional monitoring plan, recordkeeping, performance auditing, and prescriptive OGI camera operating requirements would add unnecessary cost and nearly eliminate the advantages of using OGI cameras over EPA Method 21. One commenter (1391-INGAA) stated that the viewing and recordkeeping requirements should be simplified and streamlined. Another commenter (0749-PAW) noted that facilities will incur other indirect costs due to the need for additional monitoring plan and recordkeeping requirements to implement Appendix K; the commenter urged EPA to address this additional documentation in evaluating the burden and cost-effectiveness of the rule. A commenter (0777-Ascent) asserted that the additional requirements of Appendix K will require that owners, operators, and OGI contractors dedicate significantly more time away from actual monitoring surveys.

Response I-22-99: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal, including revisions to the recordkeeping requirements. See discussion in section VI of the December 2022 Supplemental Proposal for information related to the changes made to Appendix K.<sup>58</sup>

### ***22.8.2 Ownership of Records***

Comment: Multiple commenters (0463-Southern Ute, 0782-BHE, 0808-API) raised concerns regarding ownership of various records and requested flexibility in who, where, and how records are maintained. Some commenters (0808-API, 0831-AXPC) asserted that, as written, the ownership of various requirements was unclear; one commenter (0808-API) asserted that the information required is not site-specific and may be generic for a particular camera or monitoring approach. Commenters (0808-API, 0831-AXPC) requested that EPA either reconsider assigning requirements to the site or provide flexibility to allow facilities to assign responsibility to reduce unnecessary or duplicative requirements.

Commenters (0808-API, 0831-AXPC) stated that there are requirements assigned to the site that could fall under the responsibility of a contract monitoring organization and therefore could apply at multiple sites. These commenters (0808-API, 0831-AXPC) provided as an example the development of procedures that describe how components will be viewed with the OGI camera (section 9.4) and the requirement to have a plan for avoiding camera operator fatigue (section

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<sup>57</sup> 87 FR 74837-74842 (December 6, 2022).

<sup>58</sup> 87 FR 74837-74842 (December 6, 2022).

9.5). One commenter (0808-API) suggested that to reduce confusion rather than trying to list who should be responsible for each procedure in section 9, the requirements should be reworded to simply identify the monitoring plan content without specifying who is responsible.

Several commenters (0808-API, 0831-AXPC) contended that records should not be kept on a “facility” basis. The commenters stated that many of the required records would be developed by the camera manufacturer, while others could be maintained in owning or operating company central repositories, or, in other cases, handled by the OGI camera operator’s employer (e.g., a monitoring company). The commenters pointed out that many cameras will be used at multiple facilities and may not be owned by the facility or even the facility owner. One commenter (0808-API) asserted that a site monitoring plan would be the responsibility of an OGI camera owner or monitoring contractor. The commenters (0808-API, 0831-AXPC) recommended the word “facility” be deleted from section 12 and the appropriate entity (e.g., OGI camera owner, facility owner or operator, OGI camera operator employer) be substituted, or that no specific entity be identified as having to maintain the record.

One commenter (0808-API) recommended that the recordkeeping requirements be revised to require the OEM or other entity that performs the section 6.1.2 evaluations to maintain the records showing compliance with the minimum detection limits and that such a record not be required to be kept by the OGI camera owner or at each location where the camera is used.

Commenters (0782-BHE, 0808-API, 0831-AXPC) noted that records of data supporting development of the operating envelope should be kept by the camera manufacturer, records applicable to OGI camera operators kept by the OGI camera operator’s employer, and records of actual surveys maintained by the owner/operator of the monitored site. One commenter (0782-BHE) specifically expressed concerns with the requirement to retain all data supporting development of the operating envelope, which, the commenter asserted, “could include thousands of site-specific components at each camera and atmospheric test condition over the myriad of facility configurations”. The commenter suggested that these requirements, and other OEM specification criteria, are best addressed by the OEM initial performance testing, and the owner or operator should only address anything outside of these test conditions in the monitoring plan. The commenter further stated that several requirements in the summary table in section 11.3 of Appendix K (e.g., spectral bandpass range and initial performance verification) should not be the responsibility of the operator.

Commenters (0808-API, 0831-AXPC) additionally stated that EPA should clarify that not everyone that has to records of the development of the operating envelope. One commenter (0808-API) discussed the necessary documentation and recordkeeping requirements specified in section 8.1 for each OGI camera. The commenter called attention to the fact that these cameras will be used at multiple, separate facilities owned by different entities, and it would be difficult for every entity that uses the camera to maintain a copy of that documentation. The commenter recommended that records required under section 8.1 should be relocated to section 6 of Appendix K and maintained by the organization doing the demonstration.

Commenters (0808-API, 0831-AXPC) requested that records of operating training activities, including training surveys performed to locate leaks, be maintained with the training and

monitoring records under sections 12.4.3 and 12.5 of Appendix K. The commenters also stated that the requirement that the records in section 12.5 of Appendix K be made available to technicians executing repairs is overly burdensome, asserting that most items are not associated with repairs or locating the leak.

One commenter (0463-Southern Ute) stated that it is often not feasible for records to be kept on site at a facility due to storage limitations or environmental considerations such as lack of electricity (such as at well sites). The commenter requested the option to keep records readily available at an alternative location.

Response I-22-100: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal, including revisions to the recordkeeping requirements. These revisions included clarifying which records need to be kept by the owner or operator and which records need only be accessible to an owner or operator (and available to the Administrator for review upon request). Where an owner or operator must maintain records, Appendix K does not require that records be kept at a particular site; instead, Appendix K states that these records must be retained and easily accessible.

EPA also clarified in the December 2022 Supplemental Proposal that the initial OGI camera specification testing and development of the operating envelope can be performed by the owner or operator, camera manufacturer, or a third-party. However, regardless of who performs the testing, the owner or operator must have access to these records in order to ensure that the OGI camera meets the requirements of Appendix K, as it is the ultimate responsibility of the owner or operator to conduct surveys meeting the requirements in Appendix K, if a subpart requires the use of Appendix K.

EPA made changes to the records in proposed section 12.5 (now section 12.6) of Appendix K in the December 2022 Supplemental Proposal. EPA notes that the records in this section are records of the initial survey. EPA does not consider the requirement to make the initial survey records available to the person who will be conducting repairs overly burdensome. We consider it appropriate to make the initial survey records available to the person making repairs, as the person making repairs may need additional information to complete the repairs, especially if the initial inspection misidentifies the component that is leaking or if there are multiple components in a grouping that are leaking.

Comment: One commenter (0599-MS) questioned why records are required to be retained for the lifetime of equipment, when the survey records themselves are only required to be kept for 5 years (or as otherwise required by a regulation or permit).

Response I-22-101: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal, including revisions to the recordkeeping requirements. These revisions included clarifying the length of time different types of records need to be kept to better align the OGI camera records with the OGI survey records.

### ***22.8.3 Survey Records***

Comment: Several commenters (0599-MSD, 0718-Tora, 0782-BHE, 0808-API, 0814-IPAA, 0831-AXPC, 0911-NDPC, 0945/1373-JOFA) objected to the requirement to maintain 10-second OGI video clips of leaking components. Commenters (0782-BHE, 0808-API, 0814-IPAA, 0945/1373-JOFA) expressed that the requirement is unnecessary, overly burdensome, and would require massive amounts of storage space. Commenters (0782-BHE, 0808-API, 0814-IPAA) proclaimed that EPA did not consider the additional cost of data storage for the 10-second video clips for a minimum of five years. One commenter (0782-BHE) noted that the added burden of maintaining video records from site surveys would add to the time to complete the surveys, require modifications to existing field programs and data collection practices, and would add to the labor resources required to complete the leak surveys. The commenter requested additional justification for these requirements and that the requirements be accurately reflected in the cost-effectiveness analysis. Commenters (0718-Tora, 0814-IPAA) stated that the quality of OGI video clips is poor and would not be useful for maintenance personnel. A different commenter (0599-MSD) noted that in a proficient LDAR program, surveys are conducted with appropriate staff so that detected leaks are repaired simultaneously when possible, and that a color still image serves the same purpose and provides a clearer and more detailed image while enabling more efficient use of survey time. One commenter (0808-API) requested that EPA allow either a video or a digital picture and only impose the requirement where a leak is not immediately repaired or tagged, and that only a written record of the leak information be required otherwise. Another commenter (0831-AXPC) supported removing any requirements related to digital photograph or videos related to OGI.

One commenter (0814-IPAA) noted that EPA originally supported OGI inspections as a quick and efficient alternative to EPA Method 21, allowing companies to survey thousands of components quickly and allowing efficient communication to staff for repair. The commenter urged that a 10-second video for each leak would be impossible to quickly communicate necessary repairs, due to file size and video quality. The commenter asserted that the low-quality video would make an accessory, high-quality digital photograph also necessary to document and communicate a leak. Commenters (0814-IPAA, 0945/1373-JOFA) stated that high-quality digital images are small and easier to communicate and pointed out that OGI camera videos may be easily corrupted.

Other commenters (0463-Southern Ute, 0808-API) noted that a digital photograph allows for identification of leaking components without tagging and is preferred when physical tagging may not always be possible due to safety considerations (e.g., hot equipment, where no safe access is available, or where toxics may be present). Commenters (0463-Southern Ute, 0808 API) specifically requested that EPA allow the same alternative provided in NSPS OOOOa to use a digital photograph in lieu of tagging. One commenter (0463-Southern Ute) pointed out that such photographs clearly identify locations, are easily shared, and allow for gathering of appropriate resources without requiring a trip to the site. The commenter also stated that a high-quality digital photograph can help target repairs of leaks where the exact source cannot be identified and are preferred to physical tagging that is susceptible to failure due to weather exposure.

Some commenters (0718-Tora, 0814-IPAA) asserted that the requirements for tagging and notation of date, time, and location should be sufficient for leak documentation. One commenter (0718-Tora) urged that documentation that the OGI camera operator remained within the operating envelope and followed the procedures of the monitoring plan can be achieved through an affirmative statement made by the OGI camera operator, with periodic auditing.

Several commenters (0782-BHE, 0808-API, 0831-AXPC) specifically supported the exclusion of video-recordings for non-leaking components in section 9.7.2 of Appendix K, which they cited as a large improvement from the AWP.

Response I-22-102: In response to comments on the November 2021 Proposal, EPA updated the survey documentation requirements to require either a short video clip or a photograph of each leak in the December 2022 Supplemental Proposal.

EPA disagrees that there should not be a video or photograph documentation of all leaks. EPA acknowledges that the requirement to keep video clips or photographs is different from other LDAR programs. However, LDAR is generally performed using EPA Method 21, and during an inspection, the operator documents the EPA Method 21 reading when a leaking component is found. Taking a photograph of a visual OGI image is analogous to documenting the instrument reading when using EPA Method 21.

The requirement to tag a component for repair is only applicable if the repair cannot be made immediately. A photograph of the component may not be enough to identify the component if there are multiple components in the vicinity of the leak. EPA notes that tagging components is a requirement in most leak detection programs and provides an easy way for a technician to locate the correct component in the field. As such, we are retaining the requirement to tag components that cannot be immediately repaired at the time of inspection.

#### ***22.8.4 Documentation of Ambient Weather Changes***

Comment: Several commenters (0718-Tora, 0808-API, 0814-IPAA, 0831-AXPC, 0945/1373-JOFA) questioned requirements to document weather conditions at the beginning of each survey, when transitioning between process areas, and at the end of each survey. Some commenters (0808-API, 0814-IPAA, 0831-AXPC) contended that the requirements apply to an undefined and ambiguous “monitoring survey”, noting that the length of a survey of a single site or even a single process can take between an hour and several days to complete. One commenter (0599-MSD) noted that major process area is not defined, nor should it be defined or included. Commenters (0808-API, 0817-GPA, 0831-AXPC) saw no value in documenting weather data when monitoring moves from one process unit to another at the same location or at the end of the day, urging that weather does not change significantly due to location changes within a facility. One commenter (0718-Tora) expressed that the weather conditions recorded would not necessarily be indicative of conditions throughout a survey (e.g., a wind speed record generated during a calm period on a gusty day), therefore, such requirements would not serve to demonstrate whether conditions are within the OGI camera operating envelope. Commenters (0808-API, 0831-AXPC) added that end of day weather information is of no use in assuring operating envelope requirements are being met, since monitoring has concluded for the day. One

commenter (0599-MSD) stated that recording conditions at the end of the survey only serves to collect data which would be used to scrutinize or invalidate collected survey data, although if the OGI camera operator utilized proper technique, the data could not be invalidated. The commenters (0599-MSD, 0808-API, 0831-AXPC) requested that the requirement to record survey identifying information, including weather conditions, be revised to so that information is only required at the start of the monitoring day or whenever there is a change in facility. Another commenter (0817-GPA) suggested that, at most, EPA should require new conditions be recorded if weather conditions change substantially during the survey, while a different commenter (0718-Tora) urged that an affirmative statement by the OGI camera operator should be sufficient to document that conditions are appropriate.

Some commenters (0814-IPAA, 0945/1373-JOFA) requested that EPA clarify the time intervals of weather documentation. These commenters noted that for small marginal wells, an OGI survey may only take 15 minutes to observe all components, as opposed to a full day or more for large processing facilities. The commenters questioned whether operators would be required to document weather changes in intervals of less than 15 minutes and remarked that this would be impractical and time consuming.

Response I-22-103: In the December 2022 Supplemental Proposal, EPA updated the requirements in section 9.6.2 of Appendix K concerning recording weather conditions to remove ambiguity. Weather conditions must be recorded at the beginning and end of the monitoring survey, and if the monitoring survey is greater than four hours, at least once every two hours. EPA disagrees with the commenters that it is unnecessary to record weather conditions at regular intervals. EPA notes that the weather conditions are a relevant component of how a survey is conducted. Wind speed and temperature are directly related to how an OGI camera operator uses the camera's operating envelope, and as such, an operator needs to be always aware of these parameters and any changes in these parameters. Sky conditions are important to understanding the types of backgrounds that may be present during the survey, which is related to the OGI camera operator's ability to find a suitable delta-T. Understanding the conditions of a survey are crucial to anyone who is reviewing the results of a survey, as well as to the person conducting the survey.

## **22.9 Other Comments**

### ***22.9.1 Section 5.0 - Safety***

Comment: Three commenters (0808-API, 0831-AXPC, 0911-NDPC) discussed the applicability of safety requirements in Appendix K. Two commenters (0808-API) and (0831-AXPC) recommended that EPA remove the last sentence of section 5.1, while the other commenter (0911-NDPC) urged EPA to remove the section on safety in its entirety.

Response I-22-104: EPA disagrees with the commenters. Safety is a topic covered in most EPA test methods, and EPA used similar language in Appendix K. EPA does not prescribe particular safety protocols that must be followed in Appendix K. Appendix K only recommends that the user be aware of the hazards that may exist at the site and with prolonged use of an OGI camera. EPA sees no reason why this information should not be included within Appendix K.



### ***22.9.2 QA/QC Requirements in Section 11.0***

Comment: One commenter (0808-API) provided recommended revisions in the redline version of section 11.3 of Appendix K, as well as suggested improved wording and addition of specific references in the frequency column of the table where the commenter indicated it is unclear as to who is responsible and how often and on what basis the QA/QC activity is required.

Response I-22-105: EPA acknowledges the input provided by the commenter. Some of the suggested changes were incorporated in the December 2022 Supplemental Proposal.

### ***22.9.3 Solicitation of Input***

Comment: Commenters (0814-IPAA, 0945/1373-JOFA) are concerned that EPA only solicited input from OGI camera manufacturers before designing the proposed requirements. The commenters noted that manufacturers have a vested interest and desire to maximize camera use in order to expedite the failure rate and drive-up maintenance and new sales revenue from the excessive camera use outlined throughout the proposed Appendix K. One of the commenters (0945/1373-JOFA) requested that EPA divulge who EPA solicited comments and input from before designing the proposed requirements and requested, and for transparency, whether EPA solicited comments and advice from very small businesses and sole proprietorships prior to publishing the proposed Appendix K.

Response I-22-106: On November 9 and 10, 2020, EPA held a virtual stakeholder workshop to gather input on development of a protocol for the use of OGI. This workshop was open to the general public and attended by approximately 300 people. The workshop had two components. Half of the workshop was dedicated to presentations from a variety of stakeholders, including OGI camera manufacturers, regulated industry, researchers, LDAR contractors, universities, an independent laboratory, and a state environmental agency. The second half of the workshop was an open forum on specific topics where everyone present was given an opportunity to speak and provide input. The workshop findings are summarized in a report available in the docket for this rulemaking.<sup>59</sup>

EPA also provided a list of meetings held prior to the development of Appendix K in the docket for this rulemaking.<sup>60</sup> This included meetings with regulated industry and different camera manufacturers. Additionally, as noted in the Appendix K TSD, EPA conducted extensive literature searches and performed its own studies of OGI cameras. The TSD is the basis of the development of Appendix K.

### ***22.9.4 Separate Appendix K Final Rule***

Comment: Commenters (0793-PBPA, 0794-MHAN, 0749-PAW, 0816-Montrose, 1291-INGAA) recommended that EPA re-write Appendix K and engage with stakeholders and operators with experience in OGI to do so. In addition, commenters recommended that EPA separately propose

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<sup>59</sup> EPA-HQ-OAR-2021-03017-0077.

<sup>60</sup> EPA-HQ-OAR-2021-03017-0078.

Appendix K's OGI requirements on a standalone basis for industry-wide review and comment and drop the proposed requirement in the context of this regulatory proceeding.

Response I-22-107: In order to finalize the BSER for gas processing plants in NSPS OOOOb and EG OOOOc, which is OGI monitoring according to Appendix K, EPA must finalize Appendix K either before or in conjunction with NSPS OOOOb and EG OOOOc. As such, we are not separating the finalization of Appendix K from this rulemaking.

As part of the development of appendix K, EPA conducted an extensive literature review on the technology development as well as observations on current application of OGI technology. EPA also commissioned multiple laboratory studies and OGI technology evaluations. Additionally, on November 9 and 10, 2020, EPA held a virtual stakeholder workshop to gather input on development of a protocol for the use of OGI. The information obtained from these efforts was used to develop the TSD for appendix K, which provides technical analyses, experimental results, and other supplemental information used to evaluate and develop standardized procedures for the use of OGI technology in monitoring for fugitive emissions of VOC and methane from industrial environments. EPA initially proposed Appendix K in the November 2021 Proposal and took comment on that proposal. EPA provided an overview of the proposal during a webinar on December 14, 2021, and responded to clarifying questions during the webinar. Based on comments received on the initial proposal, EPA developed a revised Appendix K, which was proposed as part of the December 2022 Supplemental Proposal, and we took comment on the revised version of Appendix K. EPA has provided substantial notice of the requirements in Appendix K and multiple opportunities for stakeholders to provide input.

#### ***22.9.5 Focus Appendix K***

Comment: One commenter (0782-BHE) argued that Appendix K should focus on the ability of the technology to detect leaks that materially contribute to emissions. The commenter stressed that EPA Method 21, which relies on concentration, is a poor surrogate for leak rate mass emissions, and in some cases, a concentration can result in more leaks being tagged and subsequently repaired than necessary. The commenter contended that EPA should develop a decision-basis for leak repair or a tier-based programs that considers leak size and that EPA has not accounted for the cost of tracking and repairing small leaks. The commenter further requested that EPA ensure that the primary focus of an OGI program is to locate and eliminate “meaningful” or significant leaks that account for a large proportion of overall emissions. The commenter criticized the Appendix K criteria as “pursuing perfection”, highlighting the contrast between Appendix K and the actual performance of EPA Method 21 surveys, noting that facilities continue to achieve significant emissions reductions with OGI that would be ignored by EPA Method 21 under the current methodology. The commenter stated that the costs of tagging, tracking and repairing components under Appendix K may not be justifiable and cautioned against trying to identify *all* small immaterial leaks because it may have limited impact, add significant costs, or deplete available qualified technicians and resources that might better be applied elsewhere. The commenter cautioned that adding unnecessary “rigor” to the requirements may add time and cost to an approach that has proven to be more advantageous over conventional EPA Method 21-based LDAR.

Response I-22-108: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in section VI of the December 2022 Supplemental Proposal for information related to the changes made to Appendix K.<sup>61</sup>

EPA notes that the commenter is correct that EPA Method 21 relies on concentration. However, we note that the ability of an OGI camera to image a leak relies on concentration-pathlength, not on mass emissions. For this reason, it can be difficult to determine if an OGI camera is seeing a large leak or small leak, which makes creating a tiered program impossible. EPA disagrees that it is pursuing perfection with Appendix K. EPA is providing requirements within Appendix K to help ensure that OGI camera operators find leaks that exist to ensure that LDAR programs that use OGI are equivalent to LDAR programs that use EPA Method 21, as effective OGI surveying is highly dependent on OGI camera operator training and experience, as well as site conditions (such as wind speed).

#### ***22.9.6 Editorial Changes***

Comment: A commenter (0808-API) noted a typographical error where section 10.4.2.2 was labeled as 10.4.2.3 in the proposed Appendix K.

Response I-22-109: EPA has made the correction to paragraph labeling in the final rule.

#### ***22.9.7 Burden and Cost***

Comment: Several commenters (0814-IPAA, 0935-COGA, 945/1373-JOFA, 1391-INGAA) urged EPA to re-evaluate the financial implications of implementing Appendix K, especially for small businesses who may not have more than one OGI camera operator and remote or difficult to access facilities, as these new practices may prove fiscally devastating and force these smaller businesses to close.

Response I-22-110: EPA made substantial edits to Appendix K in response to comments in the December 2022 Supplemental Proposal. See discussion in section VI of the December 2022 Supplemental Proposal.<sup>62</sup>

Additionally, EPA notes that Appendix K does not on its own apply to any sources. Each rule that implements Appendix K will evaluate the cost of implementation and provide any appropriate leak detection alternatives.

Comment: One commenter (0808-API) stressed that existing cameras have not been tested and certified to meet the proposed Appendix K specifications. The more stringent Appendix K requirements will require retesting of existing OGI cameras and if the camera does not meet these requirements, operators could be required to purchase a new OGI camera, which is an additional cost not considered in EPA's cost analysis.

Response I-22-111: EPA acknowledges the statement of the commenter. Based on the work that was done in support of the TSD for Appendix K, we are confident that cooled MWIR OGI

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<sup>61</sup> 87 FR 74837-74842 (December 6, 2022).

<sup>62</sup> 87 FR 74837-74842 (December 6, 2022).

cameras currently on the market and currently be used for inspection of VOC and methane leaks will be able to meet the specifications outlined in Section 6.0 of Appendix K.

## 22.10 Incorporations by Reference

In some cases, commenters incorporated by reference all or part of a comment letter submitted by another commenter. Rather than repeat the associated comment excerpts for each commenter, the EPA has listed the comment excerpt only once and provided a list of all the commenters who otherwise incorporated the comments by reference in the table below.

**List of Comment Letters Incorporated by Reference**

| Commenter                 | Commenter Affiliation                                     | Incorporations by reference                           | IBR'd DCN                                                                       |
|---------------------------|-----------------------------------------------------------|-------------------------------------------------------|---------------------------------------------------------------------------------|
| EPA-HQ-OAR-2021-0317-0462 | Arkansas Independent Producers and Royalty Owners (AIPRO) | American Petroleum Institute (API)                    | EPA-HQ-OAR-2021-0317-0189; EPA-HQ-OAR-2021-0317-0198; EPA-HQ-OAR-2021-0317-0808 |
| EPA-HQ-OAR-2021-0317-0462 | Arkansas Independent Producers and Royalty Owners (AIPRO) | Independent Petroleum Association of America (IPAA)   | EPA-HQ-OAR-2021-0317-0348; EPA-HQ-OAR-2021-0317-0814                            |
| EPA-HQ-OAR-2021-0317-0748 | American Fuel & Petrochemical Manufacturers (AFPM)        | American Petroleum Institute (API)                    | EPA-HQ-OAR-2021-0317-0189; EPA-HQ-OAR-2021-0317-0198; EPA-HQ-OAR-2021-0317-0808 |
| EPA-HQ-OAR-2021-0317-0779 | Kinder Morgan, Inc                                        | Interstate Natural Gas Association of America (INGAA) | EPA-HQ-OAR-2021-0317-0415                                                       |
| EPA-HQ-OAR-2021-0317-0802 | Kraken Oil & Gas LLC (Kraken)                             | North Dakota Petroleum Council (NDPC))                | EPA-HQ-OAR-2021-0317-0415-0911                                                  |
| EPA-HQ-OAR-2021-0317-0834 | Air Advocacy Coalition (A2C)                              | American Petroleum Institute (API)                    | EPA-HQ-OAR-2021-0317-0189; EPA-HQ-OAR-2021-0317-0198; EPA-HQ-OAR-2021-0317-0808 |
| EPA-HQ-OAR-2021-0317-0916 | Alaska Oil and Gas Association (AOGA)                     | American Petroleum Institute (API)                    | EPA-HQ-OAR-2021-0317-0189; EPA-HQ-OAR-2021-0317-0198; EPA-HQ-OAR-2021-0317-0808 |
| EPA-HQ-OAR-2021-0317-0935 | Colorado Oil and Gas Association (COGA)                   | Western Energy Alliance (WEA)                         | EPA-HQ-OAR-2021-0317-0743                                                       |

|                           |                                                |                                                     |                                                      |
|---------------------------|------------------------------------------------|-----------------------------------------------------|------------------------------------------------------|
| EPA-HQ-OAR-2021-0317-0935 | Colorado Oil and Gas Association (COGA)        | Independent Petroleum Association of America (IPAA) | EPA-HQ-OAR-2021-0317-0348; EPA-HQ-OAR-2021-0317-0814 |
| EPA-HQ-OAR-2021-0317-0935 | Colorado Oil and Gas Association (COGA)        | Petroleum Association of Wyoming (PAW)              | EPA-HQ-OAR-2021-0317-0749                            |
| EPA-HQ-OAR-2021-0317-1458 | Innovative Environmental Solutions, Inc. (IES) | Berkshire Hathaway Energy Company (BHE)             | EPA-HQ-OAR-2021-0317-0782                            |

## Chapter 23. Miscellaneous Other Comments

### 23.1 Statutory Basis for Proposed Rules

Comment: Commenter (0734-ATS) states that under the CAA, the EPA has the authority to regulate the GHG emissions and volatile organic compound (VOC) emissions, which is critical to protecting public health and mitigating the harmful impacts of climate change.

Similarly, commenter (0735-CBF), states that under the CAA, EPA is tasked with “protect[ing] and enhance[ing] the quality of the nation’s air resources so as to promote the public health and welfare and the productive capacity of its population.”<sup>1</sup> They add that section 111 of the CAA requires EPA to identify standards of performance for new categories of stationary air pollution sources if the pollutants they emit cause or contribute significantly to air pollution that may endanger public health or welfare.<sup>2</sup> In 2016, the commenter notes that the EPA promulgated new source performance standards (NSPS) for methane and VOC emissions from oil and gas sources after recognizing the public health and welfare risk caused by methane, a GHG, and a major contributor to climate change.<sup>3</sup>

Response I-23-1: The EPA received similar supporting comments on the December 2022 Supplemental Proposal regarding EPA’s statutory authority under the CAA to regulate GHG and VOC emissions. See Volume II, Chapter 2 (Legal Basis for Rulemaking), subsection 2.1.4 (EPA Has the Authority Under the CAA to Establish State Plan Requirements). These comments are supportive comments; as such, no response is required.

See also, discussions in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

### 23.2 Applicability of Requirements Under the Proposed Rules

Comment: Several commenters (0810-Petroleum Alliance of Oklahoma (Petroleum Alliance-OK), 0457-Southeastern Ohio Oil and Gas Association (SOOGA), 0722-Missouri Department of Natural Resources, Air Pollution Control Program (MDNR), 0743-Western Energy Alliance (WEA), 0755-Texas Pipeline Association (TPA), 0777-Ascent Resources, LLC (Ascent), 0782-Berkshire Hathaway Energy Company (BHE), 0793-Permian Basin Petroleum Association (PBPA), 0808-American Petroleum Institute (API), 0814-Independent Petroleum Association of America (IPAA) *et al.*, 0817-GPA Midstream Association (GPA), 0820-Pioneer Natural Resources USA, Inc. (Pioneer), 0831-American Exploration and Production Council (AXPC), 0911-North Dakota Petroleum Council (NDPC), 0921-U.S. Chamber of Commerce (USCC), 0929-NSWA National Stripper Well Association (NSWA), 0938-Texas Oil & Gas Association (TXOGA), 1289-Atmos Energy Corporation (Atmos), 1391-Interstate Natural Gas Association of America (INGAA), 1421-DePuy Oil and Gas Co. (DePuy)) express that the

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<sup>1</sup> 42 U.S.C. § 7401(b)(1).

<sup>2</sup> 42 U.S.C. § 7411, Standards of Performance for New Stationary Sources.

<sup>3</sup> 40 C.F.R. pt., 60, subpt. OOOOa.

effective/applicability date of requirements for new and existing sources under the November 2021 Proposal needs to be based on the date of the proposal of the regulatory text (with the supplemental proposal) and not based on the November 2021 Proposal date. Some of the examples of comments submitted by commenters are presented in the following paragraphs.

Commenter (0810-Petroleum Alliance-OK) states that since EPA's publication of the November 2021 Proposal did not include any proposed regulatory language, the November 2021 Proposal should not be characterized as a "proposed rule" in which the publication date of November 15, 2021, becomes the applicability date for methane and VOC emissions from sources that commenced construction, modification, or reconstruction. The commenter requests EPA revise the applicability date to align with a forthcoming proposed supplemental rule publication date that contains actual text.

Commenter (0793-PBPA) believes it would be inappropriate for EPA to treat its November 15, 2021, publication as "proposed regulations," as that phrase is used in CAA 111(a)(2) for purposes of establishing an applicability date to distinguish between new and existing sources. By applying the proposed NSPS to sources that are new, modified, or reconstructed after November 15, 2021, as opposed to after whatever date EPA actually publishes proposed regulatory text, the commenter states that EPA will effectively impose a retroactive applicability date that brings in sources as new and subject to NSPS requirements when they should be treated as existing and subject to EG requirements, which are implemented by the states. The commenter notes that the November 15, 2021, publication should be considered an Advanced Notice of Proposed Rulemaking (ANPR).

Commenter (0743-WEA) believes that EPA's classification of the publication in 86 FR 63110 as a proposed rule is inappropriate. They explain that under 42 U.S.C. § 7411(a)(2), "New Source" is defined as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source." For a typical NSPS, the commenter notes that this generally means that compliance is required for those sources that are either modified or constructed after a particular trigger date, based on when regulations are proposed. Within this publication, the commenter notes that EPA states that the types of sources discussed in the document would be required to meet the yet undefined standards in a forthcoming final rule if their construction or modification occurred after November 15, 2021. In the view of the commenter, this approach conflicts with 42 U.S.C. § 7411(a)(2) as there has yet to be a publication of regulations, or proposed regulations.

Commenter (0743-WEA) suggests that EPA recognizes that no publication of proposed regulations or regulatory text has been made, noting that "EPA plans to issue a supplemental proposal and supplemental RIA [Regulatory Impact Analysis] for the supplemental proposal to provide regulatory text for the November 2021 proposed NSPS OOOOb and EG OOOOc." This is reiterated in EPA's supporting fact sheet on the rule proposal: "EPA intends to issue a supplemental proposal in 2022 that will provide proposed regulatory text and may expand on or modify the 2021 proposal in response to public input." The commenter states that EPA is clear in the publication that the actual proposed regulations are forthcoming, and therefore the current

publication would not trigger new source requirements for sources discussed in the publication at the date of its publication.

Commenter (0743-WEA) states that, in addition, EPA intimates that the supplemental proposal could include sources, requirements, and information based on comments received that aren't mentioned in the current publication. If that were to happen, based on EPA's asserted date in the publication of November 15, 2021, the commenter states that the NSPS OOOOb rule could end up having two separate compliance dates based on this current publication and the supplemental proposal, needlessly complicating regulatory compliance for impacted companies.

Instead of proposed regulations and regulatory text, the commenter (0743-WEA) states that the publication in 86 FR 63110 is a lengthy set of information that would typically be included in either the preamble to a rulemaking, or in an ANPR, and some questions that would typically appear in an Information Collection Request (ICR). Given that EPA does identify some potential themes or ideas around what potential regulations in the rule could look like, the commenter suggests that EPA should have classified this publication as an ANPR, as EPA has done with previous rulemaking efforts. That said, according to the commenter, a mere description of potential regulatory requirements that may be proposed in a supplemental proposal is not enough to inform the regulated public how they are to comply with a rule. In this instance, there is yet to be a rule to actually comply with.

Commenter (0743-WEA) notes that by publishing the November 2021 Proposal with a purported compliance date of November 15, 2021, EPA is expecting operators to begin to track facilities that may or may not ultimately be regulated, with regulatory requirements that have not yet been proposed, and are expected to do so in addition to expecting more sources that could potentially be included in the future, all of which could impact compliance budgets, planning, and design. Absent clear guidance, EPA should not expect operators and the regulated public to anticipate the intentions of what a proposed rulemaking would look like in the future when developing plans for facility design, control technologies, and approaches. The commenter recognizes that it would be difficult to reclassify the publication as an ANPR at this stage. As such, to remedy the conflict the publication has with CAA section 111(a)(2), (42 U.S.C. 7411(a)(2)) the commenter encourages EPA to clarify in the supplemental proposal that the compliance date is triggered with the publication of the regulations and regulatory text in the supplemental proposal, whenever that is ultimately published in the *Federal Register*. Going forward, the commenter hopes EPA will avoid publishing documents titled as a proposed rule under the NSPS absent formal regulatory text. The commenter contends that this practice does not allow for sufficient public input and comment when the regulated public has a mere 75 days to comment on only the limited information that would normally be provided in a preamble. The commenter also requests the supplemental proposal to come later this year include a robust comment period for regulated entities to adequately evaluate the impacts of the proposed rule.

Similarly, commenter (0938-TXOGA) states that since the *Federal Register* publication on November 15, 2021, did not contain "proposed regulations," the date of this publication cannot be used to determine applicability of the NSPS that will eventually be codified in NSPS OOOOb. The commenter provides that the CAA does not define the term "regulations" (in section 111 of the CAA or elsewhere), but it is commonly accepted in administrative law that agency



regulations promulgated pursuant to statutory authority are “rules” within the meaning of the Administrative Procedures Act (APA), and the two terms are used interchangeably. Under the APA, an agency “rule” is defined (in relevant part) as “the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy.”

Commenter (0938-TXOGA) asserts that the congressional intent in establishing the proposal date as the trigger date for applicability is based on the actual proposal of rule language. Congress established a rigorous schedule for establishing NSPS, in which standards are to be finalized within a year of proposal. At the same time, the commenter states that the NSPS are intended to support economic growth by being demonstrated and achievable. Thus, Congress reasonably concluded that companies evaluating investments would be in a position to design their facilities to accommodate pending standards at the time of modification if they were on notice of how the regulations would apply. The commenter adds that Congress contemplated that sources should be “on notice” of what would be required of them for the consequence of a proposal to trigger applicability. While it is true that requirements can change from proposal to final, that fact does not undo the fundamental requirement that the level of detail in a proposal that puts the source on notice of requirements be provided in the first instance. Congress’s requirement that NSPS proposals be finalized within a year supports this conclusion. Sources would not reasonably be subjected to an applicability date where the rulemaking is not completed expeditiously. Here, the commenter notes that EPA has called the November 2021 *Federal Register* notice a “proposal” which they say would bring with it necessarily that the rule would need to be finalized by November 15, 2022. Given that EPA must publish and seek comment on regulatory language, and given that the proposed language is unlikely to be available in the *Federal Register* for public review until at least March of 2022, with at least a 30-day comment period, and taking into account that this proposal will require at least 90 days for Office of Management and Budget (OMB) review, the commenter believes it seems improbable at best that this rule could issue within the statutorily required time frame. On this basis alone, the commenter asserts that EPA would need to consider the publication of the proposed regulatory language as the trigger date for applicability.

In sum, commenter (0938-TXOGA) states that for sources to trigger applicability of the NSPS, under CAA section 111, they must be provided reasonable prior notice of the standards that will apply at the time they make the decision to undertake construction, modification, or reconstruction. Publication of the November 2021 Proposal in the *Federal Register* does not provide this information and thus, applicability must be tied to the date an adequate proposal is published. The commenter concludes that releasing a description of what EPA may propose as regulatory text does not satisfy the statutory standard.

Commenter (0938-TXOGA) states that if EPA sought to enforce the conceptual NSPS standards set forth in the November 2021 Proposal against sources that undertook construction or modification between November 15, 2021, and publication of the to-be-issued supplemental proposal (supplying regulatory text), this would raise significant due process concerns under the “fair notice” line of cases in several Circuit Courts of Appeal. The commenter explains that a number of these courts have held that due process precludes enforcement penalties where a regulation is not sufficiently clear to put a regulated party on notice of what is expected of it.

These cases align with the fundamental principle articulated by the U.S. Supreme Court that that “agencies should provide regulated parties ‘fair warning of the conduct [a regulation] prohibits or requires.’” In the analogous context of CAA section 112 maximum achievable control technology (MACT) standard applicability, the Fifth Circuit has determined that a source may not be held, after the fact, in violation of a standard that did not apply at the time that the facility allegedly triggered it (*e.g.*, by commencing a modification). The commenter suggests that EPA keep in mind these commonsense principles and revise the trigger date for NSPS OOOOb applicability when it issues its supplemental proposal.

Commenter (0921-USCC) states that EPA proposed the applicability date of the NSPS OOOOb, as the date of publication of the November 2021 Proposal (November 15, 2021), not from the date of the planned supplemental proposal. If this proposed applicability date is included in a final rule, new, modified, or reconstructed sources built after that date would have to comply with the new standards despite the November 2021 Proposal’s lack of any proposed regulatory text. The commenter contends that EPA’s approach here does not align with the CAA’s definition of a “new source.” Specifically, the CAA defines a “new source” as “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” Since EPA has not yet issued any “proposed regulations,” applicability for NSPS OOOOb cannot lawfully start on November 15, 2021. At the earliest, applicability could start from the date EPA publishes the proposed regulatory text, presumably in the planned supplemental proposal.

Commenter (0921-USCC) states that owners and operators of sources that trigger applicability under the rule must have reasonable prior notice and a clear understanding of the standards prior to commencement of construction, modification, or reconstruction. The commenter states that the November 2021 Proposal without the text of proposed regulations cannot provide adequate guidance to prospective owners and operators of would-be new sources. The commenter notes that EPA did not provide any text that describes with the necessary particularity the requirements with which source owners and operators should plan to comply if they are currently contemplating owning or operating a new, modified, or reconstructed source. The commenter asserts that that EPA should not put new or modified unit owners and operators in a position to guess at these uncertain requirements based on preamble text only. The commenter adds that the practice of issuing NSPS that lack any regulatory text and invoking them as an applicability trigger is arbitrary policy, sets a negative precedent for other NSPS, and is inconsistent with the CAA.

Commenter (0921-USCC) states that one final reason why EPA should not use the November 2021 Proposal’s date of publication as the applicability trigger for NSPS OOOOb is to avoid creating serious enforceability issues by raising due process and fair notice problems. The commenter explains that the fair notice doctrine stands for the principle that a regulated source cannot be enforced against for a standard that did not apply under then-applicable regulations. In *Sierra Club v. Sandy Creek Energy Associates*, for example, the Fifth Circuit articulated this doctrine in the CAA context, finding that new facilities covered by a vacated standard must obtain a case-by-case MACT determination under CAA section 112(g). Likewise, they add that

courts have held that due process would preclude enforcement of standards against a source the owner or operator of which had no prior notice of the standards.

For the stated legal, policy, and enforceability reasons, commenter (0921-USCC) suggests that EPA should amend the applicability date for the NSPS to the publication date of the anticipated supplemental proposal, which will presumably include regulatory text sufficient to trigger applicability.

Commenter (0929-NSWA) expresses concern that EPA states that “methane and VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021” will be required to comply with the proposed “requirements.” Typically, the commenter states that the effective date of NSPS is the date the performance standards are proposed and published in the *Federal Register*. As indicated above, the commenter states that the November 15, 2021, publication in the *Federal Register* contains no proposed regulatory language at all.

Commenter (1289-Atmos) recommends that EPA extend the November 2021 Proposal’s applicability date to the date the agency publishes specific rule language. Because the unique two-step approach EPA is employing for this rulemaking, doing so would be consistent with and better effectuate the purpose of the Part 60 implementing regulations. The commenter states that currently, the November 2021 Proposal would apply requirements under NSPS OOOOb to sources that are new or have been modified or reconstructed after November 15, 2021—the date EPA published the Proposal in the *Federal Register*. However, the commenter notes that EPA’s regulations state that any new or revised performance standard promulgated under CAA section 111(b) applies to “an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.” While EPA has described different potential regulations in the November 2021 Proposal, the commenter notes that it has yet to publish specific rule language, which they state is understandable, as the agency seeks in-depth feedback on many aspects of the November 2021 Proposal. The commenter encourages EPA to release specific proposed rule language for comment, for which the public can then provide additional feedback. This process will give interested parties a chance to fully analyze the details of the rule, which affects complex industries and involves a highly technical body of regulations from both a legal and operational perspective. Specifically, the commenter recommends that EPA extend the Proposal’s applicability date to the date the agency publishes specific rule language.

Commenter (0777-Ascent) appreciates that EPA has already acknowledged that the November 15, 2021, *Federal Register* notice does not constitute a complete proposed rule, as evidenced by EPA’s stated commitment to issuing a supplemental proposal that will contain the proposed regulatory text for new subparts NSPS OOOOb and EG OOOOc. The commenter strongly supports the issuance of a supplemental proposal, and respectfully urges EPA to make the scope of that supplemental proposal, and the subjects on which it solicits comment, as broad as possible.

Because the regulated community has not yet had a chance to review and comment on proposed rule language, the commenter (0777-Ascent) urges EPA in its supplemental proposal to change

the proposed applicability date for sources that will be subject to the new NSPS OOOOb from November 15, 2021 (the date of publication in the *Federal Register* of the November 2021 Proposal) to the date of publication of the supplemental proposal that includes actual proposed rule language. CAA section 111(a)(2), 42 U.S.C. § 7411(a)(2), provides that a “new source” is any source whose construction or modification begins “after the publication of . . . proposed regulations prescribing a standard of performance under this section which will be applicable to such source.” The CAA does not define the term “proposed regulations.” It is at best doubtful whether, with respect to the proposed new NSPS OOOOb and EG OOOOc, the November 15, 2021, publication constitutes “proposed regulations” within the meaning of the statute, as that publication does not propose any regulatory text with respect to these proposed new subparts. The commenter states that the approach EPA has taken, under which it proposes to subject new sources (*i.e.*, those that commence construction or modification after November 15, 2021) to regulatory requirements whose regulatory text it has not yet proposed, creates considerable uncertainty for companies that may wish to construct or modify sources but cannot reasonably predict what specific requirements such sources will be subject to under the proposed new subparts.

For this reason, the commenter (0777-Ascent) states that EPA should in the supplemental proposal propose an applicability date for proposed new NSPS OOOOb and EG OOOOc that is the date of publication of the supplemental proposal (assuming that the supplemental proposal contains proposed regulatory text for these subparts). Failing to do so may render the eventual final rule legally vulnerable in this regard. Should EPA decide not to delay NSPS OOOOb applicability to the date that the proposed regulations are published, the commenter urges EPA at a minimum to account for the gap that failing to change this date would create between the “trigger” date for new sources and the date at which regulated companies see proposed regulatory text by providing a longer period to come into compliance, to include a phasing-in of regulatory requirements through a series of compliance dates, similar to the approach taken in the 2016 adoption of NSPS OOOOa.

Commenter (0814-IPAA *et al.*) states that the 154 pages of *Federal Register* text contained no proposed regulatory language. The commenter asserted that the “proposed rule” is not a proposed rule and is at best an ANPR. The commenter notes that the applicability date (the requirements of the NSPS apply to any sources constructed or modified after a certain date) is the date the NSPS are proposed and published in the *Federal Register*. As indicated above, however, the November 15, 2021, publication in the *Federal Register* did not contain proposed regulatory language. Thus, the commenter contends that, for EPA to require all new or sources modified after November 15, 2021, as subject to drafted regulations that were not yet drafted is arbitrary and capricious.

Commenter (0808-API) states that the November 2021 Proposal cannot set the new source trigger date under NSPS OOOOb because regulatory text is missing. EPA proposes that the new source trigger date for NSPS OOOOb is November 15, 2021, the date the Proposal was published in the *Federal Register*. The commenter appreciates EPA’s promise to make proposed regulatory text available in an upcoming supplemental proposal, but they assert that such a promise is not sufficient to set the new source trigger date at November 15, 2021.

Commenter (0808-API) states that the lack of proposed regulatory text creates an insurmountable practical problem. Affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. Affected facilities can only surmise what the rule would require based on the description and explanation provided in the preamble. But affected facilities cannot know with sufficient clarity what would be required under the Proposal because they cannot see the part of the proposal that matters most – the regulatory text that would establish the binding legal obligations that would be imposed under the proposal.

Commenter (0808-API) suggests that the lack of regulatory text means that the November 2021 Proposal does not give fair notice to potentially affected facilities of what requirements they might be required to meet upon the effective date of the final rule. Fair notice is only achieved when EPA provides regulated entities with sufficient detail of what exactly will be required, which it has not done here.

Commenter (0808-API) also states that the publication date of the November 2021 Proposal does not set the trigger date because it is not a proposed “regulation.” CAA section 111(a)(2) defines “new source” to mean “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” CAA section 111(a)(2) (emphasis added). Thus, only a proposed “regulation” may set the new source trigger date.

Commenter (0808-API) states that the preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a “rule.” Although the current preamble describes the type of regulatory requirements that EPA proposes to eventually promulgate, the preamble is not in and of itself a document that establishes the “agency statement of general or particular applicability and future effect.” That type of required statement would be established only by the proposed regulatory text, which is absent here. Thus, the November 2021 Proposal cannot establish the new source trigger date because it does not include a proposed rule. The new source trigger date is tied to the date proposed regulatory text is published in the *Federal Register*.

As a last note, the commenter notes that CAA section 307(d) administrative rulemaking procedures do not expressly require a proposed rule to include proposed rule text. Commenter (0808-API) does not opine on the question of whether a proposed rule subject to CAA section 307(d) provides adequate public notice and an opportunity to comment if it does not include or make available proposed rule text. But that issue, according to the commenter, is beside the point here because the new source trigger date is defined in CAA section 111(a)(2) and not in CAA section 307(d). So, even if the current proposal satisfies the procedural requirements of CAA section 307(d), the commenter states it does not set the new source trigger date for the reasons they explained above.

Commenter (0722-MDNR) states that the November 2021 Proposal does not include any proposed regulatory text. The preamble and the RIA for the November 2021 Proposal provide some level of specificity in what EPA is proposing. However, without seeing the regulatory

requirements or the EGs as they are proposed to appear in the Code of Federal Regulations, it hinders the commenter's ability to review the impact of the November 2021 Proposal and provide meaningful comments during the public participation process. The November 2021 Proposal indicates EPA is planning to submit a supplement to this proposed rule, and the commenter encourages strong state/federal engagement as the requirements are further refined and specified. The commenter recommends EPA reach out to states to conduct webinars and workshops to offer information and gather input on the contents of the supplement before it is proposed. Then once EPA proposes the supplement, it should allow adequate time for the public review and comment period, with a minimum of 60 days, but preferably longer depending on the complexity and scope of the supplement.

Commenter (0831-AXPC) urges EPA, in its supplemental proposal, to change the applicability date for sources that will be subject to the new NSPS OOOOb from November 15, 2021 (the date of publication in the *Federal Register* of the November 2021 Proposal) to the date of publication in the *Federal Register* of the supplemental proposal, which will, apparently, also be the date on which EPA will first propose regulatory text for the new NSPS OOOOb and EG OOOOc.

The commenter's (0831-AXPC) position is that EPA does not have authority under CAA section 111 to define a "new source" for a standard other than by reference to the date of publication of proposed regulatory text for that standard. Additionally, the commenter states that even if EPA had legal authority to proceed in this manner, the commenter believes there are strong policy and equity reasons why it is not appropriate for EPA to do so (arguments provided below):

First, as regards EPA's legal authority to proceed in this manner: Clean Air Act (CAA) Section 111(a)(2) (42 United States Code (U.S.C.) § 7411(a)(2)), provides that a "new source" is any source whose construction or modification begins "after the publication of . . . proposed regulations [] prescribing a standard of performance under this section which will be applicable to such source." The CAA does not define the term "proposed regulations." However, with respect to the new subparts OOOOb and OOOOc, the Initial Methane Notice does not appear to constitute "proposed regulations . . . prescribing a standard" within the meaning of the statute, as that publication does not propose regulatory text with respect to these new subparts.

The approach EPA has taken, under which it purports to subject new sources (*i.e.*, those that commence construction or modification after November 15, 2021) to regulatory requirements whose regulatory text it has not yet proposed, creates considerable uncertainty for companies that may wish to construct or modify sources but cannot reasonably predict what specific requirements such sources will be subject to under the new subparts. For this reason, EPA should, in the supplemental proposal, propose an applicability date for new subparts OOOOb and OOOOc of the date of publication of the supplemental proposal (assuming that the supplemental proposal, unlike the November 2021 Proposal, contains proposed regulatory text for these subparts).

Second, even if EPA had legal authority to proceed in this manner, it is unsound as a matter of policy, and inequitable. The plain purpose of Congress defining a new source as one whose construction or modification begins after proposal of regulations is that this

sequence allows owners and operators to understand their proposed regulatory obligations when they make decisions whether to break ground on new facilities or modify existing facilities—so that they know, not only whether a source constructed or modified after a date certain will be treated as a new source, but also the details of the regulatory obligations that will be incurred by a source deemed new. Because EPA has not yet proposed regulatory text for new subpart OOOOb, Congress’s purpose is not fulfilled if EPA deems sources to be new whose construction or modification begins after November 15, 2021.

In addition to EPA’s approach not fulfilling Congress’s purpose in enacting 111(a)(2), it also threatens to unjustly penalize owners and operators who have been making and will continue to make choices in good faith as to whether and how to construct or modify their facilities without the benefit of proposed regulatory text.

Finally, even if EPA does not in its supplemental proposal change the date defining a new source from November 15, 2021 to the date of publication in the *Federal Register* of the supplemental proposal and proposed regulatory text—which, for the reasons given above, it should—AXPC urges EPA at a minimum to account for the gap that failing to change this date would create between the “trigger” date for new sources and the date at which regulated companies see proposed regulatory text by providing a longer period to come into compliance, to include a phasing-in of regulatory requirements through a series of compliance dates, similar to the approach taken in the 2016 [NSPS] OOOOa rule.

Commenter (0911-NDPC) states that reviewing and developing meaningful comments is difficult and inefficient when EPA does not include the actual proposed rule text. The commenter adds that EPA should not consider the November 2021 publication a proposed rule without the rule text. The commenter adds that they do not believe the November 2021 action meets the requirements of a proposed rule for rule making, and the proposed applicability date for sources that will be subject to the new NSPS OOOOb and EG OOOOc should not be November 15, 2021, but rather the date the actual proposed rule text is published.

Commenter (0817-GPA) states that the November 2021 Proposal does not include proposed regulatory language. This deprives regulated industries of fair notice regarding what EPA is actually proposing and inhibits their ability to effectively comment on the Proposal. Further, it raises significant concerns regarding the effective date. EPA should clarify that, as there are no proposed regulations, the effective date should be, at the earliest, when EPA publishes a supplemental proposed rule that includes proposed regulatory text.

As an initial matter, the commenter (0817-GPA) suggests EPA make clear that the NSPS OOOOb regulations shall not be effective before EPA publishes the regulatory text. Without proposed regulatory text, no stakeholder can provide complete comments on the proposed NSPS OOOOb (or EG OOOOc) regulations. The commenter provides that EPA’s November 2021 Proposal only includes preamble language describing what EPA intends to propose, but states that it “plans to propose the regulatory language for NSPS OOOOb and EG OOOOc through a supplemental action.” 86 Fed. Reg. at 63,124. Although the preamble provides basic concepts, the commenter cannot understand or comment fully on the details of EPA’s proposed regulations

until EPA publishes the actual regulatory language. According to the commenter, such details are absolutely essential for understanding what will be a highly technical rule. Given the absence of such details, and EPA's stated plans to provide regulatory language through a supplemental notice, the November 2021 Proposal must be considered, in effect, an ANPR for a yet to be proposed NSPS OOOOb, with the actual proposal – and a separate public comment period that provides a full and fair opportunity for public comment – to come sometime in the future.

Commenter (0817-GPA) states that any other approach would be inconsistent with the explicit direction of Congress. Under 42 U.S.C. § 7411, a “new source” is defined as one where construction or modification commences “after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance....” (emphases added). Thus, the statutory trigger is clearly “regulations,” not a general preamble discussion lacking the actual regulatory text but, instead, promising that the regulatory text will be forthcoming. This correction is necessary, as the commenter asserts that the November 2021 Proposal erroneously suggested that NSPS OOOOb would be applicable after November 15, 2021.

Even aside from the express statutory requirement, the commenter (0817-GPA) suggests that imposing an effective date before regulatory text is presented would be wholly impractical and grossly unfair to regulated parties. Without regulatory text, owners and operators cannot know how to design and construct “new” sources in accordance with the rule. A preamble cannot, and does not, provide the technical details required to design and construct compliant sources or to properly structure the monitoring and recordkeeping programs required. Further, owners and operators do not know when new sources must be constructed. Hence, the commenter states that, at the earliest, a source could become “new,” and subject to new regulations, only upon EPA's publication of the “regulations.” The commenter urges EPA to tie the effective date to any final rule, given the extraordinary complexity and scope of the new regulatory scheme that EPA apparently expects to publish in its supplemental proposal. Deferring the effective date would allow the public comment process to be completed and provide parties with a greater degree of certainty before triggering the investments a new NSPS OOOOb would entail. Regardless, EPA must—at the very least—make clear that the “new source” effective date will not occur until, at the earliest, it publishes a supplemental proposed rule that includes the proposed regulatory language.

Commenter (0921-USCC) requests that EPA amend the applicability date for the NSPS OOOOb to the publication date of the anticipated supplemental proposal, which will presumably include regulatory text sufficient to trigger applicability.

Commenter (0755-TPA) suggests that the applicability date of new NSPS OOOOb be extended to the publication date of the proposed rule language. EPA has chosen in this instance to pursue an unusual rulemaking process: issuing a proposal that does not include the actual rule language that would be contained in the Code of Federal Regulations. Specifically, EPA's November 15, 2021, *Federal Register* notice consists of 154 pages of preamble and no formal regulatory text.

EPA nonetheless proposes to base the applicability date of the new NSPS OOOOb on the November 15, 2021, preamble publication date. Commenter (0755-TPA) believes that this approach to rulemaking is inappropriate. The provisions of Part 60, including any new or revised



performance standard promulgated under CAA section 111 (b), apply to “an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.” The “proposed standard” is the actual rule language, not EPA's prefatory description and explanation- and in some cases, EPA's prediction- as to what that rule language might ultimately look like. In the world of complex regulations, emission limits, and compliance, the details are everything. The commenter suggests that a company determining whether, and to what extent, a particular operation is covered by a performance standard may gain some insight or coloration from a preamble, but in the last analysis it is the precise rule language itself that is always carefully scrutinized in order to resolve questions of applicability and required compliance. The key is what the formal rule text says. Yet the commenter states that they currently do not have the benefit of the actual proposed rule language with which their members must ultimately comply. Indeed, the commenter notes that EPA indicates that additional rulemaking, clarifications, modifications are still to occur. The commenter contends that the current NSPS OOOOb proposal is more in the nature of an ANPR than a rule proposal, and as such it is inappropriate to base the applicability date on the November 15, 2021, publication date.

In this setting, the commenter (0755-TPA) states that a company cannot proceed with any sort of confidence as to how the rules might ultimately read. Requiring compliance based on a construction or modification date that is months earlier than the publication of actual proposed rule language - *i.e.*, the “proposed standard” described by 40 CFR 60.1(b)- would be unfair and contrary to EPA's own rules, and to proceed in this way would potentially trigger future litigation. The commenter urges EPA to base the applicability dates in these rules on the date of *Federal Register* publication of actual rule language, as it has traditionally done, not a preamble description of such language.

Commenters (0599-Marcellus Shale Coalition (MSC), 0739-Citation Oil & Gas Corp. (Citation), 0787-Atmos Energy Corporation (Atmos), 0802-Kraken Oil & Gas LLC (Kraken), 0820-Pioneer) request that the effective date for the proposed regulation not be established until the actual draft regulatory text is proposed and published for public review. Commenter (0599-MSC) states that the November 2021 Proposal provides varying degrees of detail describing what EPA plans to propose in a supplemental regulatory action, which not only makes commenting on the regulation extremely difficult, but also places an effective date on new construction and modifications which are in various stages of implementation, such as having a completed design or being ready to commence construction imminently. Commenter indicates that many of these projects will have to wait for this supplemental proposal to determine if they include an affected source and applicable NSPS requirements and notes that regulatory language for these determinations will not be available for at least several months, possibly after implementation.

Commenter (0802-Kraken) requests that EPA align the rule applicability dates with the publication of the supplemental proposal and actual proposed rule language to minimize duplicative requirements and conflicts with compliance dates. The commenter states that there is a chance this rule could have multiple compliance dates based on both the November 2021 Proposal and on the supplemental proposal. The commenter asserts that if the applicability

compliance date is not associated with the proposed supplemental rule, affected facility determinations would be based on a rule proposal and not actual proposed rule language, bringing into question the rule's interpretations and compliance under the CAA.

Commenter (0820-Pioneer) notes that CAA section 111(a)(2) provides that a “new source” is any source whose construction or modification begins “after the publication of . . . proposed regulations [] prescribing a standard of performance under this section which will be applicable to such source.” The commenter states that the CAA does not define the term “proposed regulations,” but the commenter asserts that with respect to the proposed new NSPS OOOOb and EG OOOOc, the November 2021 publication does not appear to constitute “proposed regulations ... prescribing a standard” within the meaning of the statute, as that publication does not propose any regulatory text with respect to these proposed new subparts. The commenter believes that the approach EPA has taken, under which it proposes to subject new sources (*i.e.*, those that commence construction or modification after November 15, 2021) to regulatory requirements whose regulatory text it has not yet proposed, creates considerable uncertainty for companies that may wish to construct or modify sources but cannot reasonably predict what specific requirements such sources will be subject to under the proposed new subparts. For this reason, the commenter states, EPA should, in the supplemental proposal, propose an applicability date for proposed new NSPS OOOOb and EG OOOOc of the date of publication of the supplemental proposal. The commenter believes that failing to do so may render the eventual final rule legally vulnerable. If EPA does not do this, the commenter urges EPA to account for the gap between the “trigger” date for new sources and the date at which regulated companies see proposed regulatory text by providing a longer period to come into compliance, to include a phasing in of regulatory requirements through a series of compliance dates, similar to the approach taken in the 2016 NSPS OOOOa rule.

Response I-23-2: See discussion in section IX.A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the Final Rule preamble related to applicability of the requirements under the proposed rules.

Comment: Commenter (0424-Division of Air Quality, West Virginia Department of Environmental Protection (WVDEP)) asks two questions regarding applicability:

- For affected existing sources constructed on or before November 15, 2021, that will be designated facilities under the EG of 40 CFR part 60, subpart OOOOc, will they continue to also be subject to the NSPS of 40 CFR part 60, subparts OOOO or OOOOa, as applicable?
- Will designated existing facilities under 40 CFR part 60, subpart OOOOc (EG) continue to be subject to 40 CFR part 60, subpart KKK? Please clarify if both the 40 CFR part 60, subpart KKK VOC standards will apply and the 40 CFR part 60, subpart OOOOc (EG) presumptively approvable methane standards will apply to these facilities, or if 40 CFR part 60, subpart KKK will no longer apply, and these sources will be regulated by the state under 40 CFR part 60, subpart OOOOc. If the sources will be subject to regulation under both subparts, has the EPA reviewed these subparts such that the sources will not be subject to conflicting requirements and that the requirements are streamlined?

Similarly, commenter (0924-U.S. Small Business Administration (SBA)) states that small entities have expressed significant confusion and concern about how sources that were new, modified, or reconstructed between August 23, 2011, and November 15, 2021, will be regulated because these sources are subject to direct EPA regulation under prior NSPS, subparts OOOO or OOOOa, and these same sources would be covered by the proposed EG subpart OOOOc to be regulated under state law. The commenter indicates that this situation has the potential to create duplicative regulatory requirements, multiple enforcement authorities, and significant unnecessary costs for small businesses. The commenter recommends that EPA propose that states can obtain an explicit exemption for existing sources from the prior NSPS subparts; under this exemption, states would incorporate the performance standards of NSPS OOOO and OOOOa for these sources into their performance standards under the EG. The commenter notes that such an exemption would reduce the number of different regulatory provisions to which they are subject and clearly identify the regulatory authority for their sources.

Response I-23-3: See discussion in sections IX.A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?), IX.B (What date defines an existing source for purposes of the final EG OOOOc?), and IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa?) of the Final Rule preamble.

Comment: Commenter (0922-National Association of Manufacturers (NAM)) states that EPA should take steps to reduce the likelihood that efforts to comply with the final EG independently trigger requirements under the CAA's New Source Review provisions for any air pollutant.

Response I-23-4: See discussion in section XV (Prevention of Significant Deterioration and Title V Permitting) of the preamble to the final rule regarding the applicability of permitting requirements.

### **23.3 Lack of Regulatory Text**

Comment: Several commenters (0193-National Federation of Independent Business (NFIB), 0599-MSC, 0743-WEA, 0750-Flogistix, 0793-PBPA, 0802-Kraken, 0824-Wyoming Department of Environmental Quality (WDEQ), 0836-Domestic Energy Producers Alliance (DEPA), 0910-Attorney General of Louisiana (AG LA) *et al.*, 0929-NSWA, 0938-TXOGA, 0946-Michigan Oil and Gas Association (MOGA), 0957-Wyoming Coalition of Local Governments (WYCLG), 1391-INGAA, 1341-PGCC *et al.*, 375-Kinder Morgan, 1391-INGAA) express that the November 2021 Proposal, because it did not contain proposed regulatory text for NSPS OOOOb and EG OOOOc, and/or did not meet the requirements as a proposed rule under the APA, does not represent a proposed rule. Several of these commenters (0193-NFIB, 0836-DEPA) recommended that EPA withdraw the November 2021 Proposal. Examples of some of the comments received are provided in the following paragraphs.

Commenter (1391-INGAA) suggests that the lack of regulatory text makes comment on certain aspects of the November 2021 Proposal difficult, if not impossible, because it is unclear what EPA intends to do. For example, the commenter states that in numerous places in the November 2021 Proposal, EPA discusses the regulation of emissions from wells, but it is unclear whether

EPA intends to regulate production wells, storage wells, or both. In Table 2 of the November 2021 Proposal, EPA lists “well liquids unloading” as an affected source and proposes a best system of emissions reduction (BSER) of zero methane or VOC emissions. This BSER can be applied only at hydraulically fractured wells. According to the commenter, it is possible that EPA understands this and intends that this performance standard apply only to hydraulically fractured wells, but without the proposed regulatory text, the commenter’s members have no way of confirming that. The commenter adds that the issue of what type of wells certain proposed standards of performance apply to is a core, fundamental issue, and without knowing this with certainty, the commenter’s members cannot evaluate the proposal and provide EPA with meaningful feedback. Without clear definitions being provided, the commenter argues that it is impossible to understand the scope of the November 2021 Proposal. The commenter provides several examples where it was necessary for them to have greater detail in the form of regulatory text to properly comment (*e.g.*, NSPS and EG proposed compliance timelines, EG state plan requirements).

Commenter (0750-Flogistix) states that they support the Agency's utilization of performance-based standards. However, they note that, by not publishing regulatory text to support the “standards of performance,” EPA demonstrates that these rules have not been fully developed and require significant additional work. By indicating that EPA will later publish a “supplemental proposal” with regulatory text, the commenter contends that the Agency is creating confusion and uncertainty.

Commenter (0193-NFIB) states that the 153-page notice is all preamble and no proposed rule; the notice fails to contain the text of proposed rules. Nevertheless, to the extent the notice describes or refers to proposed rules, the commenter recommends that EPA withdraw them.

Commenter (0836-DEPA) agrees with the Producers Associations comments that the November 2021 proposed rule is at best a notice of proposed rulemaking as a data gathering exercise. The commenter states that the 153 of *Federal Register* text contains no proposed regulatory language. The commenter notes that the comments provided by Producers Associations stated that, “[t]here is no statutory deadline forcing a truncated comment period.

Commenter (0938-TXOGA) suggests that the November 2021 Proposal contains no regulatory language specifying the requirements that would apply to these sources under NSPS OOOOb. To be sure, this approach creates significant uncertainty for regulated sources, but it also is inconsistent with the CAA “new source” definition and Congress’s underlying intent in creating this definition in the statute. The CAA defines a “new source” as “[a]ny stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” Under this statutory definition, it is clear that application of “new source” standards occurs only where a source undertakes construction or modification after the publication of “regulations” or “proposed regulations” prescribing a standard of performance applicable to the source.

Commenter (0938-TXOGA) suggests the November 2021 Proposal cannot be reasonably construed as a “proposed regulation” (or a proposed “rule,” to use the APA term) because the

Proposal lacks sufficient specificity to reflect any “design to implement, interpret, or prescribe law or policy.” In the Proposal, EPA sets forth conceptual standards that it is considering for affected facilities under NSPS OOOOb but notes that more specific requirements will be issued in a supplemental proposal to “provide regulatory text.” This forthcoming proposed “regulatory text” will constitute the “proposed regulations” for NSPS OOOOb; thus the publication date of the supplemental proposal would be the earliest triggering date for NSPS OOOOb applicability allowed under CAA section 111. The commenter contends that this conclusion is further supported by statements in the preamble that indicate EPA may be regulating beyond that which is identified in the Proposal. For example, EPA states in Section II.A, “Does this action apply to me?” that for regulated entities to determine if they are covered by the regulation, “you should carefully examine the applicability criteria found in the final rule.” But commenters need to examine the applicability in the proposed rule to provide comment. The commenter asserts that is the purpose of a proposed rule.

Commenter (1375-Kinder Morgan) notes that that EPA has advanced its NSPS OOOOb and EG OOOOc proposals without rule language. In this way, the commenters states that the proposals are more akin to an ANPR, making fulsome comment on the proposals at this time, difficult. The APA requires that an agency’s proposed rule must provide “either the terms or substance of the proposed rule or a description of the subjects and issues involved.” EPA states that it “plans to issue a supplemental proposal and supplemental [RIA] for the supplemental proposal to provide regulatory text for the proposed NSPS OOOOb and EG OOOOc.” At present, however, the commenter states that the November 2021 Proposal has been issued without regulatory text, leaving much of the “terms [and] substance” open to interpretation. The commenter, therefore, reserves the right to supplement and modify these comments upon review of any subsequently published proposed regulatory text. Given the significant nature of these preliminary proposals, the commenter encourages EPA to continue dialogue with operators to ensure adequate opportunity for review and comment on any draft rule language is afforded.

Commenter (0824-WDEQ) states that the November 2021 Proposed Rule does not meet the notice requirements of § 4 of the APA. 5 U.S.C. § 553(b). The commenter adds that section 553 of the APA requires agencies to provide public notice of a proposed rulemaking in a way that is “adequate to afford interested parties a reasonable opportunity to participate in the rulemaking process.” *Florida Power & Light Co. v. United States*, 846 F.2d 765, 771 (D.C. Cir. 1988); see also SENATE JUDICIARY COMMITTEE, ADMINISTRATIVE PROCEDURE ACT, S. REP., No. 752, 77th Cong., 1st Sess. 14 (1945) (“Agency notice must be sufficient to fairly apprise interested parties of the issues involved, so that they may present responsive data or argument relating thereto”). The commenter explains that this notice requirement is designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review. *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 547 (D.C. Cir. 1983), *MCI Telecomm. Corp. v. FCC*, 57 F.3d 1136, 1142 (D.C. Cir. 1995).

Commenter (0824-WDEQ) adds that here (under the November 2021 proposal), the agencies have not actually proposed a rule. The commenter states that the proposal lacks any regulatory language or specific requirements, which made it impossible for the commenter to fairly

comment on the substance of the proposal or to assess the scope of its impacts. According to the commenter, the lack of proposed regulatory language, coupled with EPA's 31-page comment solicitation requests about preamble language, is unfair and unlawful. The commenter asserts that EPA must provide substantive and specific regulatory language for comment in conjunction with the preamble in a future proposed rulemaking before it attempts to promulgate a final rule.

Commenter (0824-WDEQ) states that the proposed rule's ambiguity and lack of specific, binding requirements - as well as its solicitation of additional comments on emissions sources and definitions that are not even addressed in the proposed rule, such as abandoned wells, pigging operations and related blowdown activities, and control device efficiency and operation, prevents a full assessment of the complete scope of its impacts. It is quite clear to the commenter, however, that the revised requirements pertaining to NSPS OOOOa, and especially the newly introduced NSPS requirements in NSPS OOOOb and EG OOOOc, would significantly impact Wyoming.

Commenter (0824-WDEQ) states that the proposed rule is opaque, expansive, and lacks specific requirements. The commenter adds that the fact that EPA is soliciting comment on extended areas to regulate in effect transforms a single proposed rule into several different rulemakings; it is far too broad in its scope for a complete assessment. The commenter believes that the document, as written, more closely resembles an ICR or an ANPR than a proposed rule - and a formal period of assessment was not provided. The commenter states that EPA should have performed more outreach with individual oil and gas producing states, such as Wyoming, before promulgating the proposed rule. By not doing so, the commenter believes that EPA missed out on obtaining AQD's extensive knowledge and practical experience on the control and management of methane and other emissions and controls for the oil and gas sector.

Commenter (0824-WDEQ) believes this overarching concern applies to all of the subsequent concerns that are raised. Simply put, the commenter provides that states like Wyoming that will experience significant impacts and cumbersome requirements as a result of the proposed rule cannot reasonably assess the rule in its entirety. In turn, they assert that EPA should have directly engaged with states and given states significantly more time and input by way of an ANPR or ICR, followed by a proposed rule containing more regulatory specificity. According to the commenter, EPA's failure to follow this procedure not only jeopardizes the legal defensibility of the rule, but it represents a missed opportunity for valuable collaboration.

Commenter (0957-WCLG) states that the APA requires that a NPRM include "either the terms or substance of the proposed rule or a description of the subjects and issues involved." 5 U.S.C. § 553(b)(3). The commenter goes on to say that EPA is asking for comments on the potential for establishing standards for abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations. 86 Fed. Reg. at 63240. The commenter notes that EPA admits that it does not have enough information to quantify and evaluate BSER or NSPS for these systems and, therefore, is not proposing NSPS or EG at this time. This commenter continues by stating that the solicitation of comments is not appropriately included within this notice of proposed rulemaking because it fails to provide an adequate description of the issues involved or terms or substance of a proposed rule. The commenter argues that this

request for additional information on other sources of emission should instead be its own separate rulemaking, starting with an ANPRM to obtain the necessary information.

Commenter (0793-PBPA) states that the November 2021 Proposed Rule does not contain regulatory text. The commenter notes that the proposal indicates that EPA will later publish a “supplemental proposal.” The commenter suggests that, by publishing this proposal without providing the regulated community any regulatory text, EPA has demonstrated that the proposal has not been fully developed and requires significant additional work. Instead of providing the regulated community with proper notice of how it will be regulated, the commenter states that EPA provided a proposal—covering hundreds of thousands of sources—that lacks clarity and creates uncertainty.

Commenter (0793-PBPA) recommends that once EPA publishes the proposed regulatory text, the public should have a minimum of 90 days to review it. The commenter states that they would oppose efforts to promulgate the rule in such a way as to circumvent public input and comment (e.g., through publication of an interim final rule).

Commenter (0802-Kraken) states that EPA published these actions as a “proposed rule” without actual proposed rule language. The commenter sees the November 2021 proposed rule as more of an ANPR in that the published document is soliciting feedback on topics and emission sources with specific associated issues in the same manner as previous EPA rulemaking information collection requests. The commenter posits that publishing proposed actions not yet defined, along with a solicitation for feedback on the addition of regulated sources, creates regulatory and financial uncertainty for the regulated community.

Commenter (0910-AG LA *et al.*) believes that just as other commenters have noted, the Methane Notice is not a NPRM. Despite its length, the so-called “proposed rule” contains no proposed regulatory text. Nor does it put parties on notice of what the final rule will contain. Without such specific and clear proposed regulatory text, the Notice must be considered an ANPR; it does not adequately provide notice to the public of what precisely is being proposed. See 5 U.S.C. §553(b) (“The notice shall include ... either the terms or substance of the proposed rule or a description of the subjects and issues involved.”). Accordingly, before a final rule can be promulgated, the commenter argues that EPA must publish a full notice of proposed rulemaking that includes specific, clear proposed regulatory text.

Commenter (0946-MOGA) believes that the proposed regulations on November 15, 2021, did not offer a specific regulatory framework or text. Small business entities with minimal staff and limited resources need direct, well-defined, and easily understood proposed regulations to evaluate for impacts and provide meaningful comment. Further, approximately 1000 pages of preamble and technical service documents were published by EPA with a limited response time of 77 days encompassing two major holidays. The commenter asserts that this significantly prevented many of the commenter’s constituents from fully deciphering and commenting on the potential short-term and long-term implications of proposed regulations.

Commenter (0929-NSWA) states that the 153 pages of *Federal Register* text contains no proposed regulatory language. The commenter asserts that the “proposed rule” is not a proposed

rule, at best, it should be considered in the form of what experienced observers of federal regulatory practices would view as an ANPR. The commenter believes that it is particularly concerning that the released preamble language – without regulatory text included as mentioned previously – is not well-formed and yet the agency is still seeking a significant number of comments. The commenter states that this is occurring in the context of a demonstrated lack of full input from regulated parties about how the regulations will impact their business and the challenges with implementing EPA’s proposals, both operationally and financially. For example, they note that small business operators will disproportionately realize the impact of short development time of this regulation due to fewer available resources to digest and translate the requirements into actionable programs.

Commenter (0929-NSWA) believes EPA should have been collecting additional input from stakeholders which most likely would have reduced the number of times that EPA solicited input in the proposed regulation and would have provided the regulated community with more certainty in what the final regulation will look like.

Thus, the commenter (0929-NSWA) suggests it is likely the regulatory text, whenever it is issued, will leave efforts to address methane and improve the environment in a weaker, not stronger, position. The commenter states that one very tangible example of this likely outcome in the forthcoming rule is reflected in the preamble, where EPA stated that they are considering including additional sources as affected facilities that would be regulated for methane emissions. These sources include standards for abandoned and unplugged wells, pipeline pigging and related blowdown activities, and tank truck loading operations. The commenter is concerned that EPA has not spent sufficient time developing the regulation to determine if these operations should be included in the regulation or should be omitted. The commenter believes that there is currently insufficient data to support developing new regulations for the proposed sources. The commenter asserts that EPA needs to collect an appropriate volume of data and engage industry stakeholders prior to developing new regulations for the sources.

Commenter (1391-INGAA) states that the absence of proposed regulatory text makes it difficult to provide meaningful comments on November 2021 proposed NSPS OOOOb and proposed EG OOOOc. They add that EPA’s failure to provide the proposed regulatory text is unusual and is inconsistent with the intent of the APA. The commenter urges EPA to follow through on its plan to issue a supplemental proposal with the proposed regulatory text. The commenter states that they will submit comments on the supplemental proposal and the proposed regulatory text and asks EPA to allow sufficient time (*i.e.*, at least 90 days) for preparation of comments on that proposal. In the absence of the regulatory text, commenting on certain aspects of the Proposed Rule is difficult—if not impossible. For example, the commenter states that it is unclear in several places what type of wells EPA intends to regulate in certain situations.

Commenter (1391-INGAA) asserts that EPA’s failure to provide the proposed regulatory text is unusual and is inconsistent with the intent of the APA. As EPA notes in the Proposed Rule, it “plans to issue a supplemental proposal and supplemental [regulatory impact analysis (RIA)] for the supplemental proposal to provide regulatory text for the proposed [NSPS] OOOOb and ... [EG] OOOOc.” EPA states that it views this “[a]s a further step in the rulemaking process” and will be “solicit[ing] additional public input” at that time. As a result, these portions of the



Proposed Rule do not include rule language and are more akin to an ANPR, and as discussed further below, it makes meaningful comment on certain aspects of the Proposed Rule impossible.

Commenter (1391-INGAA) states that it is highly unusual for an agency to purposefully exclude proposed regulatory language in a proposed rule, especially one of this magnitude. The commenter adds that the APA requires that an agency's proposed rule must provide "either the terms or substance of the proposed rule or a description of the subjects and issues involved." Courts have interpreted the notice requirement of the APA to require that a final rule be a "logical outgrowth" of the proposed rule. The commenter notes that the issue of whether or not mere vague discussion of the issues involved is sufficient to satisfy the logical outgrowth test has not yet been decided by the courts.

Commenter (1391-INGAA) urges EPA to follow through on its plan to issue a supplemental proposal and supplemental RIA along with the proposed regulatory text for NSPS OOOOb and EG OOOOc and further urges EPA to allow sufficient time for comment on these important documents. In particular, seeing the regulatory text is imperative as the specific words matter. As EPA knows, the commenter states that how a statute or a regulation is interpreted by courts and by EPA can be affected by such benign things as the placement of a comma or a word as seemingly innocuous as "any." The commenter provides several examples where they note that it was essential for them to see the regulatory text in order to be able to provide comment. The commenter states that they look forward to reviewing the proposed regulatory text once it becomes available and asks the Agency to provide a reasonable amount of time for comment on that text and all related aspects of the Proposed Rule as it will likely give rise to many new issues that cannot be identified now in the text's absence.

Response I-23-5: The EPA has responded to concerns about proposed regulatory text, and applicability in the preamble for the final rule. The December 2022 Supplemental Proposal included proposed regulatory text for both the NSPS OOOOb and EG OOOOc.<sup>4</sup> Similar comments were also provided on the December 2022 Supplemental, see Volume II, Chapter 23 (Miscellaneous Other Comments), subsection 23.6 (Regulatory Text), Response II-23-26 for response to those comments.

### **23.4 Request for Clarification of the Applicability/Requirements of the Differing NSPS OOOOa/OOOOb/OOOOc Rules**

Comment: Commenter (0820-Pioneer) recommends that EG OOOOc be relative to NSPS OOOOa and as such, the applicability date for EG OOOOc be pre-2015 instead of pre-2021. As this rule is proposed, the six or so years of "new sources" under NSPS OOOOa (applicability date of September 2015), will now potentially be captured under EG OOOOc as "existing sources". The commenter notes that this would result in individual affected facilities such as compressors, certain pneumatic controllers, and fugitive emission components, among others, to be considered both a "new" and "existing" source under the CAA.

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<sup>4</sup> For the proposed NSPS OOOOb regulatory text, see Docket ID Number EPA-HQ-OAR-2021-0317-1551; for the proposed EG OOOOc regulatory text, see Docket Number EPA-HQ-OAR-2021-0317-1552.

Commenter (0820-Pioneer) states that notwithstanding the fact that these source categories and individual affected facilities within the source categories are covered under the same statute and covered under two separate, seemingly mutually exclusive sections, CAA 111(b) and 111(d), the definition and use of the term "existing source" in the CAA seems to clearly differentiate these sections. In 111(a)(6), EPA defines "existing sources" as "*any stationary source other than a new source,*" and CAA 111(d)(1)(A)(ii) provides that state plans for existing sources establish standards of performance for "any existing source for any air pollutant... to which a standard of performance under this section would apply *if such existing source were a new source.*" (emphasis added). The commenter asserts that the plain text of CAA 111, therefore, repeatedly draws a binary distinction between new and existing sources. According to the commenter, there is no sign that Congress intended EPA to regulate any source for the same pollutant simultaneously as both a new source under CAA 111(b) and an existing source under CAA 111(d).

Commenter (0820-Pioneer) requests that EPA explain the process and precedent for imposing two separate provisions that apply to two different categories of the same sources per definitions on 111 of the CAA.

Commenter (0820-Pioneer) requests clarification on how compliance would work in this scenario. For example, would there still be federal requirements under NSPS OOOOa to comply with as well as the EG OOOOc requirements that will presumably be developed under the state plan? The commenter suggests that would seem to result in duplicative record keeping a great deal of confusion. EPA should work to ensure that there is not duplicative reporting and recordkeeping requirements. For example, if a source is subject to both NSPS OOOOa and EG OOOOc, the source should be allowed to submit information to the state under EG OOOOc and be able to meet the reporting requirements for NSPS OOOOa. Please clarify.

Further, the commenter (0820-Pioneer) states that the vast majority of operators have taken extensive measures to comply with NSPS OOOOa in good faith and the EG OOOOc rules will likely impose more stringent requirements in the same sources which may require replacement and/or retrofitting certain equipment. The commenter explains that operators across the country have made certain decisions in well site and tank battery designs and equipment, and capital investments in reliance of NSPS OOOOa and in will potentially have to readdress and change these same sources for EG OOOOc. The commenter urges EPA to keep in mind that regulatory certainty is of vital importance to the oil and gas business functioning well economically and in an environmentally sound and compliant manner. The commenter adds that constant changes can result in a great deal of confusion, disrupt operations, such as delaying production and causing wells to be shut in prematurely, and even emission events while replacing and/or retrofitting, and impose an undue burden.

Response I-23-6: The EPA responded to concerns about applicability, including the potential for overlapping requirements in section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the final rule preamble.

Furthermore, the EPA disagrees with commenters that the EPA's definition of a "new" and "existing" source for purposes of this rulemaking is at odds with the statutory definitions. In this

final action, pursuant to CAA section 111(b)(1)(B), the EPA is promulgating new and updated standards in NSPS OOOOb that will apply to sources that construct after December 6, 2022, consistent with the statutory definition of “new sources” at CAA section 111(a)(2) which ties the applicability of an NSPS to the date of the proposed regulations prescribing the standards of performance. The term “existing source” is defined at CAA section 111(a)(6) in direct contrast as “*any stationary source other than a new source.*” Thus, relative to NSPS OOOOb being finalized in this rulemaking, an existing source is *any* source that would not be subject to NSPS OOOOb, i.e., any source constructed on or before (rather than after) December 6, 2022. This is further reinforced by the terms of 111(d)(1), which state that an EG promulgated under that provision applies to “*any existing source for any air pollutant . . . to which a standard of performance under this source would apply if such existing source were a new source.*” Consistent with this text, the EPA is promulgating OOOOc to apply to the same facilities that would have been subject to NSPS OOOOb if they had been constructed after December 6, 2022.

Moreover, the fact that some of these facilities may have been subject to the previously promulgated NSPS OOOOa does not undermine the EPA’s definition of an existing source relative to NSPS OOOOb. Nothing in the text of section 111 bars the EPA from regulating sources that complied with previous new source performance standards as “new sources” when newly constructed as “existing sources” after the EPA has promulgated updated new source standards after the source’s construction. Such sources meet the definition for an “existing source,” which broadly is defined as “any stationary source other than a new source.” Such sources are not, as the commenters contend, both “new sources” and “existing sources” of the same pollutant at the same time. Rather, after an emission guideline is issued, and a state or federal plan setting forth standards of performance is finalized, these sources are only existing sources. The commenters contend that their reading of section 111 means that any source that complied with a new source performance standard as a new source would never have to apply updated emission controls—they would only ever have to comply with the new source performance standard in place when they were newly constructed. That reading is untenable, and inconsistent with both the plain meaning of section 111 read as a whole, as well as with the broader purpose of the CAA. *See* CAA §101(b)(1) (The primary goal of the CAA is: “[T]o protect and enhance the Nation’s air resources so as to promote the public health and welfare and the productive capacity of its population.”). Application of that approach could have the perverse approach of permitting source that constructed decades prior consistent with now-outdated performance standards to avoid updating pollution controls even when more advanced and cost-effective control measures have become available, which cannot be reconciled with the statutory mandate to review standards every 8-years. This would frustrate the core purpose of section 111(b) and (d), which is intended to ensure that the standards of performance reflecting the “best system of emission reduction” are implemented for all sources (both new and existing). Further, regulating a source that complied with a new source performance standard when newly constructed as an “existing source” at a later point in time after the new source standards are updated is consistent with past agency practice. In the 2016 emission guideline for methane emissions from landfills, EPA likewise regulated landfills as existing sources even where those landfills had complied with a new source performance standard when constructed.

In response to comment that EPA keep in mind that constant changes can result in confusion, and disrupt operations, such as delaying production and causing wells to be shut in prematurely,

and even emission events while replacing and/or retrofitting, can impose an undue burden, the EPA acknowledges the commenter's concerns. The EPA has engaged with pertinent stakeholders regarding their concerns throughout the rulemaking process. Stakeholders have included, but are not limited to, industry, small businesses, tribal nations, and communities most affected by, and vulnerable to, the impacts of the rule. See discussion section VII (Summary of Engagement with Pertinent Stakeholders) in the final rule preamble. Input from all stakeholders were considered in the development of the final rule requirements, including industry concerns regarding the burden. See section X of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc requirements.

Comment: Commenter (0831-AXPC) is concerned that, under EPA's Initial Methane Notice, proposed in November 2021 some sources would be deemed both "new" and "existing" with respect to CAA 111 standards for methane. Specifically, sources whose construction or modification begins after September 18, 2015, and before November 15, 2021, would be "new" in that they are covered by NSPS OOOOa, and "existing" in that they will also be covered by new EG OOOOc. 86 Fed. Reg. at 63,117, Table 1 (Applicability Dates for Proposed Subparts Addressed in This Proposed Action). The commenter asserts that EPA does not have authority to take this approach under the statute. Even if it did, there is no environmental benefit to "pancaking" multiple layers of regulation on the same source, and there are compelling reasons of policy why EPA should not do so—in fact, doing so could be environmentally counterproductive (please note that this is separate and apart from commenter's position, as expressed elsewhere in these comments, that EPA cannot define a "new source" as one that begins construction or modification after the publication of the Initial Methane Notice, and that it should instead, in the supplemental proposal, set the determining date for new-source status at the eventual date of publication of that supplemental proposal, to include proposed regulatory text for new NSPS OOOOb and EG OOOOc).

First, the commenter (0831-AXPC) provides that CAA 111(d)(1)(A)(ii) provides that state plans for existing sources establish standards of performance for "any existing source for any air pollutant . . . to which a standard of performance under this section would apply if such existing source were a new source" (emphasis added). And CAA 111(a)(6) defines "existing source" as "any stationary source other than a new source" (emphasis). The commenter adds that the plain text of CAA 111, therefore, repeatedly draws a binary distinction between new and existing sources. The commenter states that there is no sign that Congress intended EPA to regulate any source for the same pollutant simultaneously as both a new source under CAA 111(b) and an existing source under CAA 111(d).

Second, the commenter (0831-AXPC) notes that even if EPA did have authority to proceed in this fashion, they believe that it would be either pointless or environmentally counterproductive to do so. Layering multiple sets of regulation to control the same pollutant does not provide enhanced environmental benefits, but it does create a highly confusing situation for owners and operators wishing to understand their compliance obligations. In fact, this "pancake" approach could actually lead to worse environmental outcomes. If owners and operators subject to a new-source regulation are faced with the prospect that EPA, at any future time, may also subject their new-source facilities to an existing source rule, that uncertainty will deter the owners and operators from innovating to comply with, and even do better than, the standards contained in the

new source regulation. The commenter states that CAA 111(b) is supposed to identify the best performance or work-practice standards and encourage their adoption to generally further the performance of the fleet of new sources. That purpose is thwarted under a duplicative, confusing, and extra-statutory approach like the one EPA suggests in the Initial Methane Notice.

Fortunately, commenter (0831-AXPC) suggests there is a way to avoid this negative scenario, which is both in keeping with the statute and good policy. In its supplemental proposal, the commenter recommends that EPA revise the Initial Methane Notice in the following regard: It should, in the supplemental proposal, propose that new EG OOOOc will only apply to pre-NSPS OOOOa sources, *i.e.*, those sources that did not begin construction or modification before September 18, 2015. This will ensure that new sources subject to NSPS OOOOa are not subject to duplicative methane regulation under that standard as well as the existing-source methane rule in new subpart EG OOOOc. By taking this approach, the commenter states that EPA can avoid both the conflict with the statutory text and design, and the policy problems noted above.

Response I-23-7: See Response I-23-6 of this Chapter.

Comment: Commenter (0810-Petroleum Alliance-OK) states that it is very confusing as to how the Proposed Rule will function collectively. For example, they suggest that it is unclear how the effective dates, requirements, new definitions, *etc.* overlap and/or are triggered pushing an operator into different rule requirements. The commenter encourages EPA to provide clarity as to how each rule (NSPS OOOOa/b/c) will work together, separately or be superseded.

Commenter (0911-NPDC) suggests that EPA should seek to create rules that are easy to understand and implement. The constant amendments, additions, and deletions to the Oil and Natural Gas Sector NSPS have made it difficult for industries and agencies to interpret. The commenter has heard that interpretations between EPA regions and states with primacy vary significantly. The commenter suggests EPA address this by developing regulations and guidance that can be universally understood by agencies and regulated industries.

Commenter (0577-KIOGA) requests clarification regarding affected existing sources constructed on or before November 15, 2021, that will be affected facilities under the EGs of 40 CFR 60, subpart OOOOc, will they continue to also be subject to the NSPS of 40 CFR 60, subparts OOOO or OOOOa, as applicable?

Commenter (0921-USCC) states that the applicability of NSPS OOOO, OOOOa, and OOOOb, and EG OOOOc is unclear. The commenter explains that some preamble language, however, suggests that EPA believes a source can be covered concurrently by requirements for both new and existing sources, and that there will be some sort of yet-to-be-explained process based on the stringency of individual provisions to establish which provisions control. The commenter contends that this view is incorrect as a matter of law and unworkable administratively. In the forthcoming supplemental proposal, the commenter requests that EPA explain how it views the relative applicability of these Subparts.

Commenter (0921-USCC) requests that EPA make clear the following in the supplemental proposal. First, if a source is currently regulated as a “new source” under NSPS OOOO,

OOOOa, or OOOOb, it cannot be regulated as an “existing source” under NSPS OOOOc. Second, EG OOOOc would apply only to those sources not covered by NSPS OOOO or OOOOa on the date of the NSPS OOOOb applicability, which should occur no earlier than the publication date of a supplemental proposal with proposed regulatory text. Third, in the future, sources covered by NSPS OOOOc will transition to Subpart Ob if they undergo a modification or reconstruction. The commenter suggests that this approach is grounded in the statute, eliminates the ambiguity of the current Proposal, prevents unnecessary duplicative regulatory requirements, and also would be workable by the regulated parties and EPA.

Commenter (0727-OK DEQ) states that once the rules are final, there will be four NSPS rules applicable to the oil and gas sector (NSPS OOOO, OOOOa, OOOOb, and OOOOc/State Plan), all of which could potentially be applicable at a single facility, albeit for different components/affected facilities. Because of this, each subpart needs to be clear in the rule text as to where one rule supersedes the other and where applicability of each rule starts and stops for each affected facility. No single component/affected facility should be subject to more than one NSPS or emissions guideline at any given time. The commenter asserts that, without clear rule text, there will be confusion among owners/operators as well as regulators about the applicability of each subpart. Regulatory clarity and certainty pertaining to the applicability of each potential future rule are necessary for effective programs, and the commenter requests EPA pay close attention to this matter when finalizing any future rules.

Response I-23-8: See Response I-23-6 of this Chapter.

Comment: Commenter (0742-ADEC) requests clarification on several aspects of the Proposed Rule. NSPS OOOOa (and presumably, the final NSPS OOOOb proposal will replicate) states: “You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities ... for which you commence construction, modification, or reconstruction after November 15, 2021...”. Also “Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or re-fracturing...” and “Each pneumatic controller affected facility...” and “For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump...” The confusion begins when there are affected facilities (*e.g.*, pneumatic controller) at affected facilities (*e.g.* well-site) including some non-affected facilities that are comprised of many small emissions units (*e.g.* other identical pneumatic controllers) alongside wells that may be affected facilities or not. According to the commenter, tracking the entire affected and non-affected universe of facilities list as well as the applicable requirements can lead directly to compliance risk and concerns. The commenter recommends that EPA propose a simpler and more robust system of compliance tracking that is more readily adaptable to the constant changes due to plant repair and upkeep requirements, especially on the Alaska North Slope, where the repair and replacement maintenance season may be severely limited.

Response I-23-9: In response to comments on the need to provide a rule that is simpler than NSPS OOOOa, the structure of applicability of requirements to affected facilities under the final NSPS OOOOb rule is similar. The definition of affected facilities and the applicability of requirements are affected facility-specific and while the commenter may find compliance tracking challenging, many of the differences are needed to account for specific emissions

mechanisms, technologies, data and feedback from commenters providing support for those differences.

The EPA considered these and other comments when developing the NSPS OOOOb and EG OOOOc regulatory text proposed with the December 2022 Supplemental Proposal.<sup>5</sup> Based on comments on the December 2022 Supplemental Proposal, the EPA made changes and clarifications to the final rules. See section X of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc requirements.

Comment: Commenter (0740-UPA) requests that EPA include a provision in NSPS OOOOb and EG OOOOc regulations such that sites may comply with the most stringent applicable set of requirements between the Federal Implementation Plan (FIP)<sup>6</sup>, NSPS OOOOb, or state regulations adopted under EG OOOOc to meet the EGs, or that a source may voluntarily comply with a more stringent set of regulations in lieu of the FIP, without an obligation to continue to show compliance with the applicable but less stringent set of requirements. The commenter states that such a provision will simplify compliance with recordkeeping, reporting and other regulatory details, and could potentially encourage some operators to voluntarily meet a more stringent standard as a means to harmonize and simplify their overall compliance obligations.

Response I-23-10: While the EPA did not include a provision in NSPS OOOOb and EG OOOOc stating that sites may comply with the most stringent applicable set of requirements between the NSPS OOOOb, state regulations adopted under EG OOOOc and the FIP, the EPA clarified the stringency and applicability of the differing federal rules/requirements under the NSPS and EG in the final rule preamble, including at section IX (Interaction of the Rules and Response to Significant Comments Thereon), as well as in the discussion of individual emission sources.

See also section XIII.C.2 (State flexibilities) of the final rule preamble for a discussion regarding the specific criteria that states need to meet in determining whether a state plan meets the level of stringency required under the final EG.

Comment: Commenter (0577-KIOGA) inquires whether designated existing facilities under 40 CFR 60, Subpart OOOOc will continue to be subject to 40 CFR 60, Subpart KKK. The commenter requests clarification on whether both the NSPS KKK VOC standards will apply and the EG OOOOc presumptively approvable methane standards will apply to these facilities, or if NSPS KKK will no longer apply, and these sources will be regulated by states under EG OOOOc. The commenter further asks whether sources will be subject to regulation under both subparts, and whether EPA has reviewed these subparts such that the sources will not be subject to conflicting requirements and that the requirements are streamlined.

Response I-23-11: The EPA responded to this concern in the preamble for the final rule in addressing applicability.

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<sup>5</sup> For the proposed NSPS OOOOb regulatory text, see Docket ID Number EPA-HQ-OAR-2021-0317-1551; for the proposed EG OOOOc regulatory text, see Docket Number EPA-HQ-OAR-2021-0317-1552.

<sup>6</sup> Federal Implementation Plan for Managing Emissions From Oil and Natural Gas Sources on Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah.

## 23.5 NSPS OOOOb Compliance Timeline

Comment: Commenter (0831-AXPC) suggests that EPA provide a considerably longer time for compliance with the provisions of new NSPS OOOOb after finalization than it otherwise might, or than it has in prior section 111 rulemakings. The commenter believes that a longer time for compliance is specifically appropriate here for three main reasons. First, the subject matter involved in this rulemaking is considerably more complex than it was in most or all prior rulemakings under this section, in terms of, *e.g.*, factors including the scope and types of equipment covered, and the number of sources covered, and the variability from site to site. Second, ongoing supply-chain issues, including but not limited to, the impact of the ongoing pandemic, make it more difficult for companies to prepare for compliance. Third, because the Initial Methane Notice did not include proposed regulatory text for new NSPS OOOOb, companies are even more hindered in their ability to prepare for their eventual compliance options.

Commenter (0831-AXPC) states that they look forward to reviewing the proposed regulatory text for new NSPS OOOOb in the forthcoming supplemental proposal. Based on their review of that proposed regulatory text and the information and analysis that the supplemental proposal will provide, they anticipate that they will be able to provide more detailed comments and suggestions with respect to compliance dates in their comments on the supplemental proposal.

Commenter (0740-Utah Petroleum Association) suggests that EPA provide three years for existing new facilities to come into compliance with NSPS OOOOb.

Response I-23-12: With regards to the compliance timeline for NSPS OOOOb, the EPA has not granted the three-year extension for existing new facilities to come into compliance with NSPS OOOOb. Nonetheless, the EPA has concluded that only sources constructed, modified, or reconstructed after the date of the Supplemental Proposal (December 6, 2022) should be considered new sources for the purposes of NSPS OOOOb. Changing this date to December 6, 2022, from the November 15, 2021, reduces the number of existing new sources that will need to comply with NSPS OOOOb. For details, please see discussion in section IX (Interaction of the Rules and Response to Significant Comments Thereon), subsection A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the final rule preamble. The EPA also provided an alternative compliance timeline in the final rule for process controllers and pumps required to meet a zero-emission standard (*i.e.*, final rule allows up to one year from the publication date of the final rule). See section XI.D.4 (Compliance dates) of the final rule preamble for a discussion on the compliance dates finalized for process controllers (which also applies for pumps). Additionally, the EPA has included several provisions in the NSPS OOOOb final rule that address supply chain issues (*e.g.*, delay of repair provisions for when parts are unavailable for repair).

Comment: Commenters (1085-Small Operator Society LLC, 0847-Mull Drilling Company, Inc.) suggest that EPA should provide a longer implementation period of the rule for small businesses.

Commenter (0598-Countrymark Energy Resources, LLC) recommended providing relief to small entity representatives by including an extended compliance period. For reference, the



commenter notes that EPA did not provide this benefit in the final release of NSPS OOOOa in 2016. At the time of this particular implementation, all companies were required to develop and implement compliance programs within 60 days. The commenter states that EPA has a history of granting small entity representatives an extended compliance period. For example, small business refiners were granted three additional years to implement solutions to reduce the sulfur in their gasoline products (Tier III gasoline standard). In this case, the commenter asserts that EPA recognizing constraints on many small businesses, and granting an additional twelve months for compliance would be meaningful relief.

Response I-23-13: See Response I-23-12 of this Chapter.

## **23.6 General Opposition to the Proposed Rule(s)**

### ***23.6.1 General Opposition***

Comment: Commenters (0321-Hoosier House Furnishing LLC, 0219-Mullet Battery Inc., 0910-AG LA *et al.*, 1300-Public Land Solutions) generally oppose the proposed regulations.

Commenter (0425-Darrah) believes the rule unfairly singles out the oil and gas industry, when the agriculture industry is essentially equal in methane emissions according to EPA. The agriculture industry can voluntarily implement programs and are paid to do so while the oil and gas industry is mandated and subject to burdensome costs. The commenter suggests that the EPA rule is not an equitable station.

Other commenters (0465-Jordan Development, 0572-West Bay Production Company, 0739-Citation, 0790-West Virginia Office of the Attorney General, 0803-OH OG, 0946-MOGA, 1102-TDR Construction, 1155-Bean Ridge Resources) express opposition to the rule(s) based on what they assert will result in impractical, unnecessary and costly burdens associated with requirements under the rule for an industry that is already controlling its emissions:

- Many of the proposed requirements are not practical, such as the monitoring of wells that are plugged, as the supervision and authority for well plugging is vested with the state. (0572-West Bay Production Company)
- The Proposed Rule's emission controls, monitoring, and recordkeeping requirements are burdensome and will stifle the continued development of oil and natural gas resources in Ohio. Such a result will have a substantial negative impact on homeowners, farmers, and small businesses, particularly in underserved rural communities in Ohio. The commenter suggests that EPA should revise the Proposed Rule by providing more regulatory flexibility and less stringent emissions control requirements where practical realities dictate as much. (0803-OH O&G)
- The cost of the implementation, especially the monitoring and compliance, will devastate small businesses. The commenter is also uncomfortable with the liability insurance and risk of having untrained personnel on their oil lease. There is also not a clear amount of emissions per bbl of oil [barrel of crude oil] to determine if you have to implement the monitoring. (1102-TDR Construction, Inc.)

- The potential reporting burden from the inclusion of existing facilities could be very large. The commenter requests the reporting requirements for any existing facilities be removed or minimized. (0739-Citation)
- The proposed regulations appear to unfairly penalize companies who have been reducing emissions since implementation of Subpart OOOO. The commenter questions how the purchase and financing of existing wells is different than drilling new wells. The commenter asks for clarity on how costs will change when considering new regulations. Lastly, the commenter questions how EPA's emission reduction goals can be met when the proposed regulations are changed every 2 to 4 years. It doesn't appear that production decline is even considered. The commenter urges EPA to reconsider and instead to work with industry to develop a plan that allows small companies to continue to profit and move forward. (1155-Bean Ridge Resources)

Commenter (0946-MOGA) questions EPA's use of 2019 emission data to justify the current proposed regulations. Based on historic rulemaking efforts, if the full implementation of NSPS OOOOa did not begin until roughly 2018 (considering the 2-year & 90-day court stay), the commenter inquires how can EPA determine the effectiveness of the NSPS OOOOa regulations and justify the new proposed regulations? The commenter states that, as shown in the emissions reduction table in Comment number "2" of their comment letter (regarding Pragmatic and Economic Viability Concerns), Michigan producers have been successful in reducing emissions through NSPS OOOO and OOOOa regulations. [Emission reduction table shows reductions show a range of 40 to 90 percent reduction in methane emissions from 2011 to 2020 for 3 companies, with an average reduction in methane emissions of around 65 percent). The commenter notes that the three small businesses included in the emission reduction table have invested significant capital to achieve emission reductions without EPA allowing enough time to recover costs. Based on this data, the commenter believes that EPA should allow more time to evaluate current regulations applied to new sources and future modifications of previously non-regulated sources before amending regulations resulting in another substantial economic burden on small business producers.

Similarly, commenter (0465-Jordan Development) argues that existing regulations for new wells including NSPS OOOO and NSPS OOOOa combined with natural production formation depletion will facilitate EPA's emission reduction goals. The commenter evaluated their 40 CFR Part 98, Subpart W annual reported Carbon Dioxide (CO<sub>2</sub>), Methane (CH<sub>4</sub>) and Nitric Oxide (NO<sub>x</sub>) emission over the 9-year reporting period from 2011 through 2020. From the data, Jordan observed an average annual methane reduction of 4.8% and a total methane emission reduction of 43.20% to date. EPA indicated that they used 2019 emission data to justify the current proposed regulations. If the full implementation of NSPS OOOOa did not begin until 2018 (considering the 2-year & 90-day stay), the commenter asks how can EPA determine the effectiveness of the current regulations and justify the new proposed regulations? The commenter states that their efforts to implement NSPS OOOO and OOOOa regulations has resulted in significant capital investment for their small business to reduce emissions without EPA allowing enough time to recover costs. The commenter believes that EPA should allow more time to evaluate current regulations applied to new sources and future modifications of previously non-regulated sources before amending regulations resulting in another substantial economic burden on small business producers.

Response I-23-14: The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions as outlined in the preamble to the final rule accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

In response to comments that state that industry has already been effective at reducing emissions under the NSPSs OOOO and OOOOa, the EPA agrees. However, greater emissions reductions of VOC and methane emissions are needed. As discussed in the final rule preamble, these final actions stem from the EPA's authority and obligation under CAA section 111 to directly regulate categories of new stationary sources that cause or contribute to endangerment from air pollution and to promulgate EG for states to follow in regulating existing sources (designated facilities) in the source category. See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

As discussed in section VIII.B (How does EPA evaluate control costs in this final action?) of the final rule, the final standards will impose some new costs on industry (including small businesses). Many of the standards, however, reflect control mechanisms and measures that many companies and sources around the country are already implementing – again, without deleterious effect on industry as a whole – which shows not only that such controls are "adequately demonstrated" but also underscores their reasonableness from a cost perspective. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in the November 2021 Proposal and the December 2022 Supplemental Proposal, as well as in section XI of this preamble and associated TSDs. See also Volume II, Chapter 4 (Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations), section 4.3.4 (Small Business/Cost Concerns) comments and responses on small business/cost concerns related to fugitive emissions requirements.

Also, the revised Initial Regulatory Flexibility Analysis (IRFA) and Final Regulatory Flexibility Analysis (FRFA) provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses that will also, in many cases, reduce regulatory burden for many large businesses. In addition to providing several compliance alternatives for affected facilities under NSPS OOOOb and designated facilities under EG OOOOc, the EPA has also considered issues such as lingering supply chain issues and increased demand for equipment and services when establishing compliance, and repair and delay of repair provisions included in the final NSPS OOOOb and EG OOOOc rules to account for parts not being available.

With respect to EPA using 2019 emissions data, when the EPA developed the November 2021 Proposal, the most up to date emissions data was for the Year 2019, and the EPA has maintained this baseline in subsequent analyses in support of these actions for consistency. Note that the present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this

rulemaking is in 2019 dollars; and the Regulatory Impacts Analysis (RIA) estimated the cost, emissions, and benefit impacts for the 2024 to 2038 period.

### ***23.6.2 Interaction with State Regulations***

Comment: Commenter (0957-WY CLG) asks EPA to approach this area with caution and first determine what if any role should EPA play. This proposed rulemaking greatly expands the regulatory reach over the oil and gas industry by proposing more stringent VOC and GHG emission standards and monitoring requirements for new sources, subjecting more equipment and processes to the standards, and proposing EGs for existing sources. The commenter provides that western states have developed rules that link environmental protection, land use and production. The EPA top-down rules will only interfere with the current system with the goal of reducing emissions at great cost to the industry and the states. The over regulation of the oil and gas industry will only lead to continued production declines and increased reliance on imports to meet the nation's energy demands.

Response I-23-15: In response to the comment that the November 2021 Proposal greatly expands regulation, and that over regulation of the oil and gas industry will only lead to continued production declines and increased reliance on imports to meet the nation's energy demands, we disagree. There are a lot of variables influencing production and demand that extend beyond regulations impacting the oil and gas industry. See Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.6 (Energy Impacts), Responses I-20-25 and I-20-26 for EPA's response to comments on the expected impacts of the final NSPS OOOOb and EG OOOOc regulations on domestic oil and natural gas production.

See also sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

### ***23.6.3 Domestic/Global Oil and Natural Gas Resource Demand Considerations***

Comment: Commenter (0921-USCC) suggests that the Proposed should consider the importance of maintaining the nation's energy security and continuing the development of our natural resources to maintain comparatively low energy prices. The commenter also suggests that EPA consider and support the availability and growth of good-paying jobs in the oil and gas sector.

Commenter (0921-USCC) states that while crafting a methane regulation that will be durable and cost-effective, it is critical that EPA maintain and not undercut the energy security that the shale revolution has provided for the nation. In 2019, the U.S. enjoyed its best energy security since 1970.<sup>7</sup> In addition, the U.S. became a net energy exporter in 2019 for the first time since 1952.<sup>8</sup> After achieving a record high risk score in 2011 of 100.[9], the total U.S. energy security risk

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<sup>7</sup> See Global Energy Institute ("GEI"), U.S. Chamber of Commerce, "Index of U.S. Energy Security Risk – 2020 Edition" Table 1, [https://www.globalenergyinstitute.org/sites/default/files/2020-10/024036%20Global%20Energy%20Institute%20US%20Index\\_Web.pdf](https://www.globalenergyinstitute.org/sites/default/files/2020-10/024036%20Global%20Energy%20Institute%20US%20Index_Web.pdf).

<sup>8</sup> U.S. Energy Information Administration ("EIA"), "U.S. Energy Facts Explained" <https://www.eia.gov/energyexplained/us-energy-facts/imports-and-exports.php>.

score fell in seven of eight years, achieving a record low of 70.1 in 2019 (a 5.5 percent decrease from 2018.).<sup>9</sup> This record achievement in reduced energy security risk is a direct result of the increased energy production and usage made possible by advanced hydraulic fracturing technology.<sup>10</sup>

Importantly, commenter (0921-USCC) states that the increased energy security in the U.S. due to production of oil and gas from shale occurred while the U.S. maintains one of the lowest methane intensity measures in the world associated with its energy production.<sup>11</sup> In addition, largely as a result of natural gas fueling an ever increasing portion of electricity generation, overall CO<sub>2</sub> emissions from fossil fuel combustion decreased by 896.8 million metric tons of CO<sub>2</sub> equivalent (MMT CO<sub>2</sub>e) from 2005 levels to 2019, a decrease of approximately 15.6 percent.<sup>12</sup> From 2018 to 2019, emissions decreased by an additional 134.7 MMT CO<sub>2</sub>e (2.7 percent).<sup>13</sup>

Commenter (0921-USCC) states that the decreases in emissions and reduced methane intensity from energy production were achieved while natural gas production rose to a record level in 2019, climbing 10.6 percent to 40.7 trillion cubic feet (tcf).<sup>14</sup> The U.S. led the world in natural gas production in 2019. Increases in Texas (1.3 tcf) and Pennsylvania (0.8 tcf) accounted for most of the increase.<sup>15</sup> Colorado, Louisiana, New Mexico, North Dakota, Ohio, Oklahoma, and West Virginia also contributed increased output. This data underscores the abundance of natural gas throughout the country and its comparative value in enabling reductions in both energy security risk and emissions.

Moreover, when it comes to prices, Commenter (0921-USCC) believes America's households and industrial consumers benefit greatly from our energy advantage. The U.S. pays two to six times less than counterparts in Europe and other industrialized nations.<sup>16</sup> With natural gas stocks at historically low levels, prices breaking records, and several weeks of potential winter demand spikes still to come, many European leaders are concerned that a firm response to Russian aggression could lead to energy supply disruptions. It's a stark reminder that energy security is national security, and as Europe looks to diversify its supplies, the United States is poised to help.

Commenter (0921-USCC) states that since 2005, annual consumption of natural gas in the United States has increased by nearly 41 percent or 9 tcf. Electric power (up 60 percent) and

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<sup>9</sup> GEI "Index of U.S. Energy Security Risk – 2020 Edition," p.4.

<sup>10</sup> Id.

<sup>11</sup> See Daniel Byers, "The Best Solution to Pain at the Pump is Here in America," GEI, U.S. Chamber of Commerce (Aug. 17, 2021), <https://www.globalenergyinstitute.org/best-solution-pain-pump-here-america>.

<sup>12</sup> U.S. EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019" EPA 430-R-21-005, pp. ES-11 and 2-13, available at <https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-maintext.pdf?VersionId=yu89kg1O2qP754CdR8Qmyn4RRWc5iodZ>.

<sup>13</sup> Id.

<sup>14</sup> See GEI "Index of U.S. Energy Security Risk – 2020 Edition," supra note 3.

<sup>15</sup> Id.

<sup>16</sup> See Daniel Byers, "U.S. Natural Gas Exports Deliver More Than Just Energy," GEI, U.S. Chamber of Commerce (Jan. 27, 2022), <https://www.globalenergyinstitute.org/us-natural-gas-exports-deliver-more-just-energy>.

industrial sector use (up 28 percent) comprise nearly 90 percent of the increase.<sup>17</sup> Thus, natural gas has displaced other power generation sources to become the primary fuel for electric power generation over the past 10 years.<sup>18</sup> This has led to drastic reductions in national carbon emissions since 2005.<sup>19</sup> Natural gas also now provides almost a third of the energy to the U.S. industrial sector.<sup>20</sup> It is used for on-site electricity generation (fueling boilers and turbines); process heat to melt glass, process food, preheat metals, and dry various products; and combined heat and power (CHP) systems.<sup>21</sup> Natural gas is also used as a material input itself—as a feedstock as opposed to being combusted—to make products such as fertilizers, chemicals, and plastics. All economic sectors consume natural gas.<sup>22</sup> This is in part due to the low cost of production of natural gas driven by the shale revolution.<sup>23</sup>

Commenter (0921-USCC) believes that, in the development of its supplemental proposal to regulate new, modified, reconstructed, and existing sources, EPA will be able to meet its GHG reduction goals and incorporate critical aspects of energy security into its deliberations. As demonstrated by the reductions in overall carbon emissions and methane intensity from energy production over the last decade, EPA can drive down GHG emissions without undermining the continued economic security that oil and gas production provides. As EPA designs its regulatory framework, it should be careful to avoid creating a structure that would disincentivize domestic energy production. With market and technological innovations in the oil and gas sector, combined with smart regulations and protocols, EPA can build a certain, predictable, and environmentally effective compliance regime.

Response I-23-16: See Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.6 (Energy Impacts), Responses I-20-25 and I-20-26, for EPA’s response to comments on the expected impacts of the final NSPS OOOOb and EG OOOOc regulations on domestic oil and natural gas production.

Comment: Commenter (0595-Consumer Energy Alliance) urges EPA to balance the economic welfare of the nation’s energy consumers as well as current progress toward emission reductions, as it contemplates actions related to greenhouse gases and overall environmental stewardship. America has demonstrated we can accomplish both of these critical objectives at the same time.

Response I-23-17: See Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.6 (Energy Impacts), Responses I-20-25 and I-20-26 for EPA’s response to comments on the

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<sup>17</sup> Center for Climate and Energy Solutions (“C2ES”) <https://www.c2es.org/content/natural-gas/> (last visited Jan. 31, 2022).

<sup>18</sup> Id.; see also U.S. Energy Information Administration (“EIA”), <https://www.eia.gov/naturalgas/> (last visited Jan. 31, 2022).

<sup>19</sup> See C2ES, *supra* note 13; U.S. EPA, *supra*, note 8.

<sup>20</sup> Id.

<sup>21</sup> See C2ES, *supra* note 13; see also U.S. EIA, “Natural Gas Consumption by End Use” available at [https://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_nus\\_m.htm](https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm) (last visited Jan. 31, 2022).

<sup>22</sup> Id.

<sup>23</sup> See Daniel Byers, “More Gold Medals for America’s Energy Producers,” GEI, U.S. Chamber of Commerce (Jul. 28, 2021), <https://www.globalenergyinstitute.org/more-gold-medals-americas-energy-producers>.

expected impacts of the final NSPS OOOOb and EG OOOOc regulations on domestic oil and natural gas production.

Comment: Commenter (0951-Ridgeling Energy LLC) states that Europe is in critical need of our exported frozen gas (liquefied natural gas (LNG)) and that even our annual production of natural gas is not enough to support their needs. Due to Russia using natural gas to split European support for NATO, the U.S. cannot give up 10 percent to 12 percent of their natural gas.

Commenter (0334-Gas and Oil Association of WV, Inc.) requests that EPA pause and recognize the critical role energy plays in the lives of all Americans. The stark reality is natural gas produced here must remain a key component of the U.S. energy portfolio. It's use as a heating fuel, in manufacturing processes, and for low-emission power generation should be embraced and encouraged by the Biden Administration. Natural gas produced in West Virginia is done so under the most stringent regulatory and environmental standards in the nation; and U.S. standards far surpass those of other nations.

Commenter (0334-Gas and Oil Association of WV, Inc.) states that natural gas is a global commodity and in great demand throughout the world. Domestically, we have the capability to be energy dominant. Shifting this energy production to distant countries that fail to adhere to the standards followed by American companies will not provide the positive global emission reductions that will lead to better air quality nor achieves global climate goals.

Commenter (0861-Discovery Operating, Inc.) has been in upstream oil and gas production for 60 years and has learned that any rule such as the proposed EPA Methane Rule, that would handicap production from thousands of low producing oil and gas wells would greatly damage America's best strategic petroleum reserve. The proposed rule could cause many of our stripper wells to be plugged and abandoned. The commenter contends that any rule that jeopardizes the oil and gas industry and long-lasting oil and gas reserves reduces the security of the nation.

Commenter (0599-MSC) suggests that any final rules should have a reasonable and cost-effective pathway to compliance. The commenter states that American natural gas and liquids are critical to both missions: providing affordable, clean energy to heat and power American homes, schools, businesses, and other facilities while fueling American manufacturers, including pharmaceuticals, as evidenced by the role natural gas liquids are playing in the health care arena, from medical equipment to vaccine development and deployment.

Response I-23-18: In response to comments that state that the rule would handicap production from thousands of low-producing oil and gas wells and would cause many of their stripper wells to be plugged and abandoned, the EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the final rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry.

See also Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.6 (Energy Impacts), Responses I-20-25 and I-20-26, for EPA's responses to comments on the expected

impacts of the final NSPS OOOOb and EG OOOOc regulations on domestic oil and natural gas production.

Comment: Commenter (0800-Utah Public Lands Policy Coordinating Office and Utah Division of Air Quality) supports natural gas energy production and related development, as “Utah is an ‘all-of-the-above’ energy state” meaning “there is room for all types of energy production and distribution”<sup>24</sup> both conventional and renewable. To date, this all-of-the-above energy policy has served Utahns well,<sup>25</sup> and the state supports all reasonable forms of energy development and generation available within its borders.

Commenter (0800-Utah Public Lands Policy Coordinating Office and Utah Division of Air Quality) states that as evidence of the success of this policy, Utah currently generates more electricity than it consumes, and the state is a net supplier of power to other states.<sup>26</sup> As of 2020, coal fueled 61% of Utah's total electricity net generation, down from 75% five years earlier, and natural gas accounted for 25%. Almost all of the rest of Utah's in-state electricity generation came from renewable energy sources, primarily solar power.<sup>27</sup> This trend is expected to continue, and Utah's Strategic Energy Plan anticipates natural gas-fired generation will replace coal and will back up intermittent renewables like wind and solar power.<sup>28</sup> In fact, no new coal-fired generators have been built in the state since 1993, but about 60 natural gas-fired units have been put into service since then.<sup>29</sup> As part of its overarching policy, the State is committed to continuing to diversify its energy portfolio and has adopted a voluntary goal of obtaining 20 percent of its adjusted retail electric sales from renewable energy resources by 2025.<sup>30</sup> In fact, about 97% of Utah's electric generating capacity added since 2015 is powered by solar energy.<sup>31</sup>

However, the commenter (0800-Utah Public Lands Policy Coordinating Office and Utah Division of Air Quality) states that due to the intermittent characteristics of some forms of renewable energy (wind, solar, &c.), there is still a need for electricity generation that can be available to the electricity grid 24/7, regardless of weather conditions. This need for

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<sup>24</sup> Thom Carter, Why expanding renewable energy means more mining, not less, Deseret News, available at: <https://www.deseret.com/2021/4/7/22360352/keep-it-in-the-ground-energy-policy-renewable-traditional-wind-solar-batteries-critical-minerals> (2021).

<sup>25</sup> Id.

<sup>26</sup> EIA, Utah – State Energy Profile Analysis, U.S. Energy Information Administration, available at: <https://www.eia.gov/state/analysis.php?sid=UT> (2021); citing U.S. EIA, Utah Electricity Profile 2019, Table 10, Supply and disposition of electricity, 1990 through 2019.

<sup>27</sup> Id.; citing U.S. EIA, Electricity Data Browser, Net generation for all sectors (thousand megawatthours), Utah, 2001-20.

<sup>28</sup> Id.; citing Utah Governor's Office, Energy Initiatives and Imperatives: Utah's 10-Year Strategic Energy Plan 2.0, updated February 2014, p. 25-26.

<sup>29</sup> Id. citing U.S. EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generators as of December 2020, Plant State: Utah, Technology: Natural Gas.

<sup>30</sup> Id.; citing NC Clean Energy Technology Center, DSIRE, Utah, Renewable Portfolio Goal, updated July 3, 2018.

<sup>31</sup> Id. citing U.S. EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860), Inventory of Operating Generators as of December 2020, Plant State: Utah, Technology: Select All.



“dispatchable” energy - meaning energy that can be ramped up or down quickly to make up for intermittency caused by other renewable energy resources - is highlighted by current events.

Commenter (0800-Utah Public Lands Policy Coordinating Office and Utah Division of Air Quality) states that with recent actions taken by the Biden Administration<sup>32</sup> (and subsequent litigation)<sup>33</sup> there is a push by the current President to “tackle” climate change by shifting away from traditional energy sources such as oil and gas. As the United States tackles climate change by transitioning to low-carbon energy resources, it is imperative that baseload and dispatchable energy sources (such as natural-gas) remain viable and online. If fossil-fueled energy systems are retired at a pace that is greater than renewable projects are brought online, then our nation almost certainly will experience a host of adverse effects due to insufficient energy – rolling blackouts or system failures causing death by exposure to extreme temperatures, and exorbitant energy bills which unfairly burden individuals, businesses, and local governments.

With this expectation in mind, the commenter (0800-Utah Public Lands Policy Coordinating Office and Utah Division of Air Quality) believes it is critical to remember that if we reduce our reliance on fossil fuel energy systems at a pace that is greater than renewable projects are developed, and without the necessary baseload and dispatchable energy sources (such as natural gas) remaining viable and online, then we must expect these extreme weather events to wreak even more havoc on the environment and human life. Energy, regardless of its source, plays a significant role in ameliorating the deleterious effects of severe meteorological phenomena on human life. Unfortunately, the possibility of energy shortfalls is conceivable as our Nation and some of its states attempt to aggressively cut fossil fuel use by, among other things, pulling permits for crude oil pipelines,<sup>34</sup> denying access to state lands for interstate natural gas pipelines,<sup>35</sup> and pausing oil and gas lease sales on public lands and in offshore waters.<sup>36</sup> In light of these potential energy shortfalls, Utah remains committed to its “all-of- the-above” energy approach, and asserts that it remains imperative that any future regulatory changes (such as the current Proposal) not inhibit fossil fuel development to a point where it becomes unviable. The State has adopted specific policies in furtherance thereof.

Response I-23-19: The EPA acknowledges and commends Utah in their support for natural gas energy production and related development, both conventional and renewable. The EPA also agrees that while addressing climate change by transitioning to low-carbon energy resources, it is important that baseload and dispatchable energy sources (such as natural-gas) remain viable and online. See Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.6 (Energy Impacts), Responses I-20-25 and I-20-26 for EPA’s responses to comments on the expected

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<sup>32</sup> E.O. 14008 of Jan 27, 2021.

<sup>33</sup> *Louisiana, et al. v. Biden*, CIV. NO. 2:21-CV-00778-TAD-KK.

<sup>34</sup> Joseph R. Biden, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis Executive Order 13990 at Section 6. *Federal Register* 86(14): 7041, 7037-7043 Available at <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/>.

<sup>35</sup> Brent Kendall and Timothy Puko, “Supreme Court Rules New Jersey Can’t Block Natural-Gas Pipeline (Wall Street Journal, June 30, 2021). Available at [https://www.wsj.com/articles/supreme-court-rules-new-jersey-cant-block-natural-gas-pipeline-11624977295?mod=trending\\_now\\_news\\_pos4](https://www.wsj.com/articles/supreme-court-rules-new-jersey-cant-block-natural-gas-pipeline-11624977295?mod=trending_now_news_pos4).

<sup>36</sup> Joseph R. Biden, Tackling the Climate Crisis at Home and Abroad Executive Order 14008 at Section 208, *Federal Register* 86(19): 7619-7633 February 1, 2021.

impacts of the final NSPS OOOOb and EG OOOOc regulations on domestic oil and natural gas production.

## 23.7 General Support for the Proposed Rule(s)

Comment: Several commenters (*e.g.*, 0201-Lone Star Chapter of the Sierra Club, 0317-National Affairs and Legislation Committee and The Garden Club of America, 0339-Cheyenne Area Landowner's Coalition, 0385-Silent Spring Institute, 0387-Climate Writers, 0391-Keweenaw Bay Indian Community (KBIC), 0398-US House of Representatives, 0401-Mercy Investment Services, 0405-Prostate Citizen, 0406-Boone and Crockett Club, 0427-Private Citizen, 0434-Pax World Funds, 0435-Wespath Benefits and Investments, 0437-State of NY Comptroller, 0443-SGI, 0444-Damascus Citizens for Sustainability, 0455-Radio Drama Network, 0460-Trinity Health, 0538-Change Finance, 0560-Legal & General Investment Management America, 0569-Wellington Management Company, 0579-Chevron, 0581-NACAA, 0583-Harvard Management Company, Inc, 0584-EIG Global Energy Partners, 0586-Navajo Nation Environmental Protection Agency, 0587-US Well Services Inc, 0589-NEI Investments, 0600-PIMCO, 0592-Citizens United for Responsible Energy Development, 0601-CT DEEP, 0605-Muscogee Creek Nation, 0610-Occidental, 0715-Dayenu Circle of Jewish Silicon Valley, 0721-Moms Clean Air Force, 0723-Ceres, 0725-National Grid USA, 0733-CVNM, 0734-American Thoracic Society, 0735-Chesapeake Bay Foundation, 0737-Clarke Valve, 0738-Exxon Mobil Corporation, 0752-AF&PA, 0753-IGSD, 0754-National Religious Partnership for the Environment, 0757-Private Equity Stakeholder Project, 0761-Exelon Corporation, 0769-CARB, 0770-Northern Plains Resource Council, 0781-NTAA, 0785-John Crane, 0786-Enerplus Resources Corporation, 0795-Allergy & Asthma Network, 0807-BP, 0809-Earthjustice, 0821-Xcel Energy, 0828-Union of Concerned Scientists, 0830-Devon Energy, 0832-NMED, 0833-UMUT EPD, 0838-TRIDO, 0839-Continental Resources, 0840-Navajo Nation, Counselor Chapter House, 0917-Our Children's Trust, 0918-CO CCA, 0919-TEP Rocky Mountain LLC, 0920-We Act for Environmental Justice, 0921-USCC, 0926-Austin Energy, 0927-Interfaith Center on Corporate Responsibility, 0931-Essential Information Inc, 0943-Sault Ste. Marie Tribe of Chippewa, 1160-Uinter Methodist Women of the Desert Southwest Conference, 1271-Lee Memorial AME Church, 1301-Northern Arapaho Tribe Business Council, 1302-Wyoming Outdoor Council, 1322-Lone Star Chapter of the Sierra Club, 1330-Catskill MK, 1337-Boston Catholic Climate Movement, 1350-EOS at Federated Hermes, 1377-Lander Climate Action Network, 1383-Interfaith Power & Light New Mexico, 1384-Louisiana Environmental Action Network, 1387-350 Bay Area Action, 1388-Private Citizen, 1389-VERIS Wealth Partners, 1423-US Congress, 1434-US Senate) generally support efforts from EPA and other federal agencies to reduce emissions from the entire oil and gas industry. This includes extraction and production, processing, transmission, and distribution. Most commenters are asking for a rapid promulgation of the final rule in order to achieve the estimated emission reductions so that citizens can experience the health and environmental benefits. Examples of some of the reasons that commenters provided as support include the following:

- The climate crisis requires urgent action by the federal government in order to reduce air pollution and the associated human health consequences.
- The standards will be especially helpful in protecting communities of color and other vulnerable communities (*e.g.*, children, the elderly, immunocompromised, persons with

asthma/cardiovascular issues, lower socio-economic communities) which are hit hard by climate change and air pollution.

- The application of the proposed standards to more new and existing sources than in the past.
- Affordable, domestically produced natural gas has been one of the primary driving forces behind significant reductions in carbon emissions achieved over the past decade, most notably from the power generation sector.
- Targeting the wasted methane emissions from the oil and gas sector is a largely cost-effective and low-hanging solution among a much longer list of policy actions that are needed to mitigate the most severe impacts of climate change later this century.<sup>37</sup>
- Direct federal regulation of methane emissions from the oil and gas industry are more effective than most state or voluntary efforts.
- The cost of compliance with the proposed standards would be relatively low.<sup>38</sup>
- The proposed rules would encourage the use of innovative methane detection technologies and other cutting-edge solutions, many of which are being developed and utilized by small businesses providing robust jobs in the United States.
- The proposed rule(s), once implemented and enforced, will result in significant and meaningful reductions of air pollutants that negatively impact public health and the environment, including a significant reduction in ozone precursor pollutants which will result in lower ozone concentrations, a significant reduction of methane, a potent GHG that contributes to climate change, and a significant reduction in both toxic and hazardous air pollutants, including carcinogens such as benzene.
- The proposed standards will establish a baseline set of requirements that apply nationwide and will help to align the varying approaches by states to address emissions from the O&G sector, especially where emissions from one state may impact affected areas in another state.
- Methane reduction in oil and gas production is an immediate and cost-effective opportunity to reduce the rate of climate warming.
- It is essential these sources of methane emissions are addressed adequately to meet the commitments of the Global Methane Challenge and President Biden's nationally determined contribution (NDC) to at least halve economy wide GHGs below 2005 levels by the end of the decade.
- Strong regulations are needed to level the playing field and accelerate industry-wide methane reduction and the energy transition.
- Strong methane regulation and regulatory certainty is essential to the success of companies in both the oil and gas industries, as well as companies that may be affected by climate change in other ways.
- Ambitious methane regulations can assist investors to better execute a more effective transition risk-mitigation strategy, as a predictable regulatory landscape is likely to lead to increasingly dependable capex guidance and improved data transparency.
- Robust regulation would quicken and streamline emissions reduction, providing assurance of the lower-emissions profile of US-produced natural gas.

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<sup>37</sup> International Energy Agency: Curtailing Methane Emissions from Fossil Fuel Operations. Oct. 2021.

<sup>38</sup> Investor Guidance on EPA Proposed Standards for Oil and Natural Gas Methane Emissions, EDF, December 2, 2021.

- An effective regulation, which broadly limits emissions across hard-to-abate sectors such as oil and natural gas, is essential to advance mitigation and meet climate goals.
- Reduction of VOCs nationally will help reduce local emissions of ozone and ozone precursor transport from states with significant oil and gas production.
- The Texas Commission of Environmental Quality (TCEQ), the Texas Railroad Commission (which governs fossil-fuel extraction, NOT railroads), and the Texas State legislative and executive branches is not doing enough to make a difference in the battle against climate change.

Response I-23-20: Comments are supportive comments for EPA’s proposals; as such, no response is required.

Comment: Commenter (1340-Citizens United for Responsible Energy Development) agrees that the proposed methane reduction rules will minimize methane into the atmosphere and reduce its explosive impact as a GHG. The commenter has never fought energy development in the Upper Green as they recognize the substantial positive economic effect that natural gas production has in the Basin; the commenter just insists that it be done responsibly. The new rules can be a step in this direction. Development must include a clean and healthy environment and a quality of life where humans don’t contend with “ozone days” -- those with compromised lungs aren’t hospitalized, and schools don’t need to prohibit children from going outside for recess in January, or February, or March. Commenter urges EPA to move quickly and decisively in adopting standards that will accomplish this.

Response I-23-21: Comments are supportive comments for EPA’s proposals; as such, no response is required.

Comment: Commenter (0761-Exelon Corporation) strongly supports EPA’s Proposal and offers comments focused on the following points:

- EPA is legally obligated to regulate methane emissions from the crude oil and natural gas category under the Clean Air Act (CAA).
- In the EGs for existing sources, EPA must identify the “degree of emission limitation achievable” through application of the “best system of emission reduction.”
- The EGs should include presumptive standards of performance for all designated facilities that, if adopted in a state plan, would make the plan presumptively approvable by EPA.
- EPA has authority to approve a state plan that requires measures that are more stringent than the EGs.
- The social cost of methane should guide Agency decision-making.
- A consideration of costs and benefits of an Agency action should include consideration of all quantifiable and unquantifiable, direct and indirect, costs and benefits.
- A final rule should include meaningful measures to protect disadvantaged and overburdened communities from the effects of air pollution.
- All contents of regulatory Docket ID No. EPA-HQ-OAR-2021-0295 should be included in the record for Docket ID No. EPA-HQ-OAR-2021-0317.

Response I-23-22: For comments that are supportive comments for EPA's proposals; no response is required. The EPA, in the development of the final NSPS OOOOb standards and EG OOOOc presumptive standards considered these and other comments on the November 2021 Proposal and December 2022 Supplemental Proposal in the development of the NSPS OOOOb and EG OOOOc rule requirements.

With regards to the request that the contents of non-rulemaking Docket ID No. EPA-HQ-OAR-2021-0295 be included in the rulemaking Docket ID No. EPA-HQ-OAR-2021-0317, the EPA has not granted that request. The EPA opened the non-rulemaking docket (Docket ID No. EPA-HQ-OAR-2021-0295) for public input on the Agency's efforts to reduce emissions of methane and other air pollutants from new and existing sources in the oil and natural gas sector in order to further the Administration's policies as described in Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." The goal of this non-rulemaking docket and other public engagement efforts was to gather perspectives from a broad group of stakeholders for the oil and natural gas sector, including individuals and communities that experience disproportionate adverse health and environmental impacts as a result of oil and natural gas operations.

Comment: Commenter (0752-AF&PA) generally supports the proposed rules because they aim to reduce emissions from natural gas pipelines, which the commenter asserts will reduce their costs and may increase safety from detection of leaks, the commenter is not taking a position on the legal rationales or CAA interpretations underlying the Proposed Action. In general, commenters are supportive of the need for common sense regulations that do not impose unnecessary administrative burdens and cost on regulated parties. As EPA develops the rule, the commenter recommends the agency provide compliance flexibility and consider cost effectiveness. As noted above, due to methane leaks from natural gas pipelines the commenter is paying for natural gas that does not reach their facilities. Moreover, following natural gas pipeline incidents, the commenter has incurred very significant costs in terms of curtailment, lost production, and increased gas and power costs. The pulp and paper industry and certain PGC members alone are estimated to have paid at least \$50 million for fuel and lost gas in 2018.

Response I-23-23: This comment is a supportive comment for EPA's proposals; as such, no response is required. Please also see section VIII.B (How does the EPA evaluate control costs in this final action?) of the final rule preamble for a discussion on how the EPA evaluates control costs, and section X of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc requirements. Specifically, see section X.C (Super Emitter Program) of the final rule preamble on EPA's Super Emitter Program to ensure that the final rulemaking comprehensively addresses the widespread problem of abnormally large emissions events known as super-emitters.

Comment: Commenter (0339-Cheyenne Area Landowner's Coalition) is supportive of the new methane standards from the Proposal. The commenter has learned from multiple state examples, that most oil and gas operators respond to that which is required by rule or law.

Commenter (0339-Cheyenne Area Landowner's Coalition) believes that the new methane requirements for the oil and gas industry have the potential to significantly improve air quality in

Laramie County, as well as the rest of the State. DEQ's Air Quality Division has demonstrated a propensity to do only that which will keep the agency in compliance with EPA requirements. Here are three examples:

1. Air quality in the Upper Green River Basin has experienced ozone pollution severe enough that the area has been determined to be a nonattainment area. As such DEQ strengthened the air quality standards in this area. DEQ missed the opportunity to improve air quality in Wyoming when it determined it would not implement these stricter standards statewide, despite local urging that it do so. What is good enough for EPA is viewed as good enough for Wyoming.
2. The Air Quality Division of DEQ is required to demonstrate that it is monitoring air quality in Wyoming, including in Laramie County. A couple of years ago, the Air Quality Division placed a mobile air monitoring station in eastern Laramie County. The problem was in the location of this mobile unit. Instead of placing the unit in an area where there was significant oil and gas development, DEQ placed the unit at a very rural fire station miles and miles from the nearest well pad. The Cheyenne Area Landowner's Coalition recommended that the unit be relocated to a place where meaningful results could be anticipated. DEQ ignored our concerns, and the results were meaningless as expected. DEQ then decided to move the mobile unit out of Laramie County and relocate it in distant Fremont County. Another missed opportunity to demonstrate the impact of oil and gas operations on the quality of the air local residents breathe.
3. In November 2020, the Cheyenne Area Landowner's Coalition in partnership with the Powder River Basin Resource Council, hired a professional to photograph methane and other VOC emissions from a number of existing well sites in Laramie County, using a FLIR camera. The results were reported to DEQ's Air Quality Division, with a request that it follow up with the appropriate oil and gas operators. Part of the response from DEQ was that since these emissions were not visible with the naked eye, there was no violation of EPA (Section 22) standards. Hence there was no corrective action needed. Methane of course is not visible to the naked eye.

Commenter (0339-Cheyenne Area Landowner's Coalition) suggests the creation and implementation of new methane standards will result in Wyoming' DEQ being required to do a better job of monitoring and improving air quality in Wyoming. And these improved standards will contribute to the overall objective of slowing the pace of global warming. Thanks for the opportunity to comment.

Response I-23-24: This comment is a supportive comment for EPA's proposals; as such, no response is required.

Comment: Several industry commenters generally support the proposed actions (0808-API, 0817-GPA, 0820-Pioneer, others) with comments that provide corrections, improvements, concerns. These comments are provided in the relevant Chapters of this document.

Commenter (0839-Continental Resources) applauds EPA's effort to move forward to reduce emissions of GHG and other harmful air pollutants from the Crude Oil and Natural Gas source category, although they do not agree with all the methods or presumptions provided by

the proposal. The commenter issues this broad endorsement to the industry groups it supports because all the comments being submitted show consistency not only in the objections they raise to the proposal, but in acceptance of those rational recommendations made by EPA.

Commenter (0738-Exxon Mobil Corporation) explains that while voluntary efforts by individual companies are important, they only capture a fraction of industry's overall emissions. Full industry participation is required to maximize the benefits to society. Accordingly, based on their experience and expertise, the commenter supports EPA's proposal to strengthen its current LDAR methodologies and programs and expand the scope of regulation to cover all sources not currently included (*e.g.*, liquids unloading, pneumatic pumps and associated gas from oil wells). The commenter also recognizes the importance of technical expertise, training, documentation, and related requirements. The commenter looks forward to further discussions on the best means to meet EPA's goals to enhance upstream monitoring performance.

Commenter (0807-BP) supports reducing methane emissions as a key lever in efforts to combat climate change. Methane currently accounts for around one-fifth of man-made global GHG emissions. In the United States, the oil and natural gas industry is the second largest aggregate source of anthropogenic methane emissions after the agriculture sector (including livestock and manure emissions).<sup>39</sup> The Intergovernmental Panel on Climate Change estimates that the global surface temperature was 1.09-degrees Celsius higher in 2011-2020 than in 1850-1900, with methane emissions contributing about one-half (0.5-degrees Celsius) of that warming.<sup>40</sup> As EPA stated, methane has an estimated 100-year global warming potential value of 25, which “indicates that one ton of methane has approximately as much climate impact over a 100-year period as 25 tons of carbon dioxide.” 86 Fed. Reg. at 63,130. Since methane has a shorter lifetime than carbon dioxide, “the emissions of a ton of methane will have more impact earlier in the 100-year timespan and less impact later in the 100-year timespan relative to the emissions of a 100-year GWP equivalent quantity of carbon dioxide.” *Id.* Therefore, curbing methane emissions from oil and gas can have meaningful near-term impacts—both on climate warming and the world's ability to meet net zero by 2050 or sooner.

Commenter (0807-BP) states that for these reasons, the Biden Administration has understandably made reducing methane emissions a key priority. The U.S., along with the U.K. and other nations, was instrumental at the 26th Conference of the Parties<sup>41</sup> in securing a Global Methane Pledge to collectively cut methane emissions across all sectors by at least 30 percent below 2020 levels by 2030.<sup>42</sup> Over 110 countries, representing nearly 50 percent of the sources of global methane emissions, have joined the pledge. President Biden's U.S. Methane Emissions

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<sup>39</sup> Overview of Greenhouse Gas Emissions, EPA, <https://www.epa.gov/ghgemissions/overview-greenhousegases#methane> (last visited Jan. 25, 2022).

<sup>40</sup> IPCC, 2021: Summary for Policymakers. in: CLIMATE CHANGE 2021: THE PHYSICAL SCIENCE BASIS. CONTRIBUTION OF WORKING GROUP I TO THE SIXTH ASSESSMENT REPORT OF THE INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (Valerie Masson-Delmotte, et al. eds., 2021).

<sup>41</sup> The 26th United Nations Climate Change Conference (COP26).

<sup>42</sup> Joint US-EU Press Release on the Global Methane Pledge, THE WHITE HOUSE (Sept. 18, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/09/18/joint-us-eu-press-release-on-the-global-methane-pledge/>; Fast Action on Methane to Keep a 1.5°C Future Within Reach, GLOBAL METHANE PLEDGE, <https://www.globalmethanepledge.org/> (last visited Jan. 4, 2022).

Reduction Action Plan focuses on a whole-of government approach “to identify and cost-effectively reduce methane emissions from all major sources.”<sup>43</sup>

Commenter (0807-BP) supports these methane emissions goals and agrees with the importance of EPA taking regulatory action now. See 86 Fed. Reg. at 63,152 (“The importance of taking action at this time, in accordance with the requirements of CAA section 111, to reduce the enormous amount of methane emissions from oil and gas sources, in light of the impacts on the climate of this pollution, cannot be overstated.”).

Commenter (0807-BP) continues to support the direct federal regulation of methane emissions. A uniform federal regulatory framework, which establishes consistent minimum standards and nationally applicable guidelines, is necessary for the industry. This can increase consumer and regulator confidence that natural gas producers are acting responsibly, and that natural gas production is both safe and efficient. Voluntary actions by energy companies, although significant, are not enough to solve the methane problem and federal regulations help to level the playing field among companies and incentivize action. Moreover, a federal framework helps support the global competitiveness of American natural gas as pressure for more stringent regulations on methane grows outside the U.S. While state regulations are also still important to achieve methane emission reduction goals, an overarching national regulatory framework for methane emissions is preferable to a patchwork of state-by-state approaches.

Commenter (0919-TEP Rocky Mountain LLC) supports and commends the mutual pursuit to reduce emissions and continue to produce current and future clean energy needs of the nation. As EPA establishes guidelines and standards of performance, the commenter implores EPA to do so in an evidence-based and goal-oriented approach that is built to be flexible and allow for creativity. The commenter reminds EPA that an evidence-based approach includes the positive effects of reliable, clean, and affordable energy sources that propel economies and provide the mechanism for the innovation that future generations will employ. Few public health advances rival the advances made possible by clean and local energy.<sup>44</sup>

Commenter (0766-Cheniere Energy, Inc.) believes understanding and improving the environmental performance of our LNG is not just an environmental imperative, but a business one as well, for the commenter and the supply chain partners. To this end, since 2018, the commenter has pursued a climate strategy focused on data-driven scientific and transparent collaboration along the supply chain to better understand the emissions profile and identify strategic and cost-effective mitigation opportunities, including foundational support for the Collaboratory to Advance Methane Science and a Quantification, Monitoring, Reporting, and Verification collaboration.

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<sup>43</sup> Fact Sheet: President Biden Tackles Methane Emissions, Spurs Innovations, and Supports Sustainable Agriculture to Build a Clean Energy Economy and Create Jobs, THE WHITE HOUSE (Nov. 2, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/02/fact-sheet-president-bidentackles-methane-emissions-spurs-innovations-and-supports-sustainable-agriculture-to-build-a-cleanenergy-economy-and-create-jobs/>.

<sup>44</sup> See, e.g., World Health Organization, About the Health and Energy Platform of Action, <https://www.who.int/initiatives/health-and-energy-platform-of-action/about-the-health-and-energy-platform-ofaction>.



Commenter (0766-Cheniere) believes that quantifying, monitoring, and reducing methane emissions across the U.S. natural gas supply chain are vital to ensure that natural gas and LNG continue to accelerate the global transition away from more polluting fuels and towards a lower-carbon future. Federal regulations on methane can help drive emissions reductions and ensure the long-term sustainable role of U.S. LNG in helping countries meet their climate goals through verifiably lower methane emissions — something the commenter supports and has been proactively working to advance.

Response I-23-25: These comments are supportive comments for EPA’s proposals; as such, no response is required.

Comment: Several commenters (0199-Allergy & Asthma Network, 0216-Montana Health Professionals for a Healthy Climate, 0317-Essential Information, Inc, 0340-Mothers & Others for Clean Air, 0401-Mercy Investment Services Inc, 0402-Cancer Free Economy Network, 0440-Holy Spirit Missionary Sisters, 0414-Waterspirit, 0421-Big Thicket Biosphere Reserve, 0443-Seventh Generation Interfaith Inc, 0444-Damascus Citizens for Sustainability, 0458-MDE, 0559-State of Texas, 0578-Grand Canyon Trust, 0720-Miller/Howard Investments, Inc, 0721-Moms Clean Air Force, 0724-Boston Trust Walden, 0728-Calvert, 0734-American Thoracic Society 0735-Chesapeake Bay Foundation, 0746-Methane Action, 0796-Asthma and Allergy Foundation of America – Michigan Chapter, 0812-Ohio Farmers Union, 0828-Union of Concerned Scientists, 0837-Clean Water Action, 0840-Navajo Nation, Counselor Chapter House, 0920-We Act for Environmental Justice, 0947-23 Different Advocacy Groups, 0949-Liveable Arlington, 1247-Healthy Air and Water Colorado, 1267-The State of California, 1283-Green Arlington Foundation, 1372-General Capital, 1338-Lexington Climate Action Network, 1383-Interfaith Power & Light New Mexico, 1388-William Limpert, 1389-VERIS Wealth Partners, PBC,) support EPA’s proposed rules as a first step towards cutting methane emissions, and generally ask EPA to strengthen the proposal and any further rules involving methane and the oil and gas industry. Examples of some of the comments provided are included in the following paragraphs. Any detailed comments on support for recommended specific changes to the proposed requirements for emission sources provided by these commenters are provided in the relevant Chapters of this document.

Commenter (0578-Grand Canyon Trust) suggests EPA strengthen the rule by consulting directly with Native Americans, strengthening inspection requirements of oil and gas wells, eliminating the wasteful practice of routine flaring at oil and gas sites, and expanding these requirements to abandoned and orphaned oil gas wells. The commenter states that this would help reduce waste and improve the collection of royalties.

Commenters (0216-Montana Health Professionals for a Healthy Climate, 0421-Big Thicket Biosphere Reserve) suggest eliminating loopholes for older, grandfathered operations and end flaring from oil and gas facilities.

Commenter (0947-23 Different Advocacy Groups) suggests strong methane protections like those adopted in Colorado and those adopted or set to be adopted in New Mexico. The commenter notes that these national-leading protections include a prohibition on routine flaring, frequent inspections for all well sites regardless of emission thresholds, increased inspections to

protect disproportionately impacted communities and those living closest to well sites, and strong requirements to retrofit existing oil and gas well sites with zero-bleed or zero-emission pneumatic devices.

Commenter (0734-American Thoracic Society) believes that EPA needs to go further on this rulemaking to tackle environmental injustice, mitigate the disproportionate emissions from small companies, “super-emitters,” abandoned wells and mines, and flaring, and increase monitoring networks and citizen science initiatives.

Commenter (0578-Grand Canyon Trust) urges EPA to heed the warnings of climate experts around the world and to consult directly with Native American tribes and nations regularly to do everything that it can to reduce dangerous methane and other GHG emissions across the country. In the context of this proposed rulemaking, the commenter asserts that EPA must conduct quarterly monitoring at all facilities, including those where site-level baseline methane emissions are below 3 tons per year (tpy), prohibit routine flaring at oil and gas sites, and require monitoring and plugging at abandoned and improperly plugged oil and gas wells.

Commenter (0840-Navajo Nation, Counselor Chapter House) supports the Federal EPA's efforts to cut methane and other harmful pollutants and calls on EPA to strengthen its final oil and gas air pollution rules by enacting a ban on routine flaring and eliminating loopholes that allow certain wells to forgo any regular inspections and requiring monitoring at smaller, leak prone wells.

Commenter (1388-William Limpert) finds that the proposed rule does not go far enough in reducing methane and pollutant emissions from the oil and gas industry. The commenter would like to see more stringent controls resulting in far less emissions, and with those emissions being completely prohibited in the very near future. The commenter adds that testing soil, groundwater, and air should be conducted on a routine basis near compressor stations.

Commenter (0317-Essential Information, Inc) supports the proposed rule, but also suggests that there are several aspects that should be changed or improved. Wells that emit less than 3 tpy of methane should be subject to twice-a-year OGI monitoring. EPA should mandate bonding requirements for each new oil and gas well, of an amount sufficient to cover periodic monitoring, the full future costs of plugging and dismantling wells, and the complete restoration of the well site. Owners/operators should be required to plug wells that are non-producing for four years. EPA should significantly restructure its proposed complaint mechanism. Finally, as a policy matter, the commenter recommends that the Biden Administration assess how the use of natural gas could be totally phased out in order to greatly reduce methane and carbon dioxide emissions to prevent climate change.

Response I-23-26: While these commenters generally support the development of the NSPS OOOOb and EG OOOOc rules, they urge EPA to do more to reduce methane and VOC emissions from the oil and natural gas industry. As discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and

Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior EPA regulations or states' regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

In response to comments that the EPA should end wasteful flaring, the EPA, as a result of information provided through the public comment process, is finalizing revisions to the proposed requirements to limit routine flaring of associated gas. During the comment period, the EPA received extensive information regarding the availability and cost-effectiveness of alternatives to routine flaring, state-level requirements to limit or prohibit routine flaring, and commitments that owners and operators have already made voluntarily to phase out routine flaring in the near future. Based on this information and the EPA's updated BSER analysis, the EPA is finalizing requirements to prohibit routine flaring of associated gas from newly constructed wells that are developed after the effective date of the final rule.

Comment: Commenter (0753-IGSD et al) applauds EPA for taking this first step, expresses general support for the proposed standards and guidelines, and offers here a set of recommendations to make this regulation even more effective and better aligned with existing best practice and ambition for achieving critically necessary methane emissions reductions. The commenter also recognizes the current administration for leading global efforts to achieve methane reductions in numerous sectors, as witnessed by the U.S. promoted Global Methane Pledge announced in Glasgow at COP26, to work to reduce global methane emissions by at least 30 percent below 2020 levels by 2030. In this spirit and because methane emissions reductions are the single most effective pathway to slow the rate of warming over the next two decades, the commenter urges EPA to issue a strengthened final rule that will lead to even greater methane reductions. Finalizing more stringent regulations will meet EPA's CAA mandates<sup>45</sup> and related obligations to protect public health, safeguard the environment, and tackle climate change with the urgency warranted, including as expressed in Executive Order 13,990.<sup>46</sup>

Commenter (0753-IGSD) focuses on provisions for which the commenter urges EPA to act on the best available science and adopt the best available and tested practices, technology, and policies, to ensure that the final rule—provides the most reduction of methane emissions practicable; achieves the U.S.'s international methane goals; and protects communities and ecosystems from the severe impacts of methane and associated pollutants. Specifically, the commenter makes three priority recommendations for the supplemental proposal and final rule:

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<sup>45</sup> E.g., Clean Air Act § 101(b)(1), 42 U.S.C. § 7401(b)(1); Clean Air Act § 111(a)(1); 42 U.S.C. § 7411(a)(1).

<sup>46</sup> Exec. Order. No. 13,990, 86 Fed. Reg. 7037.

(1) to require effective monitoring of all sources; (2) to ban routine flaring; and (3) to use EPA's broad authority in CAA §111 to promulgate strong standards for abandoned and unplugged wells.

Commenter (0753-IGSD) restates the goals of the Global Methane Pledge, including the reduction of methane by 30 percent by 2030, which would reduce warming by 0.2°C by 2050 and keep the 1.5°C target within reach.<sup>47</sup> According to the Proposed Rule's RIA, average annual reductions between 2023–2030 would be 2.75 million short tons of methane.<sup>48</sup>

The commenter (0753-IGSD) believes that while this is a good start, it is likely too low to meet the US's commitment under the Global Methane Pledge. Because the largest extent of methane abatement can occur within the oil and gas sector, sectoral emissions must be reduced by over 50 percent to ensure overall methane emissions are reduced by 30 percent. As a co-lead with the EU and signatory to the Global Methane Pledge, and because climate actions by the US can influence other large emitter countries, the U.S.'s domestic actions must align with reducing global emissions by 30 percent.

Commenter (0753-IGSD) suggests that the U.S. should reduce oil and gas methane emissions to the greatest extent possible, particularly when low- or no cost technology and best practices are available. Methane emissions reduction potential in the sector are estimated to be around 65% below 2012 levels,<sup>49</sup> and even greater when additional sources like abandoned wells are included. Promulgating stringent oil and gas methane emissions reductions requirements—as part of the Biden Administration's larger agenda on methane<sup>50</sup>—will set the world on the path to achieving the Global Methane Pledge's goals.

Commenter (0753-IGSD) points out that on many occasions, the U.S. has taken a bold stance to reduce methane emissions. In the North America Climate, Clean Energy, and Environment Partnership, the United States committed to a 40–45 percent reduction in methane emissions from oil and gas by 2025.<sup>51</sup> At the 2021 North American Leaders' Summit, the United States, Canada, and Mexico pledged to create a North American Strategy on Methane and Black Carbon, targeting all sectors and especially oil and gas.<sup>52</sup>

Commenter (0753-IGSD) believes that EPA's Proposed Rule does not appear to put the U.S. on track to meet the original 40–45 percent goal. By 2025, the commenter notes that the RIA projects that the Proposed Rule would reduce methane emissions by only 13.5 MMTCO<sub>2</sub>e cumulatively. The commenter notes that stricter measures by EPA, complemented by other

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<sup>47</sup> U.S. Department of State (11 October 2021) Joint U.S.-EU Statement on the Global Methane Pledge.

<sup>48</sup> EPA (2021) Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 2-30, tbl. 2-6.

<sup>49</sup> Clean Air Task Force (December 2020) Reducing Methane from Oil and Gas.

<sup>50</sup> See generally White House Office of Domestic Climate Policy (2021) U.S. Methane Emissions Reduction Action Plan.

<sup>51</sup> The White House (29 June 2016) Leaders' Statement on a North American Climate, Clean Energy, and Environment Partnership, Press Release.

<sup>52</sup> The White House (18 November 2021) FACT SHEET: Key Deliverables for the 2021 North American Leaders' Summit.

actions outside of the scope of this rulemaking, are needed to decrease emissions from this sector to meet the 40–45 percent reduction target by 2025.

Similarly, commenter (0788-350 Seattle) states that more than 100 countries signed the Global Methane Pledge at COP26, agreeing to cut their methane emissions by 30 percent. While EPA’s Proposed Rule to reduce methane emissions from the oil and natural gas sector is an important step towards meeting this pledge, the rule does not go far enough, and must be strengthened in order to protect communities on the frontlines of oil and gas development and confront the climate crisis head-on.

Commenter (0864-Dayenu Circle of Jewish Silicon Valley) states that the U.S. and the rest of the world are already far behind in halting the climate crisis. Halting methane emissions is an important step in having a livable planet. The commenter notes the pledges to eliminate methane emissions at COP26. They state, however, that methane can hold 86 times more heat in the atmosphere than CO<sub>2</sub>. But methane lasts only about a decade, while CO<sub>2</sub> can remain for 100 years. By eliminating methane emissions, it can positively impact the climate crisis more quickly.

Response I-23-27: See Response I-23-26 of this Chapter.

Comment: Commenter (1295-Public Land Solutions) recommends that EPA strengthen its proposed methane rule. While this proposed rule is a great start, it can be improved by ending the wasteful and dangerous practice of routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already. Routine flaring burns natural gas as a waste product, emitting a host of climate and health-harming pollutants. Routine flaring should only be allowed in emergency situations. In addition, EPA’s Methane Rule should require regular monitoring at all smaller, high-polluting and leak-prone wells, and work to incorporate emission monitoring results generated by community groups and other third parties to help address major leaks. Cleaning up oil and gas methane pollution is critical for improving air quality, protecting public health, and ensuring that communities across the country retain the opportunity to diversify their economies and pursue economic benefits that result from protected landscapes and the outdoor economy.

Commenter (1295-Public Land Solutions) applauds EPA’s draft rule and urges the agency to set even stronger standards, eliminate loopholes for smaller operations, and end venting and flaring from oil and gas facilities. Finally, EPA should finalize this methane rulemaking as quickly as possible as climate change is an emergency, and our planet cannot afford further delay.

Response I-23-28: See Response I-23-26 of this Chapter.

Comment: Commenter (1160-United Methodist Women of the Desert Southwest Conference) urges EPA to strengthen the rules that reduce toxic air pollution. The commenter asks for rules written to encourage a transition to clean, renewable energy that can reach a target of 70 percent renewable energy by 2030 and 100 percent by 2050, based on 2010 levels. The rule should encourage the modernization of crumbling infrastructure and support the decarbonization of transportation. The rule should also support a just transition for disproportionately impacted

workers and communities. The end goal is 100 percent renewable energy, clean transportation, and a just transition. Thank you for writing rules that cut fracking's climate and toxic air pollution. Thank you for writing and strengthening rules so that our goal of Just Energy for All will become a reality.

Response I-23-29: See Response I-23-26 of this Chapter.

Comment: Commenter (0877-Embankment Preservation Coalition) asks EPA to support the reduction of methane emissions in the natural gas and oil supply chains and require methane measurement from all components of each supply chain. Reporting methane emissions as 100-year carbon dioxide emissions equivalency should be discontinued. All measurements across the entire oil and natural gas supply chains should be required to be provided in actual methane emissions (in pounds and or in tons). The rule should also include all methane emissions, including the unburned methane emitted from the exhaust smokestacks from natural gas-fired compressor units, generators, and boilers located at many compressor station facilities.

Commenter (0877-Embankment Preservation Coalition) states that methane and all hazardous air pollutants emitted from natural gas and oil facilities must be fully reported. Regardless of claimed reported methane emissions, facilities should be required to perform actual baseline methane measurements annually during peak load periods. Reducing methane pollution is one of the most effective things we can do to mitigate climate change in the short run. The commenter urges EPA to make these critical rule improvements and enforce stronger reporting of methane emissions.

Response I-23-30: With regards to suggestions to (1) require methane measurement from all components of each supply chain in actual emissions, and (2) require methane and all hazardous air pollutants emitted from natural gas and oil facilities be fully reported, the reporting of emissions, methane emissions information is reported under the GHGRP and hazardous air pollutants information is included in the National Emissions Inventory (NEI) and is not within the scope of this rulemaking.

The GHGRP requires reporting of GHG data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO<sub>2</sub> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year.<sup>53</sup>

The NEI is a comprehensive and detailed estimate of air emissions of criteria pollutants, criteria precursors, and hazardous air pollutants from air emissions sources. The NEI is released every three years based primarily upon data provided by State, Local, and Tribal air agencies for sources in their jurisdictions and supplemented by data developed by the US EPA. The NEI is built using the [Emissions Inventory System](#) (EIS) first to collect the data from State, Local, and Tribal air agencies and then to blend that data with other data sources.<sup>54</sup>

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<sup>53</sup> <https://www.epa.gov/ghgreporting>.

<sup>54</sup> <https://www.epa.gov/air-emissions-inventories/national-emissions-inventory-nei>.

In response to comment that reporting methane emissions as 100-year carbon dioxide emissions equivalency should be discontinued, see Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.2 (Global Warming Potential (GWP) of Methane), Response I-20-8, for EPA's response supporting the use of the 100-year GWP value.

Comment: Commenter (0789-Pennsylvania Department of Environmental Protection (PDEP)) supports EPA's efforts to significantly reduce GHG emissions, particularly methane, and other harmful air pollutants from the Crude Oil and Natural Gas source category. When finalized, the proposed rule will support state efforts to meaningfully address the harmful impacts of climate change and further protect human health and welfare and the environment. In particular, the proposed rule will assist Pennsylvania in achieving its goal of reducing net GHG emissions from 2005 levels by 26 percent by 2025 and 80 percent by 2050.<sup>55</sup> Pennsylvania's climate change goal is aligned with the reduction targets under the Paris Agreement aimed at keeping global temperature rise below the 2-degree Celsius threshold.

Commenter (0789-PDEP) reiterates that as noted by EPA, the Oil and Natural Gas Industry is the United States' largest industrial emitter of methane. Methane is a potent GHG with a global warming potential more than 28 times that of carbon dioxide over a 100-year period. As methane is the main component of natural gas, it is crucial to address emissions from this source category. Reducing human-caused methane emissions, such as controlling natural gas leaks and releases as proposed by EPA, would contribute substantially to global efforts to limit temperature rise, aiding efforts to remain well below the 2-degree Celsius threshold.

Commenter (0789-PDEP) states that Pennsylvania has been a leader since 2013 in establishing protective and cost-effective conditions for oil and natural gas sources. As such, the commenter supports EPA's efforts to significantly reduce methane emissions from the Crude Oil and Natural Gas source category

Response I-23-31: The EPA acknowledges and commends Pennsylvania in establishing protective and cost-effective conditions for oil and natural gas sources. These comments are supportive comments for EPA's proposals; as such, no response is required.

Comment: Commenter (0574-Consumers Energy Company) would like to highlight two specific issues. First, the commenter supports and reasonable regulation of methane and VOC emissions from the upstream oil and natural gas sector. Clear and reasonable regulation helps keeps natural gas affordable for our ratepayers. In addition, the commenter supports reducing methane emissions in accordance with the recommendations from scientific bodies like the Intergovernmental Panel on Climate Change (IPCC) and their own publicly announced methane reduction goal of net-zero methane by 2030. Under this goal, the commenter has made significant progress in reducing methane emissions from their natural gas delivery system and will continue to support methane reduction efforts from the upstream natural gas sector.

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<sup>55</sup> Executive Order 2019-01, Commonwealth Leadership in Addressing Climate Change and Promoting Energy Conservation and Sustainable Governance, codified at 4 Pa. Code §§ 5.1001—5.1009.

Response I-23-32: The EPA commends the commenter for making significant progress in reducing methane emissions. The EPA considered this and other comments.

Comment: Commenter (0186-Environmental and Natural Resources Department, Snoqualmie Indian Tribe) supports sharply reducing pollution as proposed, by expanding and strengthening NSPS for methane and VOCs from new, modified, and reconstructed oil and natural gas sources, and by establishing the first EGs requiring regulation of methane from hundreds of thousands of existing sources nationwide. These existing sources include significant industrial and commercial sources which have been left unregulated for far too long. Industrial and commercial sources of pollution must be required to pay for mitigating their own impacts, which should be built into their own business structures, and this should occur without perseveration or delay.

Response I-23-33: These comments are supportive comments for EPA's proposals; as such, no response is required.

Comment: Commenter (0751-Pennsylvania Environmental Council (PEC)) urges EPA to advance strong, comprehensive rules to address methane emissions from the oil and gas sector. It is critical that EPA promptly implement effectual standards to address these emissions; this includes regular leak detection and repair requirements for smaller, leak prone wells. As noted above, these lower-producing wells constitute a significant percentage of methane emissions in Pennsylvania and the nation, and the number of these wells is growing every single year. This is an emissions problem that will continue to get worse if not properly addressed. Under the current EPA proposal, operators that calculate lower potential emissions (less than 3 tons per year of methane) could avoid all monitoring after just one initial inspection. This situation is untenable. Rigorous monitoring and repair requirements that reduce emissions by 80 to 90 percent (consistent with EPA's estimates for quarterly to monthly inspections) must apply comprehensively across all facilities. Without regular inspections, these smaller sites could emit pollution into the atmosphere and nearby communities undetected.

Response I-23-34: These comments are supportive comments for EPA's proposals; as such, no response is required.

Comment: Commenter (0741-United Methodist Women) states that monitoring, reporting, and verification standards have a crucial role in providing accurate data on methane leakages and dictating where action needs to be taken. EPA should develop community monitoring programs that engage with frontline communities, educate and certify community members and require immediate follow up on complaints filed by those certified community members. EPA must strengthen the proposed rule to protect public health and the climate and use all its authority under Clean Air Act § 111(d) to cut methane pollution from oil and gas development by 65 percent by 2025. It is common knowledge that methane pollution increases the threat of climate change and negatively impacts air quality. Black, Indigenous, Latino, Asian, and low-wealth communities, will be forced to deal with the worst impacts of both climate change and methane pollution. The commenter urges EPA to act urgently to address this climate injustice to ensure that the health of God's creation and God's people is protected.



Response I-23-35: In response to comments that EPA should develop community monitoring programs that engage with frontline communities, educate and certify community members and require immediate follow up on complaints filed by those certified community members, while the EPA did not develop the community monitoring program that the commenter envisioned, the EPA developed the Super Emitter Program under the final rule.

Please see section X.C of the final rule preamble for a summary of the final requirements under the Super Emitter Program. As described in section IV.C of the December 2022 Supplemental Proposal preamble, the EPA proposed the Super Emitter Program to ensure that this rulemaking comprehensively addresses the widespread problem of abnormally large emissions events known as super-emitters. The EPA is including the Super Emitter Program in this final rulemaking, previously proposed as the Super Emitter Response Program in the December 2022 Supplemental Proposal. The EPA has developed this program in response to recent studies, which indicate that a small portion of sources contribute almost 50 percent of the methane emissions in the oil and gas sector, and on a global scale, the largest of these emissions sources may represent as much as 12 percent of global methane emissions from oil and gas production. For purposes of this rule, a super-emitter event is one that has a quantified emission rate of 100 kg/hr of methane or greater. As described in the final rule preamble, this program is designed to provide a transparent, reliable, and efficient mechanism by which the EPA will provide owners and operators with timely notifications of super-emitter emissions data collected by the EPA-certified third parties using the EPA-approved remote sensing technologies (*e.g.*, satellites). Where such an event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc), the responsible owner or operator will take action in accordance with the applicable regulation.

Lastly, as discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior EPA regulations or states' regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

Comment: Commenter (0444-Damascus Citizens for Sustainability (DCS)) urges the adoption of modifications that would aid in adequately protecting our air resources. Most important is to establish at least a mile and a half, better [would] be two mile geographic area around a facility

seeking a permit within which there is an addition of total accumulation - aggregation - of air pollutant emission sources must be taken into account, as opposed to just permitting each site based on the emissions of that single-point source of pollutants. The point source approach avoids the area designation of 'major sources' and then the avoidance of proper modifications to reduce emissions - or not allow the facility's placement. Protection of public health and environmental health must be the paramount reasoning for regulations. Climate impacts must also be recognized which can only be done if all emissions in an area are added together.

Commenter (0444-DCS) provides the example that in Pennsylvania: Due to the topography of PA, many areas have poor air quality. With the increasing presence of the gas industry, a change for the worse is certainly headed our way. A variety of emissions are emitted at compressor sites: NO<sub>x</sub>, CO<sub>2</sub>, VOC, Formaldehyde, PM<sub>10</sub>, Ethane, Methane, Propane, I-butane, n-butane, Non-Methane Hydrocarbons, Heavy Non-Methane and Non-Ethane Hydrocarbons, etc. Compressors, pits, pipelines, gas wells emit a mix that can create ground level ozone that will regularly be held in place by the air inversion factor we see in our valleys and hollows where we live.

Commenter (0444-DCS) suggests that total toxic accumulation - aggregation - of air emission sources must be taken into account, as opposed to just permitting each site based on the emissions of that single-point source of pollutants. What might this mean to our family, especially children, the elderly and those with respiratory challenges is that the materials emitted in the exploration and development of gas and oil wells have profound health effects. The health effects of air pollution - asthma in children and adults, other forms of compromised lung function, all the effects of absorbed and ingested contaminants that produce multiple health effects - must be of prime importance in considering this legislation.

Commenter (0444-DCS) asks EPA to take a look at this paper and take the information in it into account PEER REVIEWED ARTICLE: Natural Gas Operations from a Public Health Perspective attached as AIR-H24263Colborn2011.

With these considerations in mind, Commenter (0444-DCS) urges the following additions to the rule:

1. EPA cannot continue to determine air quality impacts in piecemeal fashion. There needs to be a policy that informs the public and the drillers that EPA will examine multiple sources of all pollution in the aggregate. This policy must cover a single new source of emissions and all potential related sources in the local area. Failure to do so will jeopardize air quality. The commenter urges mile and a half or better 2-mile areas.
2. EPA needs to notify municipalities and the public when new sources of air pollution are installed, even if they are temporary installations. Large pieces of equipment, such as generators, compressors, and pumps generate noise and air pollution that affects local communities.
3. EPA cannot issue exemptions from source permitting requirements where best available control technology is available to control emissions. Flaring to complete gas wells should no longer be exempt. Green or flareless completion is routinely performed in the gas industry and the installation of these should be required and not exempt such emissions.

4. All possible air emissions capture mechanisms must be used in gas and oil drilling - no exceptions - as Best Management Practices.

Commenter (0444-DCS) suggests that the concerns of citizens must be addressed in EPA's air pollution policy. These concerns highlight the need for community-driven, local air monitoring. Gas drilling companies should be required to regularly report pollution levels, as well as equipment malfunctions, leaks, repairs, and the quantity of collected gas that would have otherwise been emitted to the atmosphere. Residents impacted by the oil and gas industry deserve accurate, publicly available real-time air monitoring and to know what nearby industrial facilities are doing to protect public health.

Response I-23-36: The EPA considered these and other comment in developing the final NSPS OOOOb and EG OOOOc rules. As discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior EPA regulations or states' regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

Methane emissions information is reported under the GHGRP and hazardous air pollutants information included in the National Emissions Inventory (NEI) and is not within the scope of this rulemaking. The GHGRP requires reporting of GHG data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO<sup>2</sup> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year. The NEI is a comprehensive and detailed estimate of air emissions of criteria pollutants, criteria precursors, and hazardous air pollutants from air emissions sources. The NEI is released every three years based primarily upon data provided by State, Local, and Tribal air agencies for sources in their jurisdictions and supplemented by data developed by the US EPA. The NEI is built using the Emissions Inventory System (EIS) first to collect the data from State, Local, and Tribal air agencies and then to blend that data with other data sources.

Permitting is not within the scope of this rulemaking. See, however, EPA's discussion in section XV (Prevention of Significant Deterioration and Title V Permitting) of the preamble to the final rule regarding the applicability of permitting requirements.

Comment: Commenter (1388-Private Citizen) asks for the help from EPA in reducing the negative health impacts, and climate change impacts from existing polluting facilities. The commenter believes that EPA should extend many of these rules to existing facilities. If that is not possible EPA should quickly set new rules to substantially reduce GHG and other pollutant discharges from existing facilities within the next 2 years.

Commenter (1388-Private Citizen) provides one example, which is the Mountain Valley natural gas pipeline. This facility is currently approved to transport up to 2 billion cubic feet of natural gas per day. Mountain Valley has stated that they hope to get approval to increase the volume to 2.5 billion cubic feet per day. Allowing Mountain Valley Pipeline and other facilities under facilities that are currently under construction to emit GHGs and other pollutants under current rules is unacceptable. The Mountain Valley Pipeline may still be operating 50 years from now. Best available science tells us that natural gas transmission lines, like the Mountain Valley Pipeline generally discharge 0.3 percent to 0.35 percent of their volume through leaks and intentional discharges. That would mean emissions of 6 to 7 million cubic feet per day while transporting 2 billion cubic feet of natural gas per day, and emissions of 7.5 to 8.75 million cubic feet per day while transporting 2.5 billion cubic feet per day. Over the next 50 years total emissions from the Mountain Valley Pipeline could come close to 160 billion cubic feet if it is allowed to operate under today's insufficient rules. These are only emissions from the pipeline itself, and do not consider upstream emissions through exploration, extraction, and production that this pipeline will enable, or the very large downstream emissions from combustion of the natural gas.

Commenter (1388-Private Citizen) suggests that today's rules are what got us into our climate crisis, and contributed to so many negative health impacts, including childhood asthma, from this industry. They need to be changed now. Although the industry might argue that it is not fair to change rules for a facility that is currently under construction, because it will cost the, more to complete the project. The commenter is arguing that not to do so will cost many lives and untold suffering in the future.

Response I-23-37: See Response I-23-26 of this Chapter.

Comment: Commenter (0882-New Mexico Public Health Association (NMPHA)) states that oil and gas producers should not be allowed to burn, vent or leak methane. Not only is methane a major driver of the climate crisis and a toxic pollutant that poses public health problems, but this practice is also a big waste of natural resources that should be captured and sold. Natural resources belong to the people, and the state should receive the royalties from them that their people are due. These royalties should be going to schools and hospitals instead of going up in flames.

Response I-23-38: See Response I-23-26 of this Chapter.

Comment: Commenter (0832-NMED) suggests the proposed rule supports New Mexico's efforts to reduce VOC and GHG emissions that contribute to unhealthy ozone levels and contribute to climate change.

Commenter (0832-NMED) points out that several ozone monitors in New Mexico show that air quality is approaching or exceeding the 2015 ozone NAAQS. The Sunland Park area in southern New Mexico is currently designated as in nonattainment of the 2015 ozone NAAQS, with an additional seven counties in the state monitoring ozone concentrations at or above 95 percent of the standard. Monitored ozone concentrations increased throughout New Mexico over the last several years, including both of New Mexico's oil and natural gas producing regions in the San Juan and Permian Basins. According to EPA's latest National Emissions Inventory (EPA, 2014 NEI version II), over 80 percent of the emissions in these areas are from oil and natural gas sources. The Carlsbad ozone air monitor (AQS ID # 35-015-1005) in the Permian Basin, which is an area of rapid growth in oil production, serves as a prime example of the air pollution problems facing New Mexico. The design value for ozone at this monitor has elevated from 68 ppb in 2016 to 78 ppb in 2020. 2021 data show some of the highest monitored ozone concentrations recorded in the past decade, indicating this upward trend will continue throughout the state.

To improve air quality in these areas, the commenter (0832-New Mexico Environmental Department) developed the Ozone Attainment Initiative (OAI) and joined EPA's Ozone Advance program. As part of the OAI, the commenter is currently researching options for control measures for all source sectors. EPA's proposed rule will be fundamental to reducing emissions from the oil and gas sector. Without these important reductions, additional counties in New Mexico and other states may exceed the 2015 ozone NAAQS, resulting in additional nonattainment area designations and nonattainment permitting requirements.

Commenter (0832-New Mexico Environmental Department) states that recent photochemical modeling indicates that interstate transport contributes to high ozone concentrations in New Mexico. As a result, New Mexico faces nonattainment designations and increased nonattainment permitting requirements, while many states contributing to these exceedances have taken no action to address their contributions. This further emphasizes the need for strong, federally enforceable emissions standards for the O&G sector to ensure fair and equitable requirements in basins that span state lines.

Response I-23-39: These comments are supportive comments for EPA's proposals; as such, no response is required.

Comment: Commenter (0746-Methane Action) suggests that in the final rule or next proposal, EPA sets out a process for backing methane out of most of its current level of use, production lease sales, and permitting, while retaining sufficient capacity in the mid-term to help provide essential services for those who have no short term options or alternatives in the U.S. or allied countries such as Germany, while at the same time assisting them in making the transition to climate protection and restoration and via renewables, storage, and efficiency. As noted in section 5 above, the scientific and legal basis for this has been established and confirmed by the studies released in just the past few weeks, showing harm throughout the life cycle of oil and gas produced by fracking and related unconventional methods. Thus, for EPA to do anything other than to begin a phase-out, starting with oil and gas produced with these methods within a kilometer of human residences, is to allow by permit unnecessary disease and death of significant proportions.

Response I-23-40: See Volume II, Chapter 2 (Legal Basis for Rulemaking), subsection 2.1.4 (EPA Has the Authority Under the CAA to Establish State Plan Requirements). See also, discussions in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules. The EPA does not have the authority to phase-out natural gas production/use.

## **23.8 Scope of NSPS/EG Oil and Natural Gas Sector Requirements**

Comment: Commenter (0815-AGA) appreciates and supports the proposal to retain the exclusion of local natural gas utility operations from the crude oil and natural gas source category. The commenter urges that this exclusion be clearly stated in the regulatory text for OOOOa, OOOOb, and OOOOc.

Commenter (0928-APGA) requests that clarify that local distribution companies are not subject to the proposed rule. The commenter notes that EPA’s 2016 final rule for NSPS OOOOa (2016 NSPS)<sup>56</sup> defined the “crude oil and natural gas source category” to include “natural gas production, processing, transmission, and storage, which include the well and extend to, *but do not include, the local distribution company custody transfer station.*”<sup>57</sup> However, they suggest that the language of the 2016 NSPS did not make it immediately apparent that LDCs are excluded from the scope of the rule.

Commenter (0815-AGA) suggests that to avoid confusions, EPA should clarify in Section 60.5365a and the corresponding provisions of new NSPS OOOOb and EG OOOOc that the listed types of facilities are subject to the rule only if they are located within the Crude Oil and Natural Gas Production Source category.

Commenter (0815-AGA) states that there is no proposed regulatory text in EPA’s “notice of proposed rulemaking,” and the scope of the existing rule is not clearly described in the current, 2016 version of 40 C.F.R. Part 60, Subpart OOOOa, §60.5365a. That scope provision is intended to answer the question: “Am I subject to this subpart?” A small gas utility or cooperative that does not have an environmental lawyer on staff may not understand that the rule applies only to facilities that are located within the Crude Oil and Natural Gas Production source category as defined in §60.5430a, and that they should turn to the definitions section toward the end of the rule to discover that the source category does not include operations inside and including the LDC custody transfer station, and then understand that the subpart only applies to facilities in the defined source category. Clarifying language was added to section 60.5365a in 2020. At a minimum, the commenter recommends that clarifying language be restored in NSPS OOOOa and should be included in the new scope provisions of NSPS OOOOb and EG OOOOc so that it is clear to anyone asking “am I subject to this subpart” that facilities inside and including the LDC custody transfer station are not subject to the subpart.

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<sup>56</sup> Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Final Rule, 81 Fed. Reg. 35823 (Jun. 3, 2016), available at <https://www.federalregister.gov/documents/2016/06/03/2016-11971/oiland-natural-gas-sector-emission-standards-for-new-reconstructed-and-modified-sources>.

<sup>57</sup> Id. at 1931 (emphasis added).

The commenter (0815-APA) urges EPA to include the following text in section 60.5365a and the analogous scope sections of NSPS OOOOb and EG OOOOc:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas Production source category, as defined in §60.5430a. Facilities located inside and including the LDC custody transfer station are not subject to this subpart.

Response I-23-41: The EPA agrees that, while the definitions section clearly defines the boundaries of the source category, additional clarification in the applicability section of the subpart, in particular with respect to LDC custody transfer, would further help sources to identify if they might be subject to any of the requirements in NSPSs OOOOa and OOOOb and EG OOOOc. Therefore, these rules have been revised to include the following introductory language at 40 CFR 60.5365a and 60.5386c, as well as 40 CFR 60.5365a:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in §60.5430b [or 40 CFR 60.5430a and 60.5430c, as relevant], for which you commence construction, modification, or reconstruction after September 18, 2015, and on or before December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

Comment: Commenter (0813-Black Hills Energy) states that they are currently investigating opportunities to help customers transport their renewable natural gas to consumers. The commenter explains that natural gas produced from renewable sources such as landfills, livestock operations, and wastewater treatment plants is generally accepted as a lower carbon fuel than geologically produced natural gas. The commenter asks that EPA clarify when renewable natural gas could become subject to the requirements of the proposed rule for the natural gas transmission and storage segment. The commenter recommends that the custody transfer point between the natural gas transportation company (NAICS codes 221210 or 486210) and the renewable natural gas producer, be the delineation between the two. They also recommend that any equipment upstream of that custody transfer point, not be considered in the proposed rule for the applicable facility.

Response I-23-42: Renewable natural gas from sources such as landfills, livestock operations, and wastewater treatment plants is not subject to the natural gas transmission and storage segment requirements of the final NSPS OOOOb or EG OOOOc. See the definition of the crude oil and natural gas source category included in both of these rules [40 CFR 60.5430b; 40 CFR 60.5430c]:

*Crude oil and natural gas source category means:*

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Also note that the introductory text to 40 CFR 60.5365b [and parallel language in 40 CFR 60.5386c (without sentence regarding centrifugal compressor facilities)] states:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (i) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in §60.5430b, for which you commence construction, modification, or reconstruction after December 6, 2022. Centrifugal compressor affected facilities listed in paragraph (b) of this section that use dry seals are subject to the applicable provisions of this subpart if construction, modification, or reconstruction are commenced after December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

Comment: Commenter (0742-ADEC) requests clarification of the definition of “onshore”. The commenter notes that, assuming EPA uses the same definitions from NSPS OOOO and OOOOa, as the proposal contains no new definitions to review, the current regulations define “onshore” as:

*Onshore* means all facilities except those that are located in the territorial seas or on the outer continental shelf.

The commenter (0742-ADEC) would like EPA to confirm that no new extensions to the definition of “onshore” are being proposed, and that no expansion of regulated stationary sources to State waters is proposed because this proposal directly uses the term “onshore” without definition.

Response I-23-43: The NSPS OOOOb and EG OOOOc final rules define “onshore” as follows:

*Onshore* means all facilities except those that are located in the territorial seas or on the outer continental shelf.

## **23.9 Recordkeeping and Reporting**

### ***23.9.1 Rule-Related Recordkeeping and Reporting Requirements***

#### **23.9.1.1 Electronic Reporting**

Comment: Commenters (0391-KBIC, 0781-NTAA, 0605-Muscogee (Creek) Nation, 0943-Sault Ste. Marie Tribe of Chippewa Indians, 0833-UMUT EPD) support the use of electronic reporting of performance test reports, annual reports, and semiannual reports and requests that EPA make sure this information, along with other relevant information, is organized and easily accessible to the public. The commenters believe that information on large emissions events should be made public sooner than the annual reporting period.



Commenter (0461-BHE) supports electronic reporting through Compliance and Emissions Data Reporting Interface (CEDRI). Public access to these reports could be addressed through EPA systems using periodic reports submitted to EPA by operators – *i.e.*, EPA could provide the conduit for information to be made available to the public. Without regulatory text or program elements defined, it is unclear what EPA may be considering programmatically to maintain parity between differing optical imaging technologies with different performance objectives and the need for regulatory test methods. EPA also solicits comment on what elements, if any, are appropriate for more frequent reporting. For example, EPA envisions a program where leak size is distinguished (rather than just leak detection) with tiered reporting criteria potentially applying and larger leaks reported sooner than in an annual report. EPA requests feedback on what mechanism would be appropriate for the collection and public dissemination of this information. Again, it is premature to offer specific recommendations until such technologies are in place with standards for their use. However, the commenter recommends operators reporting through EPA (CEDRI) with public access to the data through EPA systems.

Other commenters (0797-NDDEQ and NDIC) suggest that EPA allow any required documentation to be first sent to the states delegated by EPA with the implementation and enforcement authority for the 2021 NSPS Proposal.

The commenters (0797-NDDEQ and NDIC) note that EPA proposes requiring electronic reporting of performance test reports, annual reports, and semiannual reports through the CEDRI. 86 Fed. Reg. at 63,185. For states that have been delegated authority by EPA to oversee the implementation and enforcement of NSPS OOOO and OOOOa, the commenter states that it is currently burdensome to require owners and operators to solely submit documents through CEDRI. The commenter notes that states with delegated authority have no control over CEDRI, and cannot implement state automation, tracking, and other processes for these reports without first either retrieving the data from CEDRI themselves and then uploading the data into their own systems, or by requiring the owner or operators to resubmit the data directly to the state.

Nonetheless, the commenters (0797-NDDEQ and NDIC) support the use of electronic reporting and agree with EPA “that the electronic submittal of these reports in the proposed NSPS OOOOb will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability, will further assist in the protection of public health and the environment, and will ultimately result in less burden on the regulated community.” 86 Fed. Reg. at 63,185. The commenters also agree that “[e]lectronic reporting can also eliminate paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, EPA, and the public.” However, the commenters assert that requiring those reports to be controlled solely through CEDRI undermines many of those goals, requiring states that are supposed to be helped by electronic reporting to instead be burdened by a system over which they have no control of or input into. The commenters agree with the intent of CEDRI but disagree with its implementation.

Commenters (0797-NDDEQ and NDIC) state that CEDRI allows owners and operators to meet their annual NSPS OOOOa reporting obligations by uploading a single report containing all their affected facilities in the U.S. rather than breaking up the report by state, county, etc. The

commenters provide that this creates challenges for North Dakota, which includes several federally recognized Indian Nations, including the Mandan, Hidatsa, and Arikara Nations, which have substantial oil and gas development. The commenters state that they do not have CAA delegation for those areas, and that there is no current way in CEDRI to differentiate locations within tribal boundaries without manually locating each facility suspected to be within those boundaries. In addition, they state that the public cannot generally access reports within CEDRI and instead must wait until such reports have been sent to EPA's WebFIRE repository which is available to the public. WebFIRE itself has a general disclaimer that "[t]hese records and any related attachments may or may not have been reviewed by the state, local, or tribal air pollution agency or delegated authority." As CEDRI reports do not require the commenter's review before being sent to WebFIRE, the commenters suggest that the public may not be certain over the accuracy of the data or if the commenter has even had the chance to review the data beforehand.

Lastly, the commenters (0797-NDDEQ and NDIC) recognize that EPA acknowledges that CEDRI or even EPA's Central Data Exchange itself may suffer outages. 86 Fed. Reg. at 63,185. While most outages are expected to be short-lived, the commenter notes that those related to a shutdown of the federal government may be considerably longer based on the recent historical record. If CEDRI access was cutoff during a prolonged shutdown, this would severely disrupt the work of a delegated state such as North Dakota. The commenters state that WebFIRE (if still online) would be a sufficient backup for past data, however as a shutdown progresses, the more out of date it becomes. According to the commenters, this is especially concerning for CAA compliance work, as air pollution does not stay at a site and allow itself to be cleaned up later.

Commenters (0797-NDDEQ and NDIC) recommend that the proposed rule be simplified to require owners and operators to submit their reports "to the Administrator", as is the general requirement in many other regulations (*e.g.*, NSPS Subpart Kb), and for CEDRI to be the initial point of submission where EPA, not the state, is implementing the program. Should EPA insist on explicitly requiring CEDRI, the commenter suggests that language referencing or based on section 60.4(a) (All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency...) be included instead, to include wording requiring the duplicate be submitted through CEDRI. In this manner, the delegated state can immediately receive the required report independent of CEDRI's status, and EPA will receive the duplicate for their own use. The commenters contend that this flexibility is vital in allowing the commenter and other delegated entities to continue the implementation and enforcement work that is required and expected, both by EPA and the public.

Response I-23-44: EPA acknowledges the commenters' support for electronic reporting. See section X.N (Electronic Reporting) of the final rule preamble for a discussion on EPA's final electronic reporting requirements to increase the ease and efficiency of data submittal and data accessibility. The EPA is finalizing a requirement that owners and operators submit electronic copies of performance test reports, natural gas processing plant semiannual reports, annual reports, and notifications of well closure activities through the EPA's Central Data Exchange (CDX) using CEDRI.

Regarding making information public on large emissions events sooner than the annual report, see section X.C of the preamble to the final rule for a discussion on the final standards for super emitter events.

As noted in the November 2021 Proposal, a description of the electronic data submission process is provided in the memorandum Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules, available in the docket for this rulemaking. As described in that memo, data flows to EPA from owners and operators through CEDRI. Data then flow from CEDRI to WebFIRE. WebFIRE is the public access portal for information that is submitted to CEDRI. Data submitted to CEDRI is not immediately available in WebFIRE; it goes through a processing period, which allows delegated air agencies time to review reports to reduce any errors that may be in the reports before they are made available to the public. Additionally, although there is a statement in WebFIRE that indicates the data may not have been reviewed by the delegated authority, this should not create certainty over the accuracy of the data. EPA notes that the owner or operator is ultimately responsible for the accuracy and completeness of data contained in the report. The owner or operator or their delegated representative must attest to the report's completeness and accuracy when they electronically certify the report in the CEDRI submission process.

EPA disagrees that reports should first be sent to the delegated air agency before it is sent to CEDRI. Reports that are not submitted electronically are required to be sent to the appropriate EPA regional office concurrently with the delegated air agency, not after the delegated air agency reviews the report. EPA is not changing this requirement; we are merely changing the format in which the report is sent. EPA also notes that even without the addition of specific regulatory text in NSPS OOOOb, the requirement to report electronically to CEDRI does not relieve an owner or operator of the obligation in 40 CFR 60.4(b) to submit a copy of the report to a delegated air agency, if the delegated air agency does not wish to receive the report through CEDRI. However, EPA understands that many delegated air agencies do want to receive reports through CEDRI due to the volume of reports expected with this rulemaking (see the next comment as one example) and because it simplifies the reporting process for owners and operators by allowing a single submission for both the EPA regional office and delegated air agency.

Since the development of CEDRI,<sup>58</sup> EPA has worked with delegated air agencies to develop a system that meets their needs as well as the needs of reporting entities. EPA is committed to continuing to find ways to improve CEDRI and the electronic reporting process, and we continue to provide training to delegated air agencies on CEDRI and our other electronic reporting systems. We are continuing to investigate the integration of delegated air agency reporting systems with multiple EPA reporting systems, including CEDRI, and we are investigating tools to help delegated air agencies review submitted data more easily and quickly.

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<sup>58</sup> During the development of CEDRI, EPA initiated a multi-disciplinary, cross-functional integrated project team that included EPA personnel from various offices and representatives from delegated air agencies.

EPA acknowledges that currently there is no way to filter facilities within Indian Nations within CEDRI. This need has been expressed by users, and we are currently investigating the addition of such a filter within CEDRI.

EPA acknowledges that CDX and CEDRI have experienced short outages, which is why we have included provisions for owners and operators to seek reporting period extensions for narrow circumstances. However, we note these outages are not related to government shutdowns. EPA's electronic reporting systems, both CEDRI and WebFIRE, continue to operate, even in the event of a government shutdown.

Comment: Commenter (0763-TCEQ) states that throughout the proposal, EPA is requiring additional components and additional affected facilities to provide annual reporting. The commenter contends that most states will not be able to accommodate this new amount of paper copies. Therefore, investigators must be able to access the reports through EPA's reporting system. The commenter recommends that EPA ensure that their system (CEDRI) is capable of handling this increase in activity.

Response I-23-45: The EPA acknowledges the commenter's recommendation. See also Response I-23-44.

Comment: Commenter (0560-LGIM America) encourages EPA to adopt a reliable reporting framework that investors and other stakeholders can utilize. The commenter contends that easy and reliable access to data is one of the best methods to achieve EPA's goal of empowering stakeholders to assist in identifying and stopping large emission events. As an investor, the commenter reports that they have the ability to leverage their suite of stewardship tools and capital allocation options in order to encourage positive change at laggard companies. But the commenter contends that this can only be done if the data is there to make the initial evaluation.

Response I-23-46: The EPA agrees that having access to data is useful for investors and stakeholders. See Response I-23-44 of this Chapter related to Electronic Reporting required under the NSPS OOOOb and EG OOOOc. Investors and stakeholders can also access methane emissions information from the Greenhouse Gas Reporting Program (GHGRP). The GHGRP requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO<sub>2</sub> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year.<sup>59</sup>

Comment: Commenters (0401-Mercy Investment Services Inc, 0434-Pax World Funds, 0435-Wespath Benefits and Investments, 0443-SGI, 0455-Radio Drama Network Inc, 0460-Trinity Health, 0538-Change Finance, 0723-Ceres) urge EPA to ensure strong methane emission performance standards by crafting a regulation that establishes a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported methane emissions data, and enable us, as investors, to clearly differentiate between leaders and laggards.

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<sup>59</sup> <https://www.epa.gov/ghgreporting>.

Response I-23-47: The NSPS OOOOb and EG OOOOc requirements do not establish a methane emissions reporting framework. See section II.A (Purpose of the Regulatory Actions) of the final rule preamble for a discussion regarding the purpose of the regulatory actions. See also, discussions in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

Investors and stakeholder can access methane emissions information from the Greenhouse Gas Reporting Program (GHGRP). The GHGRP requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO<sub>2</sub> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year.<sup>60</sup>

#### 23.9.1.2 Streamlined Recordkeeping and Reporting Requirements

Comment: Commenter (0598-CER) agrees with EPA's proposal to maintain the reduction in reporting requirements included in the 2020 Technical Rule Revisions. The commenter notes that the preamble did not include regulatory text for the commenter to validate the reporting requirements under the newly proposed rules in order to evaluate if any additional reductions will be beneficial to industry and EPA. The commenter encourages EPA to evaluate the data that is being provided to determine what additional reporting requirements may be eliminated. The commenter suggests that eliminating reporting requirements be based on the data that EPA is using or not using from the large volume that is submitted by obligated parties.

Commenter (0831-AXPC) urges EPA to minimize any unnecessary recordkeeping and reporting requirements that overlap with those of other state, local, or federal agencies. To the extent that one or more other agencies already require companies to record and report identical or substantially similar information, the commenter suggests that EPA deem that recordkeeping and reporting sufficient for purposes of this rulemaking. The commenter notes that this should guide EPA's approach both in its retention of the reforms of NSPS OOOOa from the 2020 Technical Rule, and in its design of new NSPS OOOOb and EG OOOOc.

Commenter (0831-AXPC) believes streamlining recordkeeping and reporting allows for the oil and natural gas industry to continue to comply with the intent of EPA's regulations, while removing unnecessary burdens that do not result in increasing emissions reductions. The commenters suggest that recordkeeping and reporting reforms become even more important as this regulation adds another form of new source (NSPS OOOOb) and will eventually result in state plans for all existing sources (EG OOOOc). As there are multiple regulations that will apply to EG OOOOc sources, the commenters believe that there is the potential for duplication and unnecessary reporting to multiple regulators.

Also, while the commenter (0831-AXPC) states that they will provide suggestions after seeing the proposed regulatory text in EPA's future actions. The commenter notes that they are currently supportive of the recordkeeping and reporting reforms that EPA has implemented since

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<sup>60</sup> <https://www.epa.gov/ghgreporting>.

the development of the NSPS OOOOa program. According to the commenter, it is currently unclear without regulatory text what other recordkeeping and reporting reforms may be necessary to harmonize the multiple overlapping federal and state regulations, but state that they will provide comments within the supplemental proposal comment period.

Response I-23-48: The EPA acknowledges the concerns raised by the commenter. The EPA considered this and other comments received when developing the proposed regulatory text for the NSPS OOOOb and EG OOOOc included under the December 2022 Supplemental Proposal.<sup>61</sup> Based on comments received on the December 2022 Supplemental Proposal rule language and requirements, we reviewed the notification, recordkeeping and reporting requirements in the NSPS OOOOb and EG OOOOc rules to assure that these requirements are the minimum necessary to assure compliance and properly notify regulatory agencies.

Comment: Commenter (0598-CER) suggests that one method to reduce the burden for small businesses is to reduce the documentation requirements for the small businesses. A few suggestions provided by the commenter are presented below:

The commenter (0598-CER) suggests reducing the inspection requirements to AVO and soap bubble inspections will also reduce some of the documentation burden for small businesses. Digital photos or videos and supporting documents for the inspector or OGI camera will not be required.

The commenter (0598-CER) states that EPA could reduce the number of data points that need to be reported each year. For example, the commenter notes that EPA asks if each tank facility has been removed from service or returned to service each year. The commenter states that an operator could only report on the few that changed status instead of reporting on every facility every year. The commenter adds that EPA also asks if a site became an affected facility during the reporting period. According to the commenter, this is another case where the operator should be able to report on the exceptions instead of reporting “yes” or “no” for every site in the report.

Lastly, the commenter (0598-CER) suggests reducing the time period for small business entities to store and maintain records from five years to two years. The commenter explains that document storage, physical or digital, can be time consuming and expensive. As this revision will impact many more small business entities than the 2016 NSPS OOOOa, the commenter believes that maintaining historic records for five years will result in a greater impact.

Response I-23-49: The EPA has not developed different compliance documentation requirements for owners or operators of affected facilities/designated facilities in the final rule requirements established under NSPS OOOOb and EG OOOOc. However, as discussed in Response I-23-48, we reviewed the notification, recordkeeping and reporting requirements in the NSPS OOOOb and EG OOOOc rules to assure that these requirements are the minimum necessary to assure compliance and properly notify regulatory agencies.

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<sup>61</sup> For the proposed NSPS OOOOb regulatory text, see Docket ID Number EPA-HQ-OAR-2021-0317-1551; for the proposed EG OOOOc regulatory text, see Docket Number EPA-HQ-OAR-2021-0317-1552.

We also note that some fields in the reporting form are not required, but are meant to aid in walking users through the entirety of the form.

### ***23.9.2 Other Recordkeeping and Reporting Requirement Suggestions***

Comment: Commenter (0782-BHE) states that they believe the current recordkeeping and reporting requirements in NSPS OOOOa are extensive and adequate, and suggests additional recordkeeping is not warranted for NSPS OOOOb or EG OOOOc.

Commenter (0782-BHE) notes that EPA requested feedback on public access to reporting information, including use of information from and for communities and others. The commenter recommends retaining the extensive and complete reporting and recordkeeping requirements in the current regulation, NSPS OOOOa. Other programmatic approaches that may be under consideration require significant programmatic development before adoption in a rulemaking and implementation. The current reporting and recordkeeping requirements are extensive and adequate and would be effective if retained. The commenter supports developing programs associated with reporting large leaks, developing community programs, and other elements contemplated in the proposed rule via a transparent process that engages operators and other stakeholders, with any additional reporting and recordkeeping criteria as an outgrowth of that process. While it is premature to offer specific recommendations until program elements are formulated, some general comments from the commenter are provided at this time.

The commenter (0782-BHE) notes that EPA solicits comment on what “community use of information” guidelines should entail and whether specific protocols (*e.g.*, permissible detection technologies, data analytics, operator training, data reporting, public access, and data preservation) should govern the collection of such data and whether such data should conform to any type of certification. The commenter recommends ensuring that any technologies or analytics implemented be vetted through a peer review process with standards or methodologies adopted to ensure data quality. The commenter states that the proposed Appendix K criteria likely present unnecessary hurdles for optical imaging technology, but the commenter supports rational performance metrics and training criteria reflected in methods or standards (*e.g.*, EPA test method, ASTM method). Such standards must apply to all users, whether an operator or a third party in the community. The commenter discourages EPA from implementing community-based programs without standardization and quality control criteria in place to ensure data integrity.

At this time, the commenter (0782-BHE) suggests additional or more frequent reporting for NSPS OOOOb and EG OOOOc may not be necessary, and the costs and benefits associated with significant departure from NSPS OOOOa recordkeeping and reporting requirements have not been developed or considered. The commenter supports development and integration of new detection and measurement technologies, but the commenter suggests that all elements of those programs be developed through a systematic, transparent process that engages stakeholders. Reporting and recordkeeping criteria are just one of the many elements of such programs that require additional, thoughtful consideration.

Response I-23-50: The EPA included similar recordkeeping and reporting requirements as included under NSPS OOOOa under NSPS OOOOb and EG OOOOc where the standards /presumptive standards were similar. Otherwise, the EPA considered this and other comments received when developing the proposed regulatory text for the NSPS OOOOb and EG OOOOc included under the December 2022 Supplemental Proposal. Based on comments received on the December 2022 Supplemental Proposal rule language and requirements, we reviewed the notification, recordkeeping and reporting requirements in the NSPS OOOOb and EG OOOOc rules to assure that these requirements are the minimum necessary to assure compliance and properly notify regulatory agencies.

In response to the comment discouraging EPA from implementing a community-based program without standardization and quality control criteria in place to ensure data integrity, see section X.C of the final rule preamble for a summary of the final requirements under the Super Emitter Program. As described in section IV.C of the December 2022 Supplemental Proposal preamble,<sup>62</sup> the EPA proposed the Super Emitter Program to ensure that this rulemaking comprehensively addresses the widespread problem of abnormally large emissions events known as super-emitters. The EPA is including the Super Emitter Program in this final rulemaking, previously proposed as the Super Emitter Response Program in the December 2022 Supplemental Proposal. The EPA has developed this program in response to recent studies, which indicate that a small portion of sources contribute almost 50 percent of the methane emissions in the oil and gas sector, and on a global scale, the largest of these emissions sources may represent as much as 12 percent of global methane emissions from oil and gas production. For purposes of this rule, a super-emitter event is one that has a quantified emission rate of 100 kg/hr of methane or greater. As described in the final rule preamble, this program is designed to provide a transparent, reliable, and efficient mechanism by which the EPA will provide owners and operators with timely notifications of super-emitter emissions data collected by the EPA-certified third parties using the EPA-approved remote sensing technologies (e.g., satellites). Where such an event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc), the responsible owner or operator will take action in accordance with the applicable regulation.

Comment: Commenters (1389-VERIS Wealth Partners, 1372-General Capital, PBC, 0728-Calvert, 0724-Boston Trust Walden, 0720-Miller/Howard Investments) urge EPA to ensure strong methane emission performance standards by crafting a regulation that establishes a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported methane emissions data, and enable investors to clearly differentiate between leaders and laggards.

Commenter (0437-State of NY Comptroller) believes the 2021 November Proposed Rule only partially meets investors' expectations for a robust rule that fully addresses methane emissions. The commenter urges EPA to establish an empirically-based methane emissions reporting framework based on the actual measurement of emissions. Field studies have estimated that EPA's current factor-based methods may undercount methane emissions by as much as 60

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<sup>62</sup> 87 FR 74722.



percent.<sup>63</sup> The commenter suggests that EPA require empirically founded, measurement-based methods for reporting methane emissions, which enables us as investors to better assess methane-related risks.

Response I-23-51: See Response I-23-47 of this Chapter.

Comment: Commenter (0329-350 Colorado) suggests rules that rely on industry self-reporting of emissions give too much responsibility to an industry with a horrendous track record of complying with reporting requirements. The commenter recommends that EPA require real-time, third party monitoring that is made available to community-based organizations, as well as regular, frequent aerial monitoring surveys.

The commenter (0329-350 Colorado) claims that Colorado’s oil and gas operators have a horrendous track record of complying with data reporting requirements. The commenter notes that their claim is evidenced by two performance audits that the state has conducted in recent years:

1. A 2020 Severance Tax Audit found that-
  - 316 of 416 active operators from the period of 2016 to 2018 were found to potentially be in violation for over 51,000 missing or incomplete reports.
  - The Colorado Oil and Gas Conservation Commission could have levied penalties totaling \$308 million for just 30 days of delinquency, and much more if violations exceeded 30 days. However, it failed to collect these penalties.
2. A 2021 Performance Audit of oil and gas production reporting found that-
  - As of 2021, “about 215,000 of the more than 280,000 reports (77 percent) that COGCC listed as delinquent—and intended to follow up on with operators— were more than 5 years old, with some dating back to 1999.”

[The commenter (0329-350 Colorado) includes an attachment to their comments that includes highlight sheets from both of these reports.]

Response I-23-52: The EPA appreciates the commenter’s information. The EPA has not granted the commenter’s request that EPA require real-time, third-party monitoring be made available to community-based organizations, as well as requiring regular, frequent aerial monitoring surveys. However, the EPA has established a Super Emitter Program in the final action. See section X.C of the final rule preamble for a summary of the final requirements under the Super Emitter Program. As described in section IV.C of the December 2022 Supplemental Proposal preamble, the EPA proposed the Super Emitter Program to ensure that this rulemaking comprehensively addresses the widespread problem of abnormally large emissions events known as super-emitters. The EPA is including the Super Emitter Program in this final rulemaking, previously

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<sup>63</sup> Alvarez, Ramon A. et al. “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,” Science, Vol. 361. No. 6398, 2018.

proposed as the Super Emitter Response Program in the December 2022 Supplemental Proposal. The EPA has developed this program in response to recent studies, which indicate that a small portion of sources contribute almost 50 percent of the methane emissions in the oil and gas sector, and on a global scale, the largest of these emissions sources may represent as much as 12 percent of global methane emissions from oil and gas production. For purposes of this rule, a super-emitter event is one that has a quantified emission rate of 100 kg/hr of methane or greater. As described in the final rule preamble, this program is designed to provide a transparent, reliable, and efficient mechanism by which the EPA will provide owners and operators with timely notifications of super-emitter emissions data collected by the EPA-certified third parties using the EPA-approved remote sensing technologies (e.g., satellites). Where such an event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc), the responsible owner or operator will take action in accordance with the applicable regulation.

Comment: Commenter (0941-350 Silicon Valley) requests that EPA's National Emissions Inventory (NEI) figures for methane be improved and made publicly available in a timely way. The Energy Information Administration (EIA) at the U.S. Department of Energy (DOE) produces monthly oil and gas production estimates based on a monthly survey (Form EIA 914) of the major oil and gas producers in the country. This form specifies that flared and vented gas be excluded from the survey. The commenter recommends that EPA request that these amounts be included in the survey. This could easily be done by adding 3 questions to Form EIA 914, requesting separate estimates for the amount of natural gas (1) flared, (2) vented and (3) leaked. Initially most of the answers to these questions will probably be emission factor estimates, but over time they could improve. They would at least start providing timely estimates for both methane and carbon dioxide emissions from the production of oil and gas.

The commenter (0941-350 Silicon Valley) also recommends that the proposed NSPS and EG rules clarify in the final rule that all facilities are required to report separately the quantity of all the methane they flare, vent and leak. The commenter adds that all these emissions whether they are considered to be "unavoidable" due to an emergency or upset, "avoidable" or routine should be reported monthly. The commenter suggests a deadline for reporting these 3 types of emissions for existing facilities, if possible should be January 2025, but no later than January 2026.

Response I-23-53: The request that EPA's NEI figures be improved and made publicly in a timely way is outside of the scope of this rulemaking; as such, no response is required.

With regards to the recommendation that the proposed NSPS and EG rules clarify that all facilities are required to separately report the quantity of methane they flare, vent, or leak, this is not within the scope of EPA's rulemaking. See section II.A (Purpose of the Regulatory Actions) of the final rule preamble for a discussion regarding the purpose of the regulatory actions. See also, discussions in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

Methane emissions information is reported under the GHGRP. The GHGRP requires reporting of GHG data and other relevant information from large GHG emission sources, fuel and industrial

gas suppliers, and CO<sub>2</sub> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year.<sup>64</sup>

## **23.10 Requests for Extension of the 2021 November Proposal/Information Collection Request Comment Period**

### ***23.10.1 Initial Requests for Extension of the Comment Period for the 2021 November Proposal***

Comment: Several commenters (0184-OK Alliance, 0189-API, 0190-NACAA, 0191-GPA, 0192-AXPC, 0200-ODEQ, 0214-U.S. Senate, 0291-AOGA, 0324-CenSARA, 0334-WV Oil and Gas, 0348-IPAA, 0358-KDHE, 0360-ADEC, 0361-WDEQ, 0408-U.S. Congress, 0412-AGA, 0415-INGAA, 0417-NDDEQ, 0418-Railroad Commission of Texas, 0419-TCEQ, 0580-KY Division of Air Quality, 0825-Montana Department of Air Quality, 0829-U.S. Congress, 0936-U.S. Congress) requested that EPA extend the comment period for the November 2021 proposed rule. These commenters suggested that the comment period be extended anywhere from 30 days to 90 days. Examples of some of these requests are presented in the following paragraphs.

Commenter (0190-NACAA) requested that EPA extend the public comment period by at least 30 days and notify the public of the extension as soon as possible and well in advance of the January 14 deadline so commenters may make full use of the additional time. The commenter (0190-NACAA) stated that the provisions contained in EPA's proposal are complex and have significant ramifications. Indeed, the commenter noted that EPA has requested comment and information on a long list of issues that may require modeling or other analyses to understand. Performing these analyses will necessitate longer than the comment period currently allows. The commenter reported that air quality agencies need a minimum amount of time to review the extensive background materials, gather data, consider the impacts of the proposed changes, and prepare comments, and the intervening holiday season will introduce obstacles to the ability of our respective organizations to coordinate and convene discussions for members. To ensure that state and local agencies have an adequate opportunity to review and respond to the proposal, the commenter stated that additional time beyond the 60-day comment period is necessary.

In light of the considerations discussed above, and because there is no statutory or court-ordered deadline associated with the proposed rule, the commenter (0190-NACAA) requested that EPA extend the comment deadline by a minimum of 30 days, to February 14, 2022 (or later) to allow state and local agencies and others to fully consider and respond to the proposal.

Commenter (0189-API) respectfully requested a minimum 30-day comment period extension for the Proposed Rule. The commenter stated that they will be directly affected by the proposed regulations which are a substantial departure from the current regulations and will have significant impacts on our industry's operations. Considerable effort will be required to analyze and understand rule implications, and to develop constructive comments. Further, the commenter noted that EPA has explicitly solicited feedback on over 200 items, all of which will necessitate

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<sup>64</sup> <https://www.epa.gov/ghgreporting>.

sufficient time to analyze, collect any necessary data, and develop thoughtful responses. The commenter also notes that the comment period encompasses the holidays, which can limit available personnel resources during those holiday periods.

Commenter (0189-API) supported the direct regulation of methane for new and existing sources and remains committed to working with EPA and the Administration to identify emission control opportunities that are cost effective, facilitate innovation and further the progress made in reducing emissions. However, trade associations and operators, including the commenter, have resource limitations and it's imperative that they are allowed sufficient time to fully analyze the impact of these regulations.

Commenter (0415-INGAA) requested that the deadline be extended an additional 30 days, allowing interested parties a total of 90 days to comment following *Federal Register* publication. The commenter contended that this extension is necessary because it raises issues arising for the first time. Specifically, the commenter noted that the proposed rule sets forth emissions guidelines for existing sources under section 111(d) of the CAA. The Crude Oil and Natural Gas source category (which is the source category at issue in the proposed rule) has never been regulated under section 111(d) before. Because this is a complex issue of first impression, the commenter stated that an extension of time is needed to ensure all concerned parties have an opportunity to develop meaningful comments on these important issues.

Commenter (0412-AGA) requested that EPA extend the comment period by an additional 30 days, to allow interested parties a total of 90 days to comment following *Federal Register* publication.

As INGAA and API have noted in their similar extension requests, the commenter (0412-AGA) contended that considerable effort will be required to analyze the proposal, evaluate rule impacts, collect, and analyze any necessary data, develop thoughtful responses to the more than 200 questions EPA has posed for stakeholder feedback and develop constructive comments. The commenter reported that many of the same subject matter experts at the association and in their member companies that will be called on for this effort are also working on myriad other agency rulemakings and initiatives relating to GHG reductions and reporting. With this constraint on our resources, they stated that it is critical to be allowed a minimum 30-day comment period extension on the proposed standards.

Commenter (0191-GPA) requested that EPA provide a 30-day extension of the comment period on EPA's Proposed Rule. The commenter noted that the November 2021 proposal provided only a 60-day comment period. According to the commenter, the timeframe is insufficient to permit stakeholders to provide meaningful comment, especially in view of the expansive set of issues for which EPA has explicitly asked for comment. The commenter stated that EPA's own compilation of just the items on which it explicitly solicits input spans 30 pages and includes some 186 separate requests for comment.<sup>65</sup> The commenter noted that the agency must allow stakeholders an adequate opportunity to provide comments, and this includes sufficient time to

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<sup>65</sup> EPA, Proposed Rule Summary of Comment Solicitations (Nov. 1, 2021), available at <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0028>.

actually consider the extensive discussion in the Proposal and addressing the expansive list of specific requests for input.

Commenter (0191-GPA) stated that, in addition, while not offering regulatory text, the Proposal discussed a wide range of contemplated regulatory changes across the newly redefined Crude Oil and Natural Gas source category. Moreover, they added that EPA's proposal discussed new approaches for regulating emissions from both new, reconstructed, and modified sources and the hundreds of thousands of existing sources across the sector not previously regulated by EPA requirements. This included significant new approaches to addressing emissions, as well extensive associated new monitoring, recordkeeping, and reporting requirements. To assess fully, they stated that stakeholders will need to review the record proffered by EPA in support of its Proposal governing different categories and types of equipment across EPA's source category – including the 390-page Technical Support Document (TSD) and associated materials<sup>66</sup> - and attempt to assess the feasibility of the approaches to both new and existing sources, which often present different and complex scientific and economic analyses.

Commenter (0192-AXPC) requested a minimum of 60 additional days for the public to provide comment on the proposal. The commenter stated that EPA would be justified in granting additional time for public comment both in keeping with precedent of significant air rules and to enhance the quality of public comments and thus support the durability of EPA's final product. The commenter stated that the breadth and depth of the issues in the proposal, as well as the estimations of significant cost implications, necessitate additional time to adequately consider and respond to EPA's ask for feedback on how aspects of the proposal enable final regulations, consistent with section 111 of the CAA and that “achieves the greatest possible reductions in methane and VOC emissions while remaining achievable, cost effective, and conducive to technological innovation.” They added that EPA's own summary of just the solicitation requests for comment in the proposal is 30 pages long. The commenter also noted that these are just a small excerpt of the more than a thousand pages that make the proposal package presently subject to a standard 60-day comment period spanning two of the most significant holiday periods of the year.

The commenter (0192-AXPC) stated that for previous NSPS, and other rules of this size and estimated impact, EPA has often granted extended timeframes to allow for more thorough public comment. For example, the commenter noted that the original NSPS OOOO proposal<sup>67</sup> comment period in 2011 was extended to 90 days. Similarly, they added that the later proposal in 2015 to revise the NSPS again and add NSPS OOOOa<sup>68</sup> also had a comment period that was extended to 90 days. In one of the few similar examples of the agency also proposing existing source guidelines under CAA 111(d), the Clean Power Plan (CPP)<sup>69</sup> first proposed in 2014 initially provided for 120 days of public comment, which was extended to nearly six months. The commenter noted that the CPP and EPA's current methane proposal had similar estimated cost

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<sup>66</sup> Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) (Oct. 2021), available at <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0166>.

<sup>67</sup> EPA-HQ-OAR-2010-0505-0002.

<sup>68</sup> EPA-HQ-OAR-2010-0505-4776.

<sup>69</sup> EPA-HQ-OAR-2013-0602-0001.

impacts of roughly \$15 billion and \$13 billion respectively. The methane rules estimate a 74 percent reduction in its targeted emission of methane over year 2005 versus the CPPs estimated 30 percent reduction in its target of carbon dioxide (CO<sub>2</sub>). Just as EPA correctly recognized the cost and emission impacts of the CPP rule warranted additional time for public comment, the commenter believed the same reasoning holds true for the comparable methane proposal. Indeed, the commenter noted that the proposed EG could cover orders of magnitude more sources than the CPP did, which justifies another reason why EPA should afford at least as much time to comment here as it did there.

Commenter (0192-AXPC) stated that further challenging the timeline for developing sufficient public comment is the possibly unprecedented absence of regulatory text accompanying the narrative description that EPA put forth as its Notice of Proposed Rulemaking (NPRM). Absent the ability to clearly see how envisioned requirements will be written into the Code of Federal Regulations, it is considerably difficult for stakeholders to determine with confidence the impacts of the proposal, any unintended consequences, or opportunities to improve the practicality of the rules. Without actual text, the commenter stated that the public is forced to consider the range of options based on assumptions which expands the scenarios that must be analyzed and, at a minimum, requires more time to consider than the standard 60-day timeframe provided.

Commenter (0192-AXPC) pointed out that there are other unprecedented approaches included in EPA's proposal that present a sizeable challenge for the affected industry to understand and the public to comment. For example, the commenter provided that there are multiple vintages of NSPS OOOO that each come with an applicability date for what constitutes "new sources" versus "existing sources" based on the date of proposed regulatory text. EPA's plan revises the earlier vintage NSPS OOOOa for "new and modified sources" under that rules' effective date, while creating a new NSPS OOOOb for "new and modified sources" and a new EG OOOOc for what will be considered an "existing source" under this rule. Thus, the commenter noted that EPA is proposing a dynamic matrix of compliance requirements and applicability dates where the exact same source would be considered both "new" under NSPS OOOOa within CAA 111(b) and at the same time "existing" under EG OOOOc within CAA 111(d). Without precedent for our industry sector or regulatory text to rely on, the commenter stated that the affected industry and the public will struggle to respond with meaningful comment for situations like this one described. For this situation, in addition to extended time for comment on the NPRM, the commenter supported the need for a supplemental rule that includes reopening the current proposed requirements, without being limited to only new potential areas of regulation, and with a comment period that should also be at least 90 days, if not longer, in alignment with other similar rulemakings.

In addition, commenter (0192-AXPC) stated that EPA in its published proposal and during its recent webinars, has emphasized a need for public comment to include a host of information on new and emerging technologies as well as topics not well studied such as emissions from low producing wells. The commenter provided that detailed analysis of the kind EPA is interested in takes considerable time and availability of third-party vendors and analysts.

Commenter (0825-Montana Department of Air Quality) requested that EPA extend the public comment period by at least another 60 days. The commenter noted that the provisions contained in EPA's proposal are complex and could have significant policy and economic implications for the State of Montana.

Commenters (0418-Railroad Commission of Texas, 0419-TCEQ) requested that EPA extend the November 2021 proposal comment period for 60 days or to the end of the yet to be determined 2022 supplemental proposal comment period to allow for states to provide meaningful feedback on the significant amount of information in the proposal, technical support documents, appendices, and regulatory impact analysis.

Commenter (0358-KDHE) requested that EPA extend the public comment period by at least 60 days and preferably through the end of the yet to be determined 2022 supplemental proposal comment period. The provisions contained in EPA's proposal are complex and have significant ramifications for our sources. The commenter's preliminary review indicated to them that the current proposal does not contain enough specific detail while the supplemental proposal may include more details on which the commenter can provide meaningful comment. According to the commenter, the current limited 60-day comment period does not provide the commenter an adequate opportunity to review the information for the Proposed Rule and provide meaningful and fully informed comments on the requested topics given the breadth and complexity of the issues raised.

Commenter (0200-ODEQ) requested a 60-day extension of the deadline to comment on the November 2021 proposed rules. The commenter provided that the proposal requested comment on a wide range of complex and technical issues. To provide time for meaningful review and response to this proposed rule, the commenter requested that the deadline to comment be extended.

Commenter (0200-ODEQ) stated that the challenges posed by the limited comment period are due not only to complexities inherent in the rule proposal, but also to the potential repercussions in the commenter's approach to permitting, compliance monitoring, regulatory enforcement, and emissions inventory reporting. In short, the commenter contended that the proposed rule, if adopted, would have extreme impacts on all aspects of the commenter's program because it will dramatically affect workload, allocation of resources, and budgeting. The commenter added that the reason the proposal poses such an extraordinary challenge is that the commenter's air program is grounded on the assumption that facilities with emission sources are best addressed when the owner or operator of the facility obtains an air quality permit. Currently, the commenter reported that their program covers approximately 13,000 facilities with air quality permits. The commenter noted that Proposed Oil and Gas Methane Rule has the possibility of increasing that number by an order of magnitude if permits are ultimately determined to be necessary for all designated facilities.

Commenter (0200-ODEQ) added that, notwithstanding the complexity of the rule and the substantive requests EPA is making for feedback, the number of facilities in Oklahoma that could be subject to applicable requirements is vast. They explained that states like Oklahoma with such a high potential for extreme changes to their programs need extra time to assess the

true nature of the potential impacts of the rule to the environment, state programs, and to industry. The commenter suggested that, without extension, the comment period does not allow states adequate time to analyze the voluminous background materials compiled in the docket, much less the proposed rule itself. According to the commenter, this lack of adequate review time is compounded by the fact the comment period overlaps with the winter holiday season.

Commenter (0291-AOGA) requested a 60-day extension of the January 14, 2022 deadline for submittal of comments on the performance standards and guidelines proposed for comment at 86 Fed. Reg. 63110 (November 15, 2021). The commenter stated that the proposed rules include sweeping changes to the performance standards and monitoring methods that oil and gas producers must deploy to control and monitor methane emissions in multiple operational sectors. The commenter stated that they had determined that several of the proposed emission limits assume the application of control strategies that may not be feasible in the harsh climatic conditions of the Alaska North Slope. Similarly, the commenter reported that some of the monitoring requirements in the rule may not be realistic or practical for North Slope operations. To the extent that the proposed rules present engineering challenges, the commenter sought to provide to EPA focused and documented comments, including suggestions for alternate compliance strategies that offer high control efficiencies with fewer feasibility constraints. To do so, they intended to bring to bear our members' vast engineering expertise. They asserted that a comment deadline of January 14, 2021, spanning the holiday season, does not provide enough time to marshal the resources necessary to fully develop meaningful comments that will inform EPA's judgment.

Commenter (0184-OK Alliance) requested EPA extend the public comment period for 60 additional days for the Proposed Rule. The commenter suggested that the current limited 60-day comment period did not provide our members an adequate opportunity to review the information and rationale for the Proposed Rule and provide meaningful and fully informed comments on the requested topics given the breadth and complexity of the issues raised. In addition, they noted that the upcoming holiday season limited their members availability to review and provide beneficial information to EPA. The commenter added that the requested extension of time will not cause hardship to EPA. On the contrary, the commenter contended that it would assist in EPA's decision-making process, and noted that there is ample precedent for EPA to provide an extension of time.

Commenters (0359-NDPC, 0802-Kraken) also requested additional time for stakeholders to thoughtfully consider and respond to EPA's Proposed Rule. The commenters acknowledged EPA's desire to advance the public process; however, given the extent of the proposal (*i.e.*, revisions to one existing rule, two new rules, and comment on a future rule), and the many equipment related and technical feasibility challenges that will need to be considered by multiple interrelated stakeholders (*e.g.*, companies within the oil and gas sector and equipment manufacturers), and its timing, they requested a minimum of 60 additional days for the public to be able to provide comment on the proposal.

Commenter (0214-U.S. Senate) urged EPA to extend the public comment period by 60-days for EPA's proposed rule to directly regulate methane emissions from the oil and gas sector. The commenter asserted that the complexity of EPA's proposal, coupled with the holiday season



falling within the comment period, provided ample justification for a 60-day extension of the comment period to March 15, 2022.

Commenter (0324-CenSARA) requested that EPA extend the public comment period by at least 60 days and preferably through the end of the yet to be determined 2022 supplemental proposal comment period. The commenter also requested that EPA notify the public of the extension as soon as possible and well in advance of the January 14 deadline so commenters may make full use of the additional time. The commenter supported their request by noting that the provisions contained in EPA's proposal are complex and have significant ramifications for our members. They added that their preliminary review indicates that the November 2021 proposal does not contain enough specific detail while the supplemental proposal may include more details on which we can provide meaningful comment.

Commenter (0324-CenSARA) added that in this proposal, EPA has requested comment and information on a lengthy list of issues that may require modeling or other analyses to be performed before these issues can be fully understood. The commenter noted that performing these analyses will necessitate a longer comment period than currently proposed. Air quality agencies need a minimum amount of time to review the extensive background materials, gather data, consider the impacts of the proposed changes, and prepare comments. To ensure that state and local agencies have an adequate opportunity to review and respond to the proposal, the commenter provided that additional time beyond the 60-day comment period is necessary.

Commenter (0408-U.S. Congress) urged EPA to grant an extension of time on the initial 60-day comment period for the Proposed Rule. The commenter noted that the implications of the Proposed Rule which applies to both new and existing sources, will expand across the entire oil and natural gas industry. The commenter reported that Wyoming ranks 8th in the nation in oil production and 9th in natural gas production, and as such, Wyoming constituents and the state will be directly affected by the Proposed Rule which represents a significant change to the current regulations. Specifically, the commenter noted that the proposals for existing sources will be difficult to review due to the immediate and broad impacts they will create. As such, they explained that it will require a substantial amount of time and effort to determine the mechanics associated with the Proposed Rule, as well as to gauge the overall impact to the industry. The commenter requested that EPA grant a 60-day extension of the comment period to allow for the time it will take to fully analyze and understand the implications of the proposed rule and to provide meaningful comments.

Commenter (0417-NDDEQ) requested an extension of the comment period for the November 2021 proposed rules to allow sufficient time to review and comment on the complex proposed new rules and guidance. The commenter requested an extension of the public comment period of a minimum of 60 days. The commenter reported that they are the primary state regulatory agency responsible for the protection of North Dakota air quality and for the implementation of the numerous federal and state environmental protection programs. The commenter stated that the proposed new regulations are technically complex. The current comment period does not provide sufficient time to adequately evaluate the impact the proposed new regulations will have on the state of North Dakota, including estimating financial impacts, reviewing for conflicts with

existing state regulation(s), and determining impacts if the state does not agree to implement the rules (*i.e.*, direct EPA implementation).

Commenter (0829-U.S. Congress) stated that the proposed rule includes sweeping changes to the performance standards and monitoring methods that energy producers will need to implement in order to control and monitor methane emissions from new and existing sources, while burdening producers with acute financial burdens. The commenter suggested that EPA has failed to provide a fully developed, well-defined, and easily understandable regulation that can be clearly understood by small businesses and individuals. The commenter asserted that it is necessary to extend the public comment period for an additional 60 days to give the American people more time to comment.

Commenter (0361-WDEQ) requested a 60-day extension of the deadline to submit comments on EPA's proposed rule. The commenter and the State of Wyoming have significant interests in the proposed rule. As of August 2021, the commenter reported that Wyoming ranked eighth nationally in oil production<sup>70</sup> and for the 2020 calendar year, Wyoming ranked ninth in marketed production of natural gas.<sup>71</sup> The commenter noted that they exercise substantial regulatory authority over the operations of Wyoming's extensive oil and gas industry. For example, the commenter stated that their program covers over 18,000 operating single well sites and compressor stations. The commenter stated that the proposed rule introduced a variety of complex technical requirements and revisions that could have significant policy and economic implications for the State of Wyoming, and the current public comment period does not provide nearly enough time for meaningful review and response. The commenter asserted that they needed more time to assess the impacts of the proposed rule and the potentially dramatic increase in permit applications and reviews it could impose on the commenter's staff. In the limited time the commenter has had to review the rule, they expressed that they already had significant concerns regarding the heavy burden the proposed rule would place upon the agency. Rather than reinforce the commenter's efficient, expedient permitting process, the commenter noted that it appears the proposed rule will exacerbate the resource challenges their agency already faces.

Commenter (0361-WDEQ) expressed that EPA is also seeking comment and information on an extensive additional list of subjects, essentially conflating the proposed rule with an ANPR. The commenter noted that the current public comment period does not provide sufficient time to review both the requirements within the proposed rule, and the additional areas that could inform decisions on a final rule or other potential related future rulemakings. For example, on November 1, 2021, EPA released a memo with a 27 page-long Excel table outlining 186 topics and issues for which EPA is soliciting comment and information. The commenter asserted that this places a tremendous burden on states like Wyoming in addition to the work necessary to review the proposed rule itself. The commenter noted that states can provide EPA with important and valuable feedback on these information solicitations, but only if they have significant time for review and develop meaningful feedback. Similarly, the commenter added that the 214-page RIA for the proposed rule is massive/technical and requires additional time for review.

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<sup>70</sup> U.S. Energy Information Administration, <https://www.eia.gov/state/rankingsfillseries/46>.

<sup>71</sup> U.S. Energy Information Administration, <https://www.eia.gov/state/rankingsfillseries/47>.

Finally, the commenter (0361-WDEQ) suggested that the timing of the proposed rule is challenging. It is troublesome that the public comment period for a rule with such significant policy implications, and requiring such extensive review, falls almost entirely during the winter holiday season and the closing weeks of the fourth quarter of 2021. They asserted that there are already staff resource burdens involved with completing required end-of calendar-year reports and other work. Moreover, the commenter reported that staff availability is diminished as a result of the holiday season.

Commenter (0348-IPAA) stated that the proposal document characterized as a proposed rule did not contain proposed regulatory language. The commenter noted that EPA provided 60 days for comments. The commenter added that a 60-day comment period for a true "proposed rulemaking" of one "distinct" regulatory action with proposed regulatory text, is probably typical, with more complex regulatory action providing three to six months to provide comment.<sup>72</sup> The commenter provided that EPA even stated in the first sentence of the "proposed rule" that "this document comprises three distinct groups of actions under the Clean Air Act." According to the commenter, each of these three distinct regulator actions under the CAA warrant at least a separate, non-concurrent 60-day comment period. The notice and comment procedures of the APA are intended to provide "for the public to comment on notices of proposed rulemaking."<sup>73</sup> The APA was designed to provide stake holders adequate time to analyze and provide comment on each and every proposed rule. The fact a proposed regulatory action may be interrelated, and overlap does not justify a typical or ordinary 60-day comment period. To the contrary, according to the commenter, the interrelatedness and complexity of proposing three distinct regulatory actions simultaneously, justify at least a 120-day comment period.

Commenter (0348-IPAA) stated that, in addition to the concerns associated with the "procedural" shortcomings of a 60-day comment period, a 60 day comment period truncates EPA's and stakeholder's ability to adequately and appropriately evaluate a \$1,496,987 taxpayer funded study by the DOE that will provide the most comprehensive data set on emissions from low production wells created to date. Finally, after ten years of effort to have the government gather representative data on low production wells, the DOE is poised to publish its Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells (DE-FE0031702) at the end of this month/early 2022 (the government contractors are to provide their final draft report on or about December 23, 2021 and DOE to release the report in early 2022). The commenter contended that it makes no sense to arbitrarily provide a 60-day comment period effectively precluding adequate review of the best data set yet to be created/released. The commenter stated that the additional 60 days will be meaningless in terms of when certain sources will be regulated and the amount of additional methane that will be released to the environment will be inconsequential. However, for the small businesses relying on low production wells for their livelihood, it could mean their very existence.

Commenter (0360-ADEC) stated that the proposed rule included sweeping changes to the performance standards and monitoring methods that oil and gas producers in Alaska will need to

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<sup>72</sup> American Exploration & Production Counsel Request for Extension of Public Comments (November 23, 2021), EPA-HQ-OAR-2021-0317-0192.

<sup>73</sup> <https://www.epa.gov/laws-regulations/summary-administrative-procedure-act>.

institute to control and monitor methane emissions from non-traditional emission sources. The commenter stated that due to the wide-ranging and deeply technical scope of the proposal, including a period over an extended holiday season, the commenter believed it would be beneficial for all stakeholders if the comment period for the Proposed NSPS Emissions Guidelines for Control of GHG Emissions from the Oil and Natural Gas Sector be extended a minimum of 60 days beyond the original January 14, 2022, deadline.

Commenter (0936-U.S. Congress) stated that EPA's own press release established the extraordinary scope of this proposed rule, as it applied to "existing sources nationwide."<sup>74</sup> The commenter noted that the November 2021 proposal was unprecedented in its scope and breadth. The commenter suggested that EPA expand the comment period no less than 90 days beyond January 31, 2022.

Commenter (0334-WV Oil and Gas) urged EPA to extend the current 60-day public comment period by an additional 90 days. The commenter expressed that the Administration may have moved too quickly in its effort to release the proposed rule in advance of the Glasgow Climate Conference. As such, the commenter stated that the proposed timeframe does not allow adequate time to appropriately review hundreds of pages of new proposed regulations and accompanying documents. Given the importance of this review, the commenter believed it is prudent to allow more time to assess and comment.

Commenter (0580-KY Division of Air Quality) asked for an extension of time due to the extensive nature of this proposal and reduced staffing levels caused by the recent COVID-19 pandemic, the Division recommended a minimum extension of the comment period of at least ninety (90) days is requested.

Commenter (0946-MOGA) asserted that a condensed response time to facilitate an adequate response to EPA and Small Business Administration (SBA) was too short. The commenter reported that, during previous NSPS OOOO and NSPS OOOOa rulemaking events under the Obama and Trump administrations, the duration of response time was much longer and allowed a more in-depth analysis and comprehensive response.

Commenter (0946-MOGA) argued that more time is necessary to address the concerns and comments of the participating Small Entity Representatives (SERs) submitted on July 13, 2021, and following the initial Small Business Advocacy Review (SBAR) panel discussion. The commenter reported that the follow-up SBAR panel needed 2 separate meetings (July 29, 2021 & August 3, 2021) to discuss SER comments. The commenter believed that time constraints limited EPA's response to SER comments and required skipping through material. The commenter expressed that they would have preferred that adequate time would have been provided to address the various comments and concerns and to individually address each source category as it pertains to proposed changes.

Response I-23-54: After consideration of comments received on the November 2021 proposal from industry and states to extend the comment period due to the lengthy and complex nature of

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<sup>74</sup> U.S. EPA Press Office, <http://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health>, January 31, 2022.

the action, EPA extended the public comment period from January 14, 2022, to January 31, 2022. This extension was provided to allow additional time requested by the public to review the proposal and gather and provide information to the Agency.<sup>75</sup>

### ***23.10.2 Follow-Up Requests for Additional Extension of the Comment Period for the 2021 November Proposal/More Time Being Allowed Under the Supplemental Proposal***

Comment: Several commenters (0383-U.S. SBA, 0585-Kentucky Oil & Gas Association, 0598-Countrymark Energy Resources, 0758-Ovintiv Inc, 0778-U.S. Congress, 0788-U.S. Congress, 0810-Petroleum Alliance-OK, 0923-Lambda, 1422-U.S. Congress) requested that EPA extend the comment period for the November 2021 proposed rule beyond the 15-day extension period that EPA provided. Examples of some of these requests are presented in the following paragraphs.

Commenter (0814-IPAA *et al.*) stated that, at the request of the Producer Associations (the commenter) and other stake holders, EPA provided roughly an additional 14 days for comments. While the commenter appreciates the additional time, the commenter asserted that the comment period is still inadequate. The commenter argued that there is no statutory deadline forcing a truncated comment period. Additionally, at the commenter pointed out in their request for additional time to comment, the DOE is poised to produce a study on emissions from low production wells that needs to be reviewed and considered by EPA as it intends to withdrawal certain exemptions for low production wells.<sup>76</sup> The commenter therefore expressed that that they believe the truncated comment period, when EPA is aware of the pending DOE study, was arbitrary and capricious.

Commenter (0585-Kentucky Oil & Gas Association) requested that the original comment period be extended by 45 to 60 days. They reported that EPA granted an extension from January 14, 2022 to January 31, 2022. While they appreciated the additional time, they noted that it is not the 45 to 60 days that was requested.

Commenters (0810-Petroleum Alliance-OK) suggested that the 60-day comment period along with the 15-day comment extension is unreasonable for such a complex rulemaking. The commenter noted that it does not allow our members adequate opportunity to review the information and rationale for the Proposed Rule, and to provide meaningful and fully informed comments on the requested topics given the breadth of the issues raised.

Commenter (0778-U.S. Congress) asked EPA to withdraw this proposed rule pending further environmental and economic study. Barring that, the commenter requested an extension of the comment period beyond the 15 days that EPA extended the comment period, of not less than 60 days, to give the public, regulated community, and other stakeholders the time necessary to analyze the proposal and fully participate in the rulemaking process. The commenter suggested that, as the country continues to recover from the COVID-19 pandemic the U.S. needed to be

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<sup>75</sup> 86 FR 71603.

<sup>76</sup> Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells - Draft Final Project Report, US DOE NETL Award Number DE-FE0031702 (Dec. 31, 2021) - "Attachment C".

working to strengthen American energy production, not burdening the industry with unnecessary and costly regulation.

Commenter (0923-Lambda) asserted that the short review period of 77 days (including two major holidays) did not allow sufficient time for companies to read, evaluate the potential impacts and provide adequate comments regarding the feasibility of the proposed rule. Applicability of new regulations to assets is always challenging but is even more so with vague references to what might be regulated in the future with regards to NSPS OOOOa, NSPS OOOOb, EG OOOOc. The commenter recommended that EPA provide a clear and more concise set of proposed rules and revise the nearly 1000 pages of text that were introduced. Again, the commenter noted that the 577-page preamble and 390-page technical document did not provide specific text or proposed regulations for consideration, leaving companies such as the commenter guessing on what may be required with a lot of gray areas in potential impacts to our small business. The commenter added that providing the commenter's staff the time to read and interpret this depth of information in such a short amount of time is also a hurdle for a small business such as the commenter.

Commenter (0758-Ovintiv) requested additional time to review and comment on what they stated was a complicated rulemaking. The commenter expressed that the 15-day extension provided by EPA is insufficient to provide the public with an adequate opportunity to participate as required under the APA. Moreover, the commenter added that since no regulatory text has been provided in this initial proposal, the commenter's assessment of the proposed standards will likely change once the requirements are clarified in EPA's supplemental proposal.

Similarly, commenter (0788-U.S. Congress) welcomed EPA's decision to extend the comment period but expressed that the extra 16 days provided is not sufficient for relevant stakeholders to provide the substantive comments necessary for a thorough rulemaking process. On top of the inadequate amount of time provided for public comment, the commenter added that the 154-page proposed rule is devoid of rule text and the kind of specificity that the public and regulated community are due.

Commenter (0598-Countrymark Energy Resources) pointed out that EPA granted a comment period extension from January 14, 2022, to January 31, 2022. While the commenter expressed appreciation for the additional time, they noted that it is not the full 60 days that was requested. From the quality of the comments presented, the commenter stated that the proposal was read, and comments were developed for EPA's review. The commenter complained that completing this work in the given time period was a substantial burden on a small team during the end of year holidays and beginning of the year start-up activities.

Commenter (0383-U.S. SBA) believed that the comment period was unreasonably short for the scale and scope of the proposed rule. The commenter suggested that EPA extend the comment period by 45 days (noting that an extension of the comment period by only 17 days was insufficient).

Commenter (0383-U.S. SBA) stated that small businesses and trade associations that represent their interests have expressed their concern that the complexity of the EPA proposal, the open-

ended nature of some of the requests for comments, ambiguities in the proposal due to a lack of regulatory text, and the large number of previously unregulated sources that might be subject to the rule have made it extremely difficult to fully understand and comment on the rule. The commenter provided that small businesses want to contribute to EPA's understanding of the oil and natural gas production industry, correct potential errors in EPA's calculations, and project the unintended negative consequences of this proposal, to industry participants, to their suppliers and customers, and to the environment. However, the commenter stated that this was not possible given the short time frame.

Commenter (0383-U.S. SBA) reminded EPA that there have already been requests for an extension of the comment period from trade associations representing a range of oil and natural gas producers, large and small, and the two major associations representing state clean air regulators. The commenter added that small businesses face the additional challenge that their operations are generally very lean, with regulatory compliance staff already overburdened. The commenter provided that the same staff is being asked to also work on this complicated and voluminous proposal; at the same time the comment period both overlaps with the major holiday season and with a range of end-of-the-year compliance activities. The commenter contends that EPA's extension of the comment period by 17 days ameliorates some of this impact but does not fully address the difficulty that small businesses are having understanding this complex rulemaking.

The commenter (0383-U.S. SBA) suggested that further extension of the public comment period would allow for small businesses to incorporate the results of the highly anticipated study sponsored by the DOE, "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells." During the Small Business Regulatory Enforcement Fairness Act (SBREFA) panel, SERs strongly recommended that EPA delay the proposed rule until EPA could incorporate results of the study into its findings. The U.S. SBA Office of Advocacy (Advocacy) understands that this study should be released by the end of this calendar year. The commenter asserted that a further extension would give small businesses an opportunity to relate the results to their operations.

The commenter (0383-U.S. SBA) expressed that the prospect of a supplemental proposed rule and subsequent comment period are not a substitute for a further extension of this comment period. The commenter stated that EPA has put forward this proposal as is, with the extensive request for comments and complex technical supporting documents. They asserted that EPA should allow for a full consideration of these issues as they are now presented and respond to this public input in the supplemental. They argued that it does not serve the public interest for EPA to work on a supplemental proposal with incomplete information. Similarly, they added that EPA should not rely on future comment periods to justify a decision to not further extend this comment period; any supplemental proposal that does not benefit from the full and considered input of affected small entities is bound to be flawed.

Commenter (1422-U.S. Congress) welcomed EPA's decision to extend the comment period, but the commenter contended that the extra 16 days provided is not sufficient for relevant stakeholders to provide the substantive comments necessary for a thorough rulemaking process. On top of the inadequate amount of time provided for public comment, the commenter stated that

the proposed rule is devoid of rule text and the kind of specificity that the public and regulated community are due.

The commenter (1422-U.S. Congress) noted the environmental and economic implications of this rule and requested that EPA withdraw the proposed rule pending further studies. Barring that, the commenter called for a further extension of the comment period, of not less than 60 days, to give the public, regulated community, and other stakeholders the time necessary to analyze the proposal and fully participate in the rulemaking process. The commenter stated that, as the country continued to recover from the COVID-19 pandemic the U.S. needed to be working to strengthen American energy production, not burdening the industry with unnecessary and costly regulation.

Response I-23-55: As noted in Response I-23-54 of this Chapter, after consideration of comments received on the November 2021 proposal from industry and states to extend the comment period due to the lengthy and complex nature of the action, EPA extended the public comment period from January 14, 2022, to January 31, 2022. (86 FR 71603, December 17, 2021.)

The EPA also notes that while many commenters wanted additional time to provide comment on the November 2021 Proposal beyond the extra 15 days provided, the public also had the opportunity to provide comments on the December 2022 Supplemental Proposal and had access to pre-publication versions of the preambles for both the November 2021 Proposal and December 2022 Supplemental Proposal on EPA's website.

While the prospect of a supplemental proposed rule and subsequent comment period may not have been a substitute for an extension of this comment period beyond the 15 days provided on the November 2021 Proposal, the EPA is appreciative of the significant number of thoughtful and constructive comments provided by the public for EPA to review and consider in the development of the December 2022 Supplemental Proposal.

As for the suggestion that the EPA withdraw the rule, the EPA has not granted the commenter's request. While COVID-19 is still present, the pandemic has ended. See also sections XVI.C (What are the cost impacts?) and D (What are the economic impacts?) of the final rule preamble where the EPA presents a summary of the results of the cost and economic impact and distributional analyses conducted.

### ***23.10.3 Unable to Provide Comprehensive Comments on the November 2021 Proposal Because of Insufficient Time***

Comment: Commenter (0729-EWTC) submits general examples of technologies that can meet the proposed goals; however, they contend that the short initial 60-day comment period, and the two-week extension, have limited the detailed analysis crucial to a regulation of this magnitude. The commenter states that EPA has announced plans to issue a supplemental proposal containing the regulatory text in 2022. The commenter respectfully requests that EPA offer a full and extended public comment period for the supplemental rule to ensure our companies can deliver a



comprehensive analysis of the proposed regulations and the potential implications for our industry.

Commenter (0911-NDPC) acknowledges EPA's desire to advance the public process. However, the commenter states that given the extent of the proposal (*i.e.*, revisions to one existing rule, two new rules, and comment on a future rule) and the lack of detailed rule text, the comments are limited in scope and detail due to the condensed public comment period and the lack of rule text to review. The commenter asks that future rulemakings not be bundled with multiple proposed regulatory actions to give the public and regulated industry the time to participate efficiently and effectively. Silence on any part of this proposal should not be interpreted as our agreement or support. According to the commenter, time constraints have impacted our ability to respond to every piece of this proposal.

Commenter (0742-ADEC) feels that the scope and expanse of this rulemaking proposal, including the widely varying and disparate topics require more than the short initial 60-day comment period, including this meager extension. Oil and gas producers within Alaska are extremely burdened to attempt a highly technical response to this proposal under the current deadline. The commenter hopes that in the next phase of this rulemaking process, EPA will provide adequate time for review so that additional supporting data can be provided for consideration.

Commenter (0810-Petroleum Alliance-OK) requested EPA's forthcoming proposed supplemental rule provide at least a 120-day comment period.

With the short period of time, commenter (0585-Kentucky Oil & Gas Association) reported that they were not able to review all the documents provided by EPA and develop more data driven comments. With the workload that was before them, the commenter added that they were not able to develop the data driven responses to EPA as if the 60-day extension were granted. The commenter asserted that this lack of time to respond with quality feedback is detrimental to their industry. The commenter expresses that several times in prior years, EPA has informed industry that a position was taken on a proposed regulation because of the lack of information provided by industry. The commenter noted that they are submitting this feedback to EPA that the quality of feedback is not available due to the timeline that was granted by EPA.

Response I-23-56: See Response I-23-55 of this Chapter.

#### ***23.10.4 Extension of Comment Period to Review Information Collection Request***

Comment: Commenter (0416-GPA) requested that the OMB provide a minimum of a 30-day extension of the comment period on its review of the ICR in the Proposed Rule. The commenter noted that the ICR component includes detailed reporting and recordkeeping and associated cost information and assumptions.<sup>77</sup> According to the commenter, EPA must allow stakeholders an adequate opportunity to provide comment, and this includes sufficient time to consider the expansive Proposal and related ICR demands.

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<sup>77</sup> E.g., ICR at 5-16; EPA-HQ-OAR-2021-0317-0144\_attachment\_1.

Response I-23-57: The comment period for review of the Information Collection Requests (ICRs) developed in support of the November 2021 Proposal was not extended.

### **23.11 Other Recommendations for Reducing Impacts from Methane Emissions**

Comment: Commenter (0912-Shell) states that the regulatory framework authorized under the CAA provides EPA and states with considerable latitude to establish credible and reliable protocols for determining compliance with methane intensity standards. One such option is Oil and Gas Methane Partnership 2.0 (OGMP 2.0), which establishes a greatly improved set of measurement, reporting and verification (MRV) protocols that have been under development since 2019 by the United Nations Environment Program (UNEP) and the Climate and Clean Air Coalition (CCAC) in partnership with the European Union Commission, the Environmental Defense Fund, and major industry players. The MRV protocols focus on establishing best practices for quantifying methane emissions from all segments of the oil and gas sector where material quantities of methane emissions can be released. OGMP 2.0 effectively increases the accuracy and granularity of methane emission monitoring, reporting, and verification for oil and gas assets.

In the recently proposed methane legislation, the European Union uses the OGMP 2.0 as the basis for its mandatory MRV protocols under methane regulatory program that it now has under development. The commenter (0912-Shell) believes that OGMP 2.0 sets a necessary new standard for credible and transparent methane emissions reporting, while recognizing the outstanding technological, commercial, and cost challenges to improved emissions reporting. In the current legislative proposal, these MRV protocols would likely also apply to all imports of natural gas into the European Union, including LNG and pipeline natural gas imported from other countries. Adoption of the OGMP2.0 protocols by natural gas/LNG exporters into the European Union and natural gas producers in the country of origin, satisfies MRV data transparency requirements in the European Union methane legislation.

For these reasons, the commenter (0912-Shell) urges EPA to develop robust MRV protocols for demonstrating compliance with the methane emissions standards and determining methane emission intensity across the natural gas value chain. In so doing, EPA should work to ensure that MRV protocols being developed for the U.S. regulatory program are fully consistent and generally equivalent to the version of OGMP 2.0 now being developed for use in the European Union. This equivalence will provide a simple mechanism for demonstrating that LNG from the U.S. meets the performance standards that could be established in the future for importing LNG into the European Union.

The commenter (0912-Shell) states that once control levels have been set for a subcategory based on BSER would EPA establish statewide targets that achieve an equivalent level of methane reductions based on the application of emission controls for each subcategory. One important advantage of setting statewide intensity targets is that it accounts for the great diversity of sources and operations within the oil and gas source category. Instead of just focusing on only certain specific types of sources for achieving the mandated methane reductions, the regulations would provide the most cost-effective way to achieve methane reductions by setting methane

emission intensity targets that would apply at the asset level for each company. This approach will ensure all methane sources are managed and allow companies to focus its control efforts on those sources that are most impactful and cost-effective to reduce methane emissions.

Similarly, commenter (0912-Shell) points out that there are advantages of setting one statewide intensity standard for both new and existing oil and gas sources. The combination of new and existing sources into one intensity standard provides companies with important flexibility to meet their existing source control requirements by installing new innovative control technologies and measures that can cost-effectively exceed the new source control levels mandated by NSPS OOOOa. Those surplus reductions for a company could then be used for meeting its existing source control obligations that would be established through the implementation of the state emission guidelines. According to the commenter, this approach also provides important flexibility for states, whose environmental regulatory agencies are most familiar with the unique characteristics of regional oil and gas production and the varying characteristics of producing basins.

In addition, the establishment of an intensity standard could greatly simplify the process for demonstrating the regulatory equivalence of LNG imported from the U.S. into the European Union. Commenter (0912-Shell) believes the best way to position U.S. gas exports to the European Union is based on regulatory equivalence between the trading blocks. The commenter states that this eliminates the formidable technical challenges with tracing gas molecules from individual producers along complex gas delivery chains. The commenter suggests that such a framework for demonstrating such equivalence could help to preserve U.S. competitiveness and export opportunity.

Response I-23-58: The EPA appreciates the commenter's recommendation. However, creating the recommended intensity standards and measurement, reporting and verification (MRV) protocols similar to what is required under OGMP 2.0 is not supported by CAA sections 111(b) and 111(d), which is the basis for the NSPS OOOOb standards and EG OOOOc presumptive standards. See sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

Comment: Commenter (0807-BP) supports EPA's use of CAA section 111(d) to regulate methane emissions from existing oil and natural gas sources. The commenter encourages EPA to design the 111(d) rule to promote flexibility and efficiency in compliance and drive technology innovation. The commenter suggests that one way to provide this flexibility is through a methane intensity standard. The commenter recommends that EPA consider soliciting input on the potential for incorporating methane intensity standards into its EG OOOOc rules. The commenter notes that EPA could solicit this feedback either in the context of the forthcoming supplemental regulatory proposal, or through convening a technical workshop or other forum to facilitate a dialog among experts from all sectors.

On September 20, 2021, commenter (0807-BP) submitted supplemental comments in advance of EPA issuing this proposal, which encouraged EPA to consider quantifying the "degree of emission limitation achievable" in the form of emission performance rates, and for EPA to

consider using a “methane intensity” standard.<sup>78</sup> By “methane intensity”, the commenter explains that they are referring to the volume of methane emissions from a source’s operated upstream oil and gas assets as a percentage of the total gas that goes to market from those operators.

Commenter (0807-BP) points out that states are beginning to use a methane intensity approach. For example, the commenter reports that the Colorado Air Quality Control Commission (“AQCC”) recently established a GHG intensity target for the upstream segment. 5 Colo. Code Regs. § 1001-26(IV) (2021). The AQCC defines “greenhouse gas intensity” as CO<sub>2</sub> equivalent emissions from pre-production and production as a percentage of hydrocarbon liquids and gas production. The regulation sets greenhouse gas intensity targets starting in 2025.

In order to implement a methane intensity standard, the commenter (0807-BP) recommends EPA consider gathering additional information, identifying different standards for different segments, and evaluating the impact of using methane emissions data derived from measurement, as opposed to emissions factors. EPA could solicit input or form a working group to determine how methane intensity standards may be used and best defined, specifically with regard to 111(d) emissions guidelines. The commenter suggests that EPA could identify different methane emission performance rates – with different methane intensity standards – tailored to various segments of the oil and gas industry. Additionally, EPA could evaluate how transitioning to actual methane emissions data, as opposed to data calculations using emissions factors, may change or increase the reported methane emissions from certain sources and how to factor that into what baseline year to use. In any event, the commenter recommends that EPA consider and seek stakeholder input on how best to take advantage of methane intensity standards as a regulatory tool that could be incorporated into the EGs, whether in the context of its supplemental proposal in this rulemaking or through other complementary mechanisms.

Response I-23-59: See Response I-23-58 of this Chapter.

Comment: Commenter (0602-Business Roundtable) believes the U.S. should adopt a more comprehensive, coordinated and market-based approach to reducing emissions. While a market-based climate strategy should apply broadly across the economy, the commenter expresses that no one policy or approach can fully address climate change across such a diverse economy and such diverse sources of GHG emissions. In unique circumstances, the commenter provides that nonduplicative, tailored policies may be more effective or administratively feasible. Targeted, smart methane regulation would help meaningfully address climate change and could present one such circumstance. Moreover, the commenter reports that smart methane regulation is immediately actionable, given the high cost-effectiveness of many technologies and methods for preventing, monitoring, and mitigating emissions.

Response I-23-60: The EPA appreciates the commenter’s recommendation. However, adopting a market-based approach to reducing emissions is not supported by CAA sections 111(b) and 111(d), which is the basis for the NSPS OOOOb standards and EG OOOOc presumptive standards. See sections IV (Statutory Background and Regulatory History) and V (Legal Basis

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<sup>78</sup> See Letter from Downey Magallanes, *supra* note 8, at 4.

for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

## **23.12 Clarification of What Constitutes a Reconstruction**

Comment: Commenter (0742-ADEC) requests clarification on the definition of “reconstruction”. The commenter provides that “reconstruction” is usually defined as “[t]he fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source”. The commenter adds that the term “reconstruction” is nowhere used to define changes or repairs to many of the affected facility emissions units in the proposal. A well that has been fractured becomes a modified well, and refracturing the well doesn’t change its status as a modified affected facility. The commenter inquires: (1) what constitutes a “reconstructed” well or well-site; and (2) what constitutes a “reconstructed” natural-gas operated diaphragm pump, where the low fixed capital cost would support replacement as the primary option to reconstruction. Likewise, the commenter adds that tracking the cost of repair to justify whether an individual piece of equipment was “reconstructed” is beyond the emissions value gained or economic sense realized for many of these extremely low-cost portable units. The commenter notes that the same argument can be advanced as regards a single natural gas operated pneumatic controller, as well as many other of these small emissions units that become affected facilities. The commenter explains that the low fixed-capital cost of many of these individual emissions units supports replacing the on-site unit with a pool or stock replacement that can be repaired off-line as time permits the owner or operator. Tracking pools of small, portable equipment that may change status from a non-affected facility to an affected facility simply through field repair and upgrade off-site has no emissions-reduction value and simply exposes an owner/operator to compliance risk. According to the commenter, it will be essentially impossible to monitor and track the compliance status of huge numbers of portable units that may get moved from an exploratory well-site to another without informing compliance personnel.

Response I-23-61: The EPA considered this and other comments received related to what constitutes a “reconstruction” when developing the proposed and final regulatory text for the NSPS OOOOb and EG OOOOc included under the December 2022 Supplemental Proposal.

Under 40 CFR 60.15, “Reconstruction” means the replacement of components of an existing facility to such an extent that:

- (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
- (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

For the final rule, the EPA also allows owners and operators of natural gas-driven process controllers and pumps to choose an alternative definition of what constitutes a “reconstruction” which would allow reconstruction to be defined based on the number of natural gas-driven process controllers or pumps in the affected facility. Owners and operators may choose which

definition of reconstruction to apply and whether to comply; they do not need to apply both. If owners and operators choose to comply with the latter option, they may demonstrate compliance with 40 CFR 60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven process controllers in the affected facility is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of controllers” or “number of pumps”, they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in 40 CFR 60.15(b)(1).

Additionally, the final rule defines “reconstruction” of a tank battery when any of the following occurs and result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in the rule. (1) At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or (2) the provisions of 40 CFR 60.15 are met for the existing tank battery that consists of a single storage vessel.

### **23.13 Other General Requests for Clarification/Requests/Comments**

Comment: Commenter (0946-MOGA) recommends EPA provide clear, well-defined, and easily understood proposed regulations that can be understood by small businesses. This would include clear definitions of major equipment, calculation methodologies with samples, well-defined source definitions aligned with the 1979 CAA and clarification of exemptions.

Response I-23-62: The EPA considered this and other comments received when developing the proposed regulatory text for the NSPS OOOOb and EG OOOOc included under the December 2022 Supplemental Proposal. Based on comments received on the December 2022 Supplemental Proposal rule language and requirements, the EPA made further changes to the rule to improve clarity. Please also see section X of the final rule preamble for a summary of EPA’s final NSPS OOOOb standards and EG OOOOc presumptive standards.

Comment: Commenter (0539-AOGCC) states that having different requirements for the North Slope and Cook Inlet could make compliance by the operators that work in both regions more complicated.

Response I-23-63: Where the EPA has finalized different requirements for the North Slope and the Cook Inlet, it is because commenters have provided information to support differences in technologies and conditions on the Alaska North Slope. For example, under the NSPS OOOOb and EG OOOOc, owners or operators of wet seal centrifugal compressors on the Alaska North Slope that are equipped with a seal oil recovery system (*i.e.*, centrifugal compressors equipped with sour seal oil separator and capture system, such as a seal oil gas separation system that separates gas from the sour seal oil exiting the compressor seal assembly, upstream from the degassing drum) have the option to comply with the rule by meeting a performance-based volumetric flow rate at or below 9 scfm (in operating or standby pressurized mode) per seal. In lieu of complying with this alternative compliance option, an owner or operator can comply by meeting the requirements for other compressors with wet seals (including those located on the Cook Inlet). Please also see section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the final rule preamble.

## 23.14 Enforcement

Comment: Commenter (0592-Citizens United for Responsible Energy) states that enforcement of the rules is the only way to assure that reductions to emissions actually occur. In this case, the commenter suggests that producers must have an expectation that they will be held accountable for loss of resources by excess emissions. According to the commenter, fines will not be enough, and shutdowns may be necessary in order to protect our air and planet. The commenter recommends that EPA's Self-Audit program should be stringently examined and re-assessed in this regard.

Commenter (0941-350 Silicon Valley) further suggests that penalties, proportional to the environmental damage inflicted by failure to comply with performance standards rules, must be a tool available to EPA. The commenter contends that no company should benefit economically by not complying with methane emissions standards. Failure to replace damaged components, failure to inspect equipment and make necessary repairs, failure to use flare stacks as intended, failure to demonstrate that flaring was necessary for emergency purposes and failure to report venting and flaring episodes, especially routine flaring, are some examples of incidents that should be subject to penalties once new rules and target dates become enforceable. The commenter adds that the supplemental methane emissions rule includes descriptions of penalties to be imposed on companies that fail to implement required performance standards.

Response I-23-64: Violations of the final rules may be subject to civil enforcement under Section 113 of the Clean Air Act, 42 U.S.C. § 7413. Under Section 113, EPA may pursue administrative or civil enforcement actions to restrain violations, order compliance, and assess or seek the assessment of penalties consistent with the statutory penalty limits, as modified by the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, the Debt Collection Improvement Act of 1996, 31 U.S.C. § 3701, and most recently by the Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Pub. L. No. 114-74 § 701, 129 Stat. 584, 599-601. In determining the amount of penalty in an administrative or judicial civil enforcement matter, EPA or a court may consider factors set forth in Clean Air Act ~~ion~~ section 113(e), 42 U.S.C. § 7413(e), including the economic benefit of noncompliance.

Knowing violations of the final rules may also be subject to criminal enforcement under Section 113(c) of the Clean Air Act, 42 U.S.C. § 7413(c). In addition, regarding reporting and monitoring required by the rule, knowing false statements, material omissions, failure to report, and/or tampering with monitoring devices or methods can also be prosecuted under Section 113(c). Upon conviction, a criminal violation may result in a fine pursuant to title 18 or imprisonment, or both.

EPA has not proposed and is not finalizing separate civil or criminal enforcement or penalty provisions applicable to the methane emission standards. EPA's Audit Policy is beyond the scope of this rulemaking.

## 23.15 Administrative Record

Comment: Commenter (0761-Exelon) suggests that all contents of regulatory Docket ID No. EPA-HQ-OAR-2021-0295 should be part of the record for Docket ID No. EPA-HQ-OAR-2021-0317. The commenter states that EPA opened a docket for stakeholders to submit early input on issues informing the Proposal, and that docket was assigned Docket ID No. EPA-HQ-OAR-2021-0295. According to the Proposal, the contents of Docket ID No. EPA-HQ-OAR-2021-0295 are not automatically part of the Proposal rulemaking record, and in order for information submitted to that docket to be considered in the Proposal rulemaking, it must be resubmitted to Docket ID No. EPA-HQ-OAR-2021-0317. According to the commenter, that approach risks excluding information and material that informed EPA's Proposal from the administrative record. Instead, the commenter requests that all contents of Docket ID No. EPA-HQ-OAR-2021-0295 be automatically incorporated into and considered part of the rulemaking docket for this Proposal, Docket ID No. EPA-HQ-OAR-2021-0317.

Response I-22-65: See Response I-23-22 of this Chapter.

## 23.16 One-Size Fits All Approach

Comment: Commenter (0740-Utah Petroleum Association) supports the appropriate regulation of methane and VOC emissions. Yet Utah's oil and gas operations have several unique aspects that EPA must consider in proposing rule language and finalizing the new source performance standards (NSPS) OOOOb and EG OOOOc regulations. Most notably, they report that their operations on Tribal lands and within an ozone nonattainment area, their unique waxy crude oils, their remote operations that do not lend themselves easily or within reasonable cost to electrification, their labor shortage more acute than elsewhere in the country, and their small operators all require consideration in the final rulemaking. These considerations will help to ensure promulgation of a practical and cost-effective rule for all and that will not drive small operators out of business.

Response I-23-66: The EPA, when developing the final NSPS OOOOb and EG OOOOc requirements, considered these and other comments that expressed concern that the uniqueness of their oil and natural gas operations be considered. The revised Initial Regulatory Flexibility Analysis (IRFA) and Final Regulatory Flexibility Analysis (FRFA) provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on businesses. In addition to providing several compliance alternatives for affected facilities under NSPS OOOOb and designated facilities under EG OOOOc, the EPA has also considered issues such as lingering supply chain issues and increased demand for equipment and services when establishing compliance, and repair and delay of repair provisions included in the final NSPS OOOOb and EG OOOOc rules to account for parts not being available.<sup>79</sup>

Additionally, both NSPS OOOOb and EG OOOOc include provisions that could be pursued for an alternative but equivalent compliance option under NSPS OOOOb or equivalent or less

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<sup>79</sup> See sections XI.A.1.e (Delay of repair due to parts unavailability) of the final rule preamble for example.



stringent requirements considering remaining useful life and other factors (RULOF) under EG OOOOc under a state plan. 40 CFR 60.5399b (What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?) of NSPS OOOOb provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. See section XIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for state plan requirements and sub-section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Comment: Commenter (0732-Panhandle Producers and Royalty Owners Association/Remnant Energy) supports the presumed objective of these rules, but it would be their recommendation to set objectives and allow the industry to innovate to meet these objectives of emission reduction. Production methods vary greatly as required by various reservoirs. A natural gas stream that is high in water vapor has different issues than a natural gas liquid (NGL) rich gas stream. One size fits all solutions will prove counterproductive and defeat the improvements that all desire.

Response I-23-67: These final actions stem from the EPA's authority and obligation under CAA section 111 to directly regulate categories of new stationary sources that cause or contribute to endangerment from air pollution and to promulgate EG for states to follow in regulating existing sources (designated facilities) in the source category. See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

See also Response I-23-66 of this Chapter.

Comment: Commenter (0793-PBPA) states that in both the NSPS and the EG, EPA has applied a one-size fits all approach to the regulation of an incredibly diverse industry. The commenter asserts that the regulations applied in the Marcellus Shale may not be appropriate for the Haynesville Shale and what works in the Bakken may not work in the Permian Basin. There are even intra-basin differences. For example, the commenter explains that within the upstream segment of the Permian Basin, the Midland Basin varies significantly from the Eastern Shelf, which varies significantly from the Central Basin Platform. Sub-basin variations are also material. The Midland Basin Trend Area fields are quite different than Grayburg fields.

Commenter (0793-PBPA) points out that similarly, the emissions for a site producing 10,000 barrels a day are not the same as a stripper well site producing 10 barrels a day; and yet EPA's one-size-fits-all approach would effectively treat them the same. In fact, in some instances, the required emission controls for low producing sources actually generate more emissions than the regulated facility itself. The proposal also does not recognize that many upstream and midstream

sources are spread out over a wide geographic area, located in remote regions, and do not have dedicated onsite staff.

Commenter (0793-PBPA) states that with regard to EPA's proposed repair requirements, for example, operators of such facilities must coordinate the delivery of new equipment, the arrival of repair contractors, and then for a separate contractor to come and perform the resurvey. Simply put, the commenter recommends that EPA develop a more nuanced approach that considers the location, basin, reservoir, remaining useful life (including of reserves), product, throughput, and age of a particular facility (among other things) before mandating a set of performance standards.

Response I-23-68: See Response I-23-66 of this Chapter.

Comment: Commenter (0946-MOGA) questions EPA's justification of proposing new regulations and capital investments to reduce emissions every 2 or 4 years? How can EPA justify new regulations without a baseline to determine whether previous rules 40 CFR Part 60, Subpart OOOO and the current rule 40 CFR Part 60, Subpart OOOOa have been successful?

Commenter (0946-MOGA) argues that existing regulations for new wells including NSPS OOOO and OOOOa combined with natural production depletion (or Production Decline) will facilitate EPA's emission reduction goals. The commenter evaluated three Michigan Basin producers reported 40 CFR Part 98, Subpart W annual reported Carbon Dioxide ("CO<sub>2</sub>"), Methane ("CH<sub>4</sub>") and Nitric Oxide ("NO<sub>x</sub>") emission over the 9-year required reporting period from 2011 through 2020. The commenter attached a table that shows the initial 2011 reported data, the 2020 reported data and the percent change over 9 years.

From the data provided in the attached table, commenter (0946-MOGA) observed an average annual CO<sub>2</sub> reduction of 5.0%, an average annual methane reduction of 7.1% and an average annual NO<sub>x</sub> reduction of 6.19% for the three companies, in aggregate. Further, the commenter observed a total CO<sub>2</sub> emission reduction of 45.03%, a total CH<sub>4</sub> emission reduction of 64.59% emission reduction and a total NO<sub>x</sub> emission reduction of 55.70%, to date. The above stated emission reductions will likely continue on the current annual rate of decline as more facilities have modifications and become subject to the existing NSPS OOOOa regulations.

Given the above data, the commenter (0946-MOGA) believes EPA must justify the current proposed regulations by explaining why the current NSPS OOOOa regulations are not sufficient to meet emission reduction goals. At minimum, MOGA believes EPA must justify a "one-size-fits-all" approach to emission reductions when many producers are currently employing effective techniques and technologies from previous rulemaking efforts.

Response I-23-69: See Responses I-23-14, I-23-66 and I-23-67 of this Chapter.

## **23.17 Out of Scope Comments**

### ***23.17.1 Memorandum of Understanding***

Comment: Commenter (0792-IOGCC) provides a forum for states and EPA to work together to address issues of mutual concern. This year marks the twentieth anniversary of the establishment of a Memorandum of Understanding (MOU) between EPA and the commenter regarding communication and cooperation related to environment regulation of oil and natural gas exploration and production activities. EPA and the commenter have reviewed and renewed this MOU every few years, most recently in 2019. The MOU and the Task Force it creates have provided an effective forum for the exchange of information and ideas on oil and gas regulation.

Before publishing the referenced proposal late last year, the commenter (0792-IOGCC) states that EPA did not avail itself of the mechanisms for communication and cooperation established in the MOU. Under the MOU, the EPA Administrator designates the EPA Co-Chair of the Task Force and up to five additional members. Because the EPA Co-Chair and other EPA members have not yet been designated in the new administration, the Task Force did not meet in 2021 in accordance with the MOU. The commenter state that they expected and understood the change in administration might produce a brief delay in the scheduling of Task Force meetings. Now that a full year has passed, however, the EPA members should be appointed immediately, especially as EPA is moving forward with significant proposals within the scope of the MOU. The commenter suggests that the November 2021 proposal is a prime example of the kind of issue the MOU Task Force should address. The add that the proposal would have benefited from the communication and coordination that has traditionally occurred when EPA and the commenter work together in accordance with the MOU.

Response I-23-70: This comment on the referenced MOU is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.2 NEPA and CAA Section 309***

Comment: Commenter (0781-NTAA) believes that, as stated in the Agency's draft strategic plan, EPA should use its review authority under NEPA and CAA section 309 to actively review new oil and natural gas leasing particularly in Indian country. The commenter believes that EPA should use this authority to help coordinate and facilitate proper evaluation of new oil and natural gas production, particularly in Indian country. The commenter suggests that EPA work with other federal agencies to fully evaluate the climate impacts of proposed oil and natural gas actions, including by considering the costs with the use of the social cost of methane.

Response I-23-71: This comment on NEPA and CAA section 309 is outside the scope of this rulemaking; as such, no response is required.

Comment: Commenter (0438-Private Citizen) has reviewed NEPA and feels that FERC has full authority on how FERC executes the Natural Gas Act. It also appears that FERC is meant to use NEPA as a basis of the review with states. According to the commenter, this would suggest that FERC can make policy and regulations taking into consideration NEPA, which is broad and

where natural gas expansion has already undermined many of NEPA's stated provisions (highlighted in an appendix to their comment letter).

Response I-23-72: This comment on NEPA is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.3 U.S. Securities and Exchange Commission (SEC) and Greenhouse Gas Reporting Program (GHGRP) Regulations***

Comment: Commenter (0588-Project Canary) states the U.S. Securities and Exchange Commission (SEC) is planning to propose several regulations and other administrative actions relating to environmental, social, and governance (ESG) factors and climate risk disclosure, in a parallel track to EPA's development of this rule. These actions will significantly impact the oil and natural gas sector – and those interested in investing in that sector. Regulations the SEC is considering over the next six months, include but are not limited to: mandatory climate change disclosures; shareholder proposals in proxy statements; rules relating to investment companies and investment advisors to address matters relating to ESG; and climate stress testing for large asset managers and large investment companies.

The commenter (0588-Project Canary) states one of the main issues relates to the U.S GHGRP that is run by EPA. The onshore oil and natural gas sector is required to submit information under subpart W of 40 CFR part 98 for the GHGRP. Both environmental groups and the oil and natural gas industry do not believe that subpart W accurately captures the emissions from the oil and natural gas sector – whether it be underreported or overreported. The commenter explains that part of the reason for issues with capturing accurate data comes from subpart W using over 100 emissions factors for determining how much is emitted from the oil and natural gas sector. The commenter states that continuous monitoring can help eliminate the need for the use of emission factors as it can provide real information on emissions. This will also help bridge the gap on what a company may report to the SEC under its forthcoming regulations and what is being provided under the EPA GHGRP.

The commenter (0588-Project Canary) notes it is key that the SEC and EPA communicate to avoid unnecessary reporting burden or duplicative or conflicting requirements. Luckily, continuous monitoring can help bridge the gap between the two regulations by providing a compliance alternative for EPA, while also serving as a mechanism to allow for compliance with SEC's upcoming regulations. Continuous monitoring provides a way to ensure that companies are providing the reductions that they are claiming on their SEC filings with respect to climate change.

Response I-23-73: The comments on the GHGRP are outside the scope of this rulemaking, as such, no response is required. The EPA finalized the NSPS OOOOb and EG OOOOc rules with consideration of minimizing or eliminating duplicative reporting with what is required under the GHGRP. As an example, the EPA specifically does not require owners or operators conducting liquids unloading at their gas well affected facilities to estimate, record and report estimates of vented emissions during events because this information is already being reported under the

GHGRP. See section X of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc requirements.

With regards to the EPA and SEC communicating to avoid unnecessary reporting burden or duplicative or conflicting requirements, the SEC oversees securities exchanges, securities brokers and dealers, investment advisors, and mutual funds in an effort to promote fair dealing, the disclosure of important market information, and to prevent fraud. It is unlikely that the information EPA requires to demonstrate compliance with an EPA rule developed under the CAA would overlap to any significant degree with what would be required by the SEC.

#### ***23.17.4 Ethane Cracker Plant***

Comment: Commenter (1322-Lone Star-Sierra Club) provides an example where the largest ethane cracker plant in the world (a facility that turns methane into the precursor for single-use plastic bags) is almost completed on Corpus Christi Bay. The infrastructure has required many, many miles of gas pipeline. The commenter reports that when the factory applied for a TCEQ permit to release VOCs, the TCEQ itself looked at the numbers, and said they were too high and suggested instead that the company build two plants right next to each other, which would allow each facility to release half of the original requested amounts. The commenter notes that this plant is surrounded by a minority community. At a TCEQ meeting the commenter attended, they stated that community members requested that the company put benzene (a known carcinogen VOC) monitors around the perimeter of the facility. The commenter reports that the company responded by saying, “You do not require any other Texas facility to do that.” According to the commenter, this is despite the fact that the company operates another such facility in New Jersey, where they have benzene monitors around the plant. The commenter reports that they were not required to put up any benzene monitors.

Response I-23-74: This comment on air emissions monitoring at ethane cracker plants is outside the scope of this rulemaking; as such, no response is required.

#### ***23.17.5 Radioactive Substances***

Comment: Commenter (1388-Public Citizen) does not find radioactive substances listed as pollutants carried in the natural gas stream in EPA’s proposed rule. Naturally occurring radioactive substances are found deep in the earth, including areas of shale where hydraulic fracturing (fracking) is used to extract natural gas. Fracking extracts and concentrates these substances. They are brought from deep underground, where they are safe, to the surface, where they are dangerous to the public health and the environment. Under a 1980’s federal exemption to the Resource Conservation and Recovery Act (RCRA), streams of waste from oil and gas wells, including radioactive waste, are not required to be handled as hazardous wastes. Radioactive substances cannot not be fully separated from the gas stream, and they are carried downstream through gas transmission pipelines, and compressor stations.

Commenter (1388-Public Citizen) states that due to significant volumes of leakage, and intentional releases from these pipelines, and compressor stations, persons, wildlife, and the environment in proximity to them are at risk for radiation contamination. Radioactive radon-222

is carried in the natural gas stream. A compilation of studies indicated an average concentration of 40 - 60 pico-curies per liter in natural gas transmission lines. This is 100 to 150 times higher than ambient air levels, which are 0.4 pico-curies per liter. They are also much higher than the 4 pico-curie per liter threshold for homes, where EPA advises that remedial action must be taken to reduce the health risk.

Commenter (1388-Public Citizen) points out that EPA has determined that radon-222 causes 21,000 lung cancer deaths per year in our country. Many locations near compressor stations are already high in naturally occurring radioactive radon-222. Leaks and intentional discharges from compressor stations could further increase the risk of radon contamination for citizens along the routes. Radioactive scales and sludges containing radioactive lead-210 and radioactive polonium-210, which are decomposition products of radon-222, are also deposited as scales along the inside of the pipes, and in filtering materials at compressor stations, and other structures.

Commenter (1388-Public Citizen) states that studies conducted by the Louisiana Department of Environmental quality, the Pennsylvania Departments of Environmental Protection, and the Oil and Gas Journal found an average of over 40,000 pico-curies per gram in these scales. Lead-210 is also present inside the pipes as particulate matter in dust, or black powder, which can also be released through leaks and intentional discharges. Filtering devices in the pipes and compressor stations cannot filter all of the particulate matter, and it is likely that lead-210, and possibly polonium-210 are discharged from compressor stations and along natural gas transmission lines through leaks, venting, blowdowns, and compressor station combustion discharges.

The threat to public health, wildlife, and the environment from these radioactive substances has not been adequately studied, regulated, or mitigated. These threats are significant. They must be fully taken-into-account, and mitigated in order to protect the public health, and the environment.

Commenter (1388-Public Citizen) suggests that EPA should include comments in the proposed rule that consider the public health and environmental threat from these radioactive substances. EPA should also act to eliminate this threat.

Response I-23-75: This comment on threats from radioactive substances from the oil and natural gas industry is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.6 AERMOD Modeling***

Comment: Commenter (1388-Private Citizen) finds that the proposed rule does not go far enough in reducing methane and pollutant emissions from the oil and gas industry. The commenter would like to see more stringent controls resulting in far less emissions, and with those emissions being completely prohibited in the very near future. The commenter suggests that AERMOD should not be used for compressor station air pollution air modeling because AERMOD models may not accurately predict pollutant deposition, distribution, or concentration from variable state discharges from compressor stations.

According to the commenter (1388-Private Citizen), most of the pollutants from compressor stations are heavier than air, and much heavier than methane pollutants in the combustion exhaust emissions, in the blowdown emissions, and in leaks from compressor stations, and may drop out of the discharge plumes, and be deposited in, and accumulate near the compressor station. The commenter adds that pollutants may also react with each other, and form solid particulate matter which may drop out of the plume. The commenter states that the entire pollutant discharge plume may also come into contact with the ground near the compressor station during certain weather conditions, including air inversions.

Commenter (1388-Private Citizen) states that AERMOD is what is referred to as a Gaussian model. There are a number of scientific articles that indicate that AERMOD modeling systems are not suitable to predict pollutant concentration, deposition, or distribution from compressor stations.<sup>80</sup>

Commenter (1388-Private Citizen) shows that section 2.1 (i) of Appendix W to Part 51—Guideline on Air Quality Models, states Gaussian plume models use a steady-state approximation, which assumes that over the model time step, the emissions, meteorology and other model inputs, are constant throughout the model domain, resulting in a resolved plume with the emissions distributed throughout the plume according to a Gaussian distribution. This formulation allows Gaussian models to estimate near-field impacts of a limited number of sources at a relatively high resolution, with temporal scales of an hour and spatial scales of meters. However, this formulation allows for only relatively inert pollutants, with very limited considerations of transformation and removal (*e.g.*, deposition), and further limits the domain for which the model may be used. Thus, Gaussian models may not be appropriate if model inputs are changing sharply over the model time step or within the desired model domain, or if more advanced considerations of chemistry are needed.

Commenter (1388-Private Citizen) explains that emissions from compressor stations would not be steady state emissions. The commenter adds that they would vary widely over time. The commenter notes that they would vary during startup and shut down procedures, during variable air temperatures, during venting and blow down, during variable turbine use, during variable combustion load scenarios, and as the quantity of natural gas passing through the station varies, including the amount that is leaking from the facility.

Commenter (1388-Private Citizen) suggests that deposition of pollutants near the facility is a significant concern from compressor station emissions. The commenter reports that most of the pollutants carried in the gas stream, that would be discharged during blowdowns, venting, and leaks, and in combustion emission discharges are heavier than air, and much heavier than the methane in which they are initially entrained. They may deposit out of the emission plume near the compressor station due to their significantly higher molecular weight.

Commenter (1388-Private Citizen) also suggests that chemical reactions in the discharge plumes could also result in gaseous substances like sulfur dioxide and nitrous oxides reacting, and being

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<sup>80</sup> In Volume 82, Number 10 of the Federal Register, dated January 17, 2017, under 40 CFR Part 51 EPA issued a final rule revising guidelines on air quality models. (EPA-HQ-OAR-2015-0310; FRL-9956-23-OAR) RIN 2060-AS54.

reduced to solid, particulate matter that would also tend to drop out of the plume. AERMOD does not account for this change in the discharge plume. The commenter states that AERMOD only allows for inert, non-reactive plume components in the air dispersion analysis.

Commenter (1388-Private Citizen) suggests that air modeling for natural gas compressor stations be completed using a model that accurately predicts the deposition, distribution, and concentration of pollutants discharged during variable discharges scenarios, and under all weather conditions. The commenter believes there may be other air models that would be more accurate than an AERMOD model.

Response I-23-76: This comment is about AERMOD modeling and why it should not be used for air modeling for natural gas compressor stations and is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.7 Clean Water Act (CWA) or Safe Drinking Water Act (SDWA)***

Comment: Commenter (0414-Waterspirit) states that natural gas drilling's process as it is done today uses not only copious amounts of fresh water but also undisclosed toxic chemicals which have never been subject to the CWA or SDWA, per the Halliburton loophole<sup>81</sup>.

Response I-23-77: This comment regarding the CWA or SDWA is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.8 Toxic Substances Control Act (TSCA)***

Comment: Commenter (0746-Methane Action) recommends that EPA, in the final rule or your next proposal, incorporate and use the tools EPA has been given in the Toxic Substances Control Act (TSCA), as amended only a few years ago, to determine the extent to which methane presents not only the hazards that warrant its removal under TSCA, and not only a clear and present danger, but on-going harm that TSCA requires the EPA to in turn require the emitters to reduce, remove and/or retrieve. The commenter states that, as Inside Climate News put it, in their story entitled, "Gas Stoves in the US Emit Methane Equivalent to the Greenhouse Gas Emissions of Half a Million Cars":

Cooking with gas is heating up the climate and filling some homes with hazardous nitrogen oxides in excess of EPA safety standards for outdoor air concentrations. The study found that:

Running gas ovens and stove top burners in small kitchens with poor ventilation resulted in emissions that within a few minutes surpassed the Environmental Protection Agency's safety standards for outdoor air concentrations of nitrogen dioxide, an irritant that can aggravate asthma and may contribute to the development of the disease. The agency does not have a separate safety standard for indoor air concentrations of nitrogen dioxide.

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<sup>81</sup> <https://www.statnews.com/2021/04/26/end-fracking-exemptions-a-threat-to-maternal-and-public-health/>.



Meanwhile, the commenter (0746-Methane Action) reports that an EPA-funded study<sup>82</sup> by the Harvard Chan School of Public Health, reveals the people over 65 who live within a kilometer of a fracking or directional drilling site have a higher rate of death than those who do not. As Harvard put it: "Living near or downwind of unconventional oil and gas development linked with increased risk of early death."<sup>83</sup> According to the commenter, the presumption of toxicity, hazard and on-going harm to health is established and warrants EPA's invocation of TSCA.

Response I-23-78: This comment regarding TSCA is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.9 National Emission Standards for Hazardous Air Pollutants (NESHAP)***

Comment: Commenter (0809-Earthjustice) recommends the critical importance that EPA does not ignore communities exposed to toxic air pollution. The commenter provides that there are 57 million people living within 50 kilometers of oil and gas facilities, according to EPA data.<sup>84</sup> Residents of rural communities like Eagle Ford, Texas, and of urban neighborhoods such as Wilmington in the city of Los Angeles, are surrounded by oil production operations and oil refineries operating near their homes, public schools, and recreational parks.<sup>85</sup> Overburdened by pollution, the commenter states that individuals in these and other communities have for years complained of trouble breathing, neurological problems, and concerns about increased risk for other health threats. The commenter asserts that EPA must act now to protect these communities, as it is required to do under section 112 of the CAA. See 42 U.S.C. § 7412(d), (f)(2).

Commenter (0809-Earthjustice) points out that the oil and gas sector emits thousands of tons of harmful compounds each year, including organic HAPs such as benzene.<sup>86</sup> Benzene is a known human carcinogen that EPA has identified as a major contributor to cancer risk nationwide in the most recent National Air Toxics Assessment (NATA).<sup>87</sup> The commenter notes that EPA's 2011 draft residual risk assessment showed that individuals living in close proximity to oil and gas sources endure substantial cancer, chronic non-cancer, and acute health threats from being exposed daily to emissions from nearby oil and gas facilities.

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<sup>82</sup> <https://www.hsph.harvard.edu/news/press-releases/living-near-or-downwind-of-unconventional-oil-and-gas-development-linked-with-increased-risk-of-early-death/>.

<sup>83</sup> Ibid.

<sup>84</sup> EPA, Draft Residual Risk Assessment for the Oil and Gas Production and Natural Gas Transmission and Storage Source Categories 34-35 tbl. 4.2-1 (July 2011), <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-0032>.

<sup>85</sup> See, e.g., Jim Morris et al., Big Oil, Bad Air: Fracking the Eagle Ford Shale of South Texas, Ctr. For Pub. Integrity (Feb. 18, 2014), <https://eagleford.publicintegrity.org/>; Alexandria Herr & Clayton Aldern, California's Dirty Little Secret: Oil Wells in the Backyard, Grist (Oct. 13, 2021), <https://grist.org/project/accountability/wilmington-california-oil-gas-setbacks/>.

<sup>86</sup> See, e.g., NRDC, Drilling in California: Who's at risk?, at 6 (Oct. 2014), <https://www.nrdc.org/sites/default/files/california-fracking-risks-report.pdf>; Ctr. for Biological Diversity, Danger Next Door: The Top 12 Air Toxics Used for Neighborhood Oil Drilling in California (Dec. 2017), available at <https://www.biologicaldiversity.org/publications/papers/DangerNextDoor.pdf>.

<sup>87</sup> 2014 NATA Summary of Results, at 4, [https://www.epa.gov/sites/default/files/2020-07/documents/nata\\_2014\\_summary\\_of\\_results.pdf](https://www.epa.gov/sites/default/files/2020-07/documents/nata_2014_summary_of_results.pdf).

Commenter (0809-Earthjustice) states that in the regulatory impact analysis for the NSPS proposal, EPA estimates, based on 2017 NEI data, that approximately 6.8 million people have a cancer risk of more than one-in-one-million, more than 142,000 people have a cancer risk of equal to or more than 50-in-one-million, and more than 38,000 people have a cancer risk of equal to or more than 100-in-one-million.<sup>88</sup> While these risk levels only reflect cancer risk and no other chronic and acute health risks, these risk levels are unacceptable and cannot be fully addressed under the NSPS alone. First, EPA admits that a “majority of the estimated risk is likely being driven by sources not impacted by this proposed regulation.”<sup>89</sup> Second, while continuing revision of the NSPS standards under section 111 is important and necessary, the section 112 requirements most directly address human health risk due to emissions of air toxics. NESHAP rulemaking is therefore necessary to mitigate both cancer risk “driven by sources not impacted by” the NSPS proposal, as well as the unaddressed non-cancer risk associated with inhalation of hazardous air pollutants.

Commenter (0809-Earthjustice) points out that EPA’s last revision of the NESHAP for the oil and gas sector was in 2012.<sup>90</sup> It has not completed any review or revision since then, even though several groups—including undersigned organizations—filed a petition seeking EPA’s reconsideration of the 2012 standards.<sup>91</sup> The commenter complains that the reconsideration petition has been pending over nine years, a length of delay so long that a subsequent eight-year review deadline under section 112(d)(6) has come and gone. See 42 U.S.C. § 7412(d)(6). The commenter contends that EPA’s inaction has left in place illegal and arbitrary standards that fail to regulate or that insufficiently regulate hazardous air pollution from oil and gas sources.

Response I-23-79: This comment regarding the NESHAP is outside the scope of this rulemaking; as such, no response is required.

Comment: Commenter (0809-Earthjustice) urges EPA to complement this important work on methane and VOC emissions from the oil and gas sector with a renewed focus on controlling the sector’s air toxics emissions via revised NESHAP.

Namely, the commenter (0809-Earthjustice) urges EPA to act on the outstanding reconsideration petition regarding the 2012 NESHAP rule for the oil and gas sector, as well as the now overdue duty under section 112(d)(6) to review and, if necessary, revise those standards. While EPA’s proposed updates to the NSPS proposal are a needed key step forward, the commenter asserts

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<sup>88</sup> EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review 4-30 tbl. 4-7 (Oct. 2021) [hereinafter RIA], [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsp-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsp-eg-climate-review_0.pdf).

<sup>89</sup> See *id.* at 4-28, 4-29.

<sup>90</sup> Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

<sup>91</sup> Petition for Reconsideration of Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 Fed. Reg. 49,490 (Aug. 16, 2012), 40 CFR Part 63, Subparts HH and HHH, submitted by Earthjustice on behalf of California Communities Against Toxics, California Safe Schools, Clean Air Council, Coalition For A Safe Environment, Desert Citizens Against Pollution, Natural Resources Defense Council, and Sierra Club (Oct. 15, 2012) [hereinafter Reconsideration Petition], <https://www.regulations.gov/comment/EPA-HQOAR-2010-0505-4591>.

that EPA cannot adequately protect human health and the environment from the oil and gas industry's air toxics emissions without also updating the oil and gas NESHAP.

Commenter (0809-Earthjustice) states that in addition to this ongoing exposure, unreasonable delay in reconsideration, and missed deadline—which are reasons enough for EPA to act—the 2012 NESHAP rule contains a number of unlawful components that EPA has a clear duty to fix under intervening caselaw. These include, for example, an affirmative defense to civil penalties for malfunctions that the D.C. Circuit held to be illegal in 2014 and missing emission standards for certain pollutants known to be emitted by industry sources, which the D.C. Circuit held to be also illegal in 2020.<sup>92</sup> According to the commenter, EPA has improperly left these illegal loopholes in place, causing harm that should never have occurred or been extended this long.

Commenter (0809-Earthjustice) states that EPA's now-overdue section 112(d)(6) duty requires the agency to “review and revise as necessary” the emission standards for this source category, which includes making all changes that are “necessary” to bring standards into full compliance with the CAA, such as setting limits on all uncontrolled hazardous air pollutant emissions.<sup>93</sup> To satisfy this provision, the commenter asserts that EPA must review the NESHAP to assure it sets limits on all currently uncontrolled HAP emissions from the oil and gas source categories. As promulgated in the 2012 NESHAP rule, the standards allow uncontrolled emissions of from certain emission points—for example, glycol dehydrators, storage vessels without the potential for flash emissions (“PFE”), storage vessels in the transmission and storage sector, pigging, and equipment leaks—an issue commenters raised in the 2012 reconsideration process that remains uncompleted.<sup>94</sup> Under section 112(d)(6) and LEAN, the commenter contends that EPA must set emission limits that satisfy section 112(d)(2)-(3) in the overdue rulemaking.

Commenter (0809-Earthjustice) argues that additional measures to ensure proper performance of flares is an issue of critical importance with respect to the oil and gas NESHAP, especially due to the large amount of HAPs, VOCs, and other pollutants that flares can release- and to which nearby communities are exposed, such as the Wilmington neighborhood of Los Angeles-when flares are improperly operated and insufficiently monitored. The commenter adds that prompt EPA action is needed on NESHAP Rulemaking. The commenter asserts that oil and gas NESHAP categories incorporate by reference EPA's general flare standards under 40 C.F.R. § 63.11, which themselves are decades overdue for review. The commenter notes that on multiple occasions, EPA itself has stated that the general flare standards under 40 C.F.R. § 63.11 are outdated, lead to the operation of flares with poor destruction efficiency, and require revision.<sup>95</sup>

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<sup>92</sup> See *Natural Res. Def. Council v. EPA*, 749 F.3d 1055, 1062-64 (D.C. Cir. 2014); *Louisiana Envtl. Action Network v. EPA (LEAN)*, 955 F.3d 1088, 1096 (D.C. Cir. 2020).

<sup>93</sup> See 42 U.S.C. § 7412(d)(2)-(3), (6); LEAN, 955 F.3d at 1096.

<sup>94</sup> See Reconsideration Petition, *supra*, at 7-25, app. tbl. 1.

<sup>95</sup> EPA published two documents in 2012 that acknowledged the shortcomings of the general flare standards. First, EPA published an Enforcement Alert regarding flaring violations, in which the agency recognized that certain needed parameters affecting the efficiency of flares are not captured within current standards, including maintaining the appropriate steam-to-vent-gas ratio and ensuring that the heating value of combustion zone gas is high enough to maximize combustion efficiency, neither of which are included in the General Flare Requirements. See EPA, EPA Enforcement Targets Flaring Efficiency Violations, Enforcement Alert (Aug. 2012), <https://www.epa.gov/sit> This

The commenter recommends that EPA revise the NESHAP to include strengthened flare standards for the oil and gas NESHAP categories. In doing so, the commenter states EPA should follow recent NESHAP rulemakings for chemical and petrochemical source categories, which set out improved flare operational and monitoring requirements (though without adding the unlawful exemptions EPA added in some of these rules).<sup>96</sup>

Commenter (0809-Earthjustice) asserts that without decisive action on air toxics standards, EPA will fail to fulfill its duties under the CAA to protect human health and the environment from air pollution caused by the oil and gas industry. Accordingly, the commenter urges EPA to ensure the aforementioned issues reach full and prompt resolution with all due speed through a full and comprehensive use of EPA's section 111 (NSPS) and section 112 (NESHAP) authorities, rather than continuing to delay its NESHAP duties indefinitely. In requesting such a comprehensive strategy, the commenter does not suggest that the agency should delay development of the agency's final NSPS rule—or, for that matter, further delay action on the NESHAP—but rather the agency should enhance its existing analysis and data collection process in furtherance of the NESHAP reconsideration and review as well.

Specifically, commenter (0809-Earthjustice) suggests EPA look carefully at how the two sets of standards address oil and gas industry sources, pollutants, local health risks, cumulative impacts assessment, and potential and known industrial and natural disaster risks in order to identify and eliminate any gaps in coverage. According to the commenter, of particular importance is the need for EPA to anticipate the information it requires for the NESHAP rulemaking, identify all known information deficits, and promptly begin a targeted ICR process as soon as possible.

Commenter (0809-Earthjustice) provides the example that EPA opted not to promulgate standards for storage vessels without potential flash emissions (PFE) on the basis that it did not have adequate data to do so.<sup>97</sup> This was a clear violation of the agency's duty to collect

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comment regarding the NESHAP is outside the scope of this rulemaking; as such, no response is required. [es/production/files/documents/flaringviolations.pdf](https://www.epa.gov/production/files/documents/flaringviolations.pdf).

Second, following on the uniform emission standards rulemaking, EPA published a report in April 2012 entitled “Parameters for Properly Designed and Operated Flares”, which noted that reliance on the net heating value of the vent gas—the parameter that the General Flare Requirements use—“as an indicator of good combustion ignores any effect of steaming.” EPA, Parameters for Properly Designed and Operated Flares (Apr. 2012), <https://www3.epa.gov/airtoxics/flare/2012flaretechreport.pdf>.

<sup>96</sup> EPA has promulgated revised, stricter flare NESHAP standards for similar industries: petroleum refineries, miscellaneous organic chemical manufacturing, ethylene production, and organic liquids distribution facilities. See 80 Fed. Reg. at 75,178 (revising petroleum refinery flare standards to ensure better combustion efficiency); National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) Residual Risk and Technology Review, 85 Fed. Reg. 40,740 (July 7, 2020); National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology Standards Residual Risk and Technology Review for Ethylene Production, 85 Fed. Reg. 40,386 (July 6, 2020); National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing Residual Risk and Technology Review, 85 Fed. Reg. 49,084 (Aug. 12, 2020). The record for these rulemakings demonstrates that flares operating under the general standards do not achieve their requisite destruction efficiency but rather a far lower percentage that fails to assure compliance with the emission standards. See, e.g., Memorandum from Andrew Bouchard to EPA, Dkt. No. EPA-HQ-OAR-2017-0357, Re: Control Option Impacts for Flares Located in the Ethylene Production Source Category, at 8 (Mar. 2019), <https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0357-0017>.

<sup>97</sup> See Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule, 77 Fed. Reg. at 49,503.

information it needs to set emission limits and additional facility safety criteria, and it cannot make this mistake again. Nearly ten years have elapsed since EPA reached this conclusion and yet the agency has failed to conduct critical information gathering. As it stated in supporting documents for the NSPS rulemaking, the agency is already aware that it still lacks “detailed data” necessary for its section 112 review.<sup>98</sup> In 2016, the commenters state they noted several specific areas for which EPA should use information collection authority in order to improve its estimates of HAP emissions from oil and gas sources, including storage vessels, glycol dehydrators, fugitive emissions, and certain operational information.<sup>99</sup> The commenter asserts that EPA must start the process now to obtain this data.

Commenter (0809-Earthjustice) states that EPA now undoubtedly possesses data that it did not in 2012 and on which it could readily draw for the NESHAP reconsideration and new 112(d)(6) review. For example, the commenter provides that EPA has conducted NESHAP rulemakings for related source categories (*e.g.*, fence-line monitoring and improved flare standards in the refinery NESHAP, as discussed below), has conducted enforcement actions and reached consent decrees for oil and gas facilities (*e.g.*, pigging requirements in the 2018 consent decree discussed below), and has received data and information from oil and gas sources in compliance with the NSPS and other rules (*e.g.*, information on storage vessels and equipment leaks pursuant to NSPS OOOO and NSPS OOOOa). According to the commenter, EPA should quickly draw on this data that it already has in hand.

Response I-23-80: These comments regarding the NESHAP are outside the scope of this rulemaking; as such, no response is required.

Comment: Commenter (0789-PA DEP) recommends that EPA consider regulating natural gas emissions from glycol dehydration units and adding methanol to HAP thresholds for 40 CFR Part 63, Subparts HH and HHH.

Response I-23-81: This comment regarding the NESHAP is outside the scope of this rulemaking; as such, no response is required.

### ***23.17.10 Coordination with The International Community***

Comment: Commenter (0746-Methane Action) suggests that in the final rule or next proposal, EPA should incorporate section 115 of the CAA to begin the process of building cooperation with Mexico, Canada, and others whose air quality and public health are mutually affected by the methane releases of neighboring countries via climate change, ozone formation, and other means. The commenter also recommends that EPA work with state and U.S. Agency for International Development to develop model methane rules with cost effective options addressing all possible sources and assist other countries in reducing and removing methane

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<sup>98</sup> See RIA at 4-25.

<sup>99</sup> See Natural Res. Def. Council et al., Technical Comments of Community and Environmental Groups Addressing the Inclusion of Hazardous Air Pollutants in the Oil and Gas Information Collection Request, Docket No. EPA-HQ-OAR-2016-0204, at 3-6 (Aug. 2, 2016), <https://www.regulations.gov/comment/EPA-HQ-OAR-2016-0204-0066>; see also California Communities Against Toxics et al., Comment and Supplement to Petitioners’ 2012 Petition for Reconsideration, Docket No. EPA-HQ-OAR-2015-0747 (March 11, 2016), <https://www.regulations.gov/comment/EPA-HQ-OAR-2015-0747-0030>.

bilaterally, as well as preparing to adopt more aggressive targets not only for methane but for warming itself at the next United Nations Climate Change (UNCC) Conference of the Parties (COP) based on methane removal methods.

Response I-23-82: This comment on section 115 of the CAA is outside the scope of this rulemaking; as such, no response is required.

## **VOLUME TWO**

**Standards of Performance for New, Reconstructed, and Modified  
Sources and Emissions Guidelines for Existing Sources: Response to  
Public Comments on the December 2022 Supplemental Proposed Rule**

**(87 FR 74702, December 6, 2022)**

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## Chapter 1. Introduction

This document provides EPA’s responses to public comments on the proposed *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* rulemaking published in the *Federal Register* on December 6, 2022, at 87 FR 74702 (hereinafter referred to as the December 2022 Supplemental Proposal).

Just over 517,400 public comments were received on the December 2022 Supplemental Proposal. The EPA Docket Center consolidated mass mail campaigns, form letters and petitions into single DCNs, resulting in over 2,200 posted comments, including late comments. (Note: Batches of substantially similar mass mail campaigns, form letters and petitions are considered as a single “unique” comment.). Each comment submitted to the Docket was reviewed and significant comments relevant to this action and submitted within the comment period (totaling just over 2,100 “unique” comments) have been summarized and included in this document.

Of the more than 2,100 “unique” comment letters received over 82 percent originated from individual private citizens, 6 percent are from industry (including industry associations), 4 percent are from environmental and public advocacy groups, 4 percent are mass mail campaigns/petitions (representing over 513,500 individuals), 3 percent are from state, local, federal, and tribal governments/representatives, 1 percent are from other advocacy groups, including financial companies, and less than 1 percent are from academia.

In addition to public comment submissions to the Docket, EPA held a virtual public hearing January 10, 2023, through January 12, 2023, to provide the public the opportunity to present comments and information on the Agency’s proposed updates to NSPS and EGs to reduce methane and other harmful pollution from the oil and natural gas industry. It is worth noting that the virtual public hearing was originally scheduled as a two-day hearing but due to the public’s overwhelming interest, EPA extended the hearing an additional day.

Roughly 300 speakers, from members of the public either representing themselves or speaking on the behalf of one or more organization or agency, provided oral testimony over the course of three days. Live, daily testimonies were recorded by a certified court reporter and documented in official transcripts. Emailed written copies of testimonies and other supporting information received were uploaded separately to the Docket.

The comment period for the December 2022 Supplemental Proposal closed on February 13, 2023. EPA received multiple requests to extend the public comment period (by 30-, 60-, and 90-days). The EPA did not grant an extension to the public comment period, however, as an outgrowth of stakeholder meetings, the EPA requested additional information from stakeholders that was reviewed and considered beyond the comment period closure date. As such, the EPA reviewed and considered all late comments up until and including September 20, 2023.

A general overview of all the comments received follows in Sections 1.1 through 1.4 of this Chapter. More-detailed comments provided by these commenters (some of which are highlighted in the general overview) on the December 2022 Supplemental Proposal have been summarized and included in Chapters 2 through 23, and Appendix A of this document.

## **1.1 Mass Mail Campaigns/Petitions**

More than 80 individual entries submitted to the Docket are categorized as mass mail campaign comments; representing roughly 508,500 of the more than 516,600 public submissions received by the Docket on the December 2022 Supplemental Proposal (> 98 percent).

Mass mail campaigns can be classified as either mailers/form letters or petitions. For the purposes of this Response to Comment (RTC) document, mailers and form letters (including postcards) are comment submissions submitted by separate, individual commenters, but present substantially similar (if not identical) remarks. These campaigns are typically sponsored by an organization/institution. Petitions are pre-written letters or statements (by a sponsoring agency/institution) requesting action that are signed by persons supporting what is stated in the pre-written letter or statement.

Under this proposal, mailers/form letters (including postcards) account for approximately 60 percent of the total number of mass mail campaign comments submitted to and identified by the Docket – representing more than 324,000 private citizens. Most contributors submitted templates provided by the known sponsoring organization(s) without change; however, it is worth noting that a few commenters customized the template(s) – e.g., to include statements describing personal experiences with deteriorating health. Petitions account for about 40 percent of the mass mail campaign comments identified and represent more than 183,000 private citizens.

Roughly 51 percent of mass mail campaign comments were prepared by an unknown sponsoring organization. The remaining campaigns were generated from various known groups and organizations comprised mostly of religion and environmental/public advocacy groups.

Approximately 62 percent of comments prepared by “Private Citizens” included one or more mass mail campaign arguments; however, these comments varied enough to be considered as a separate entry by the Docket. These comments are summarized in section 1.4.1 of this Chapter (as part of the private citizen summary). It is also worth noting that at least one mailer (representing more than 120 people) prepared and submitted remarks in Spanish. These remarks echo comments provided below.

Mass mail comment campaigns uniformly support the December 2022 Supplemental Proposal and applaud EPA’s efforts to reduce methane emissions from industrial sources (the oil and natural gas sector). Campaigns strongly believe that the December 2022 Supplemental Proposal is an essential step forward towards protecting public health and tackling/mitigating climate change, and often stress the point that methane is over 80 times more potent than carbon dioxide. Many of the campaigns cite or reference the amount of methane emissions generated from the oil and gas sector (16 million metric tons) and warn that without immediate

action, methane emissions and its impact on public health, primarily the health of vulnerable populations (e.g., children and communities located near oil and gas industry operations) and the environment will continue to worsen. Several campaigns (including one campaign representing over 350 health professionals and 50 individual health organizations) discuss the health risks and chronic conditions brought about and/or exacerbated by exposure to methane emissions (e.g., asthma, COPD, heart disease, Parkinson's disease, and low birth weight). A small number of petitions and mailers discuss state-specific concerns.

While campaigns agreed that, overall, the December 2022 Supplemental Proposal improves upon the November 2021 Proposal; nearly all the campaigns urge the Agency to further strengthen the final rule. Requests repeatedly made (which were also included under the November 2021 Proposal) include, for example:

- Ensure that operators at wells capture associated gas;
- End routine flaring (except in emergency situations);
- Strengthen the standards to address emissions from storage tanks by making the standards applicable to more tanks; and
- Provide a clear pathway for participation in the Super Emitter Response Program by ensuring communities and citizens can access data and technologies to help reduce methane and other pollutants in the areas where we live and work.

Other suggestions offered (by a few campaigns) include:

- Strengthen leak detection and repair (LDAR) requirements – e.g., require inspections at low-emitting/small wells with leak-prone equipment;
- Maintain zero-emitting controller and pump equipment requirements; and
- Require that abandoned wells are subject to inspections until closure.

A few mass mail campaigns (many of which were prepared by Black Church leaders and congregants) spoke directly on the issue of environmental justice. Largely these campaigns claim that the impacts from exposure to methane emissions (e.g., increases in methane emissions leads to the formation of smog and, consequently, an increase in asthma related events) disproportionately impact low-wealth communities and communities of color, particularly black communities.

At least one petition (with nearly 400 signatures) offers their support for recent science-based updates to the estimates for the social costs of greenhouse gases (SC-GHGs). Specifically, the petition expresses support for the incorporation of a broader range of climate impacts; a lower discount rate (from 3 percent to 2 percent); and the consideration of global estimates of climate damages. One mailer/form letter (representing over 230 people) discusses methane impacts as it relates to economy and market volatility. The petition maintains that businesses and supply chains are directly impacted by methane pollution and support the December 2022 Supplemental Proposal updates and strong methane regulations, which the petition claims will help reduce price uncertainty and stimulate private investment and foster greater innovation.

At least two mailers were deemed out of scope. One mailer/form letter (representing over 2,000

people) that expressed disagreement with EPA’s decision to include compressed natural gas and electricity derived from manure biogas in the proposed updates to the Renewable Fuel Standard (RFS) and urged the EPA to remove the sources as eligible fuels for the RFS and commit to protecting our communities and ecosystems from Concentrated Animal Feeding Operations (CAFOs) instead. The mailer recalls that the proposal claims that manure biogas production has low emissions and points out that the proposal fails to account for multiple highly emissive, intrinsic aspects of manure production, such as enteric fermentation, feed production, animal transport, and off-gassing of leftover manure solids, in its emissions calculations, in addition to addressing the environmental justice impacts of CAFOs on fenceline communities. The other mailer (representing over 3,700 people) called on EPA to “act quickly to address the backlog of judicial nominations currently before the Senate for consideration.”

A list of campaigns received is provided in **Appendix B** to this document. Examples of a few of the mass comment campaigns submitted can be found in **Appendix C** to this document.

## **1.2 General Support/Opposition**

### Support

An estimated 86 percent (or more than 1,800 submissions) of the unique written comments received support one or more of the updates made or the general intent of EPA’s December 2022 Supplemental Proposal. Support for the December 2022 Supplemental Proposal can be broken down by commenter type as follows: over 87 percent originated from individual private citizens (including mass mail campaign variations), 5 percent are from environmental and public advocacy groups, 2 percent are from industry (including industry associations), 4 percent are mass mail campaigns/petitions, 1 percent are from other advocacy groups (including financial companies), and less than 1 percent (combined) are from academia and state, local, federal, and tribal governments/representatives.

Supporters of the December 2022 Supplemental Proposal generally back EPA’s efforts to reduce methane emissions from the oil and gas sector and overwhelmingly believe that it’s a significant step forward to combating climate change (and its impacts on, for example, economic productivity and social welfare), as well as a significant step to improving air quality and protecting overall public health and the environment. These commenters urge the Agency to finalize and enact the strictest possible limits/safeguards to reduce (and eventually eliminate) methane pollution from the oil and natural gas industry. Many of which recap that methane is a potent greenhouse gas (GHG) (traps about 80 times as much as heat as carbon dioxide (CO<sub>2</sub>)) and point to the oil and gas industry as the biggest supplier (together with agriculture).

Several commenters suggest that the standard would achieve cost-effective methane emissions reductions and provide greater certainty about Clean Air Act (CAA) requirements for new, modified, and existing oil and natural gas activities, including the production, processing, transmission, and storage of natural gas and the production of oil. Other commenters highlight that they are working closely with impacted parties – non-governmental organizations (NGOs), unions, community leaders, etc. and other stakeholders – to develop/deploy technologies (e.g.,

continuous, near-continuous and non-continuous advanced methane detection technologies) and to advocate for policies that serve the goals of the Paris Agreement and support the ambitions of the Biden Administration to chart a path toward a legally durable and effective framework for regulating methane that encourages innovation and operational flexibility. At least one commenter suggests that the proposed updates/revisions will create a consistent, level playing field across production basins that span states, like the San Juan Basin, which crosses Colorado and New Mexico, and the Permian Basin, which crosses Texas and New Mexico.

Other commenters express particular concern over the health and wellbeing of communities of color and tribal communities – which they maintain are often disproportionately impacted by harmful air pollution from oil and gas operations – and agree that the December 2022 Supplemental Proposal could aid in addressing these environmental justice issues.

While commenters generally support the December 2022 Supplemental Proposal, many suggest that the proposed changes do not go far enough and called on the EPA to further tighten rules surrounding the release of methane emissions from the oil and natural gas industry. In such cases, commenters highlight instances where the rule could be improved upon (often pertaining to flaring, storage tanks, and the super emitter response program) and present one or more recommendations to further strengthen requirements. It is worth noting that many of these recommendations (and areas of concern) are similar as those offered in one or more mass campaign mailers received, as discussed under section 1.1 of this Chapter.

### Oppose

Approximately 8 percent (or more than 170 submissions) of the unique written comments received (largely from industry/trade association representatives, followed by private citizens, government officials/organizations, nonprofit organizations and other advocacy groups) generally oppose one or more of what was proposed in the December 2022 Supplemental Proposal. It is worth noting that a small number of commenters (comprised mostly of private citizens) outright refute climate change/global warming, and strongly object to the proposal.

While some commenters acknowledge that reducing methane emissions from the oil and gas industry is a necessary and important step towards mitigating climate change impacts, most assert that the proposed updates are unnecessary and unreasonable and an overreach. Many of these commenters contend that the December 2022 Supplemental Proposal does not adequately provide for (as required) cost-effective controls, nor does it ensure that the newly imposed requirements are not overly burdensome to the entire scope of the regulated community that are covered by the regulations, or the agencies that are required to implement these emission standards. Commenters urge the EPA to consider additional flexibilities that can minimize potential impacts (particularly impacts to small businesses) while accomplishing the goal of reducing methane emissions from oil and natural gas production.

Numerous commenters strongly oppose EPA’s approach to determine the “value of a statistical life” or social cost value; largely arguing that this approach is unjust and poses serious ethical concerns – as the value of life should not be determined/measured by their ability or “willingness to pay.” Moreover, commenters submit that the proposals are not in congruence

with environmental justice principles, due to its discrimination based upon wealth, and should be revised before finalization.

Several commenters express concerns that the December 2022 Supplemental Proposal will significantly impact oil and natural gas operations and costs, and unfairly and disproportionately impact small businesses and tribal communities, as well as significantly and negatively impact the economy (e.g., increases in gas prices and job losses). Overall, commenters disagree with EPA's decision to include marginal wells – or low production wells – which historically have been exempted; arguing that emissions from production operations are insignificant – marginal wells have a diminished capacity to emit methane and can become economically unviable for small independent drillers if new (inspection and repair) rules are too costly. These commenters believe that the EPA should maintain exemption status. Furthermore, commenters generally oppose EPA's one-size-fits all approach; calling it misguided and stress the importance of the oil and natural gas industry to state and local economies. Many of these commenters underscore the point that states, like Alaska heavily regulate oil and gas productions within their state, and therefore question whether the proposal would significantly reduce methane emissions as claimed.

A few commenters (representing tribal communicates) worry that the December 2022 Supplemental Proposal, as written, will have a direct financial impact on the tribal lands – i.e., tribal communities would be impacted by the rule both as a regulator and as an operator of oil and gas development facilities.

Some commenters ask that the Agency establish a realistic timeframe for compliance and implementation, and where possible streamline/simplify standards, including those pertaining to the state planning process (e.g., LDAR standards) to ensure prompt and efficient implementation of these new emissions guidelines (EGs).

#### Other Comment Types

Nearly 2 percent of the unique comments (approximately 33 comments, mostly from industry and government representatives) request that EPA extend the public comment period for the proposed rule; citing that the amount of time granted to prepare and submit remarks is insufficient.

Approximately 54 percent (roughly 100 comments, primarily from private citizens) of the unique comments received, conveyed general concerns about the environment and/or public health, but did not specifically comment on the proposed updates.

### **1.3 Summary of Public Hearing Comments**

As previously noted, the EPA held a virtual public hearing January 10, 2023, through January 12, 2023, to provide the public the opportunity to present comments and information on the Agency's proposed updates to NSPS and EGs to reduce methane and other harmful pollution from the oil and natural gas industry. It is worth noting that the virtual public hearing was originally scheduled as a two-day hearing but due to the public's overwhelming interest, EPA

extended the hearing an additional day. Over the course of three days, nearly 300 speakers (roughly 100 speakers per day), from members of the public either representing themselves or speaking on the behalf of one or more organization or agency, provided oral testimony. Testimonies can be broken down by commenter type as follows: Over 65 percent originated from environmental and public advocacy groups (including various nonprofits and faith communities), an estimated 30 percent originated from individual private citizens (including students, retirees, community members and volunteers), 3 percent originated from industry (including industry associations), and 1 percent originated from government agencies representatives and elected officials. It is worth noting that some speakers prepared and submitted to the Docket separate, more detailed comments. These remarks are discussed elsewhere in this document. The public hearing transcripts for the virtual public hearing are accessible at [regulations.gov](https://www.regulations.gov) (see EPA-HQ-OAR-2021-0317; search “2022 Supplemental Proposal Public Hearing”).

Environmental and public advocacy groups generally support EPA’s December 2022 Supplemental Proposal to reduce methane and other harmful pollution from the oil and natural gas industry. Many of the speakers remind that methane is a strong GHG – 86 more times potent than carbon dioxide, and a major contributor to climate change, as well as poses a hazard to human health. While speakers agree that the proposed updates would further protect public health and help mitigate climate change impacts, they urge the Agency to finalize the strongest most comprehensive rule, and offer as such, one or more recommendations aimed at strengthening the proposal. More specifically, speakers ask that the Agency to: 1) follow the lead of states like Colorado and New Mexico and prohibit the practice of routine flaring; 2) strengthen the standards to address emissions from storage tanks; and 3) supply a clear pathway for communities and individuals to take part and engage in the Super-Emitter Response Program.

Private citizens testimonies echo many of the remarks made by environmental and public advocacy groups – they generally support the proposed updates and applaud the Agency efforts to reduce methane from the oil and gas industry. Many of the speakers reiterate environmental (e.g., extreme weather) and public health concerns (e.g., low-birth weight) resulting from methane emissions from the oil and gas productions. Additionally, several speakers describe personal experiences and/or various health impacts which they believe are a result of exposure to air pollutants – methane, from oil and gas facilities. Some speakers also express concerns about the health of communities living near oil and gas facilities – who they maintain, pay a higher cost (disproportionally impacted) through increases in healthcare costs, a decrease in quality of life and other indirect costs. A few speakers express concern over relying on oil and gas industry volunteering efforts as the primary means to reduce methane emissions and address climate change and protect human health, and all call on the EPA to finalize the strongest most comprehensive rule.

Industry representatives are generally supportive of the December 2022 Supplemental Proposal; many reintegrating their commitment to supporting public policies that protect the environment while ensuring a safe, reliable, and resilient energy transmission system that provides affordable energy nationwide. Most speakers underscore the point that methane is harmful pollutant and acknowledge that the oil and gas industry is a large contributor. At least



one speaker (representing roughly 250,000 businesses spread throughout the U.S.) describes the negative impacts of methane emissions on local/state economies. For EPA’s consideration, several speakers testify to one or more of services and/or low-cost, innovative products/equipment/ technologies currently available (and manufactured/offered by them) that they contend are capable of efficiently reducing wasteful methane emissions. While many speakers agree with the overall intent of the December 2022 Supplement Proposal, some speakers express concern over one or more provision – e.g., on centrifugal compressors, at least one speaker feels that the new dry seal threshold should be revisited. At least one speaker warns against a lack of accountability for hydrocarbon waste streams.

Overall speakers representing governmental agencies/representatives (i.e., state and local/tribal governments) overwhelmingly support the December Supplemental Proposal and EPA’s overall intent to limit/reduce methane pollution from oil and gas operations; asking that the Agency finalize strong, comprehensive new and existing rules to cut methane pollution. While speakers identify several of the requirements which they agree-on – e.g., the use of zero-emitting technologies – they also maintain that more can be done – e.g., the December 2022 Supplemental Proposal can be further strengthened by banning the practice of routine flaring.

One speaker (a newly elected state representative) spoke specifically on the impacts of methane emissions on tribal communities and stated that the December 2022 Supplemental Proposal is an important step towards addressing the climate crisis and protecting public health.

## **1.4 Summary of General Positions by Commenter Type**

### ***1.4.1 Private Citizens***

#### **Support**

Most private citizens (nearly 92 percent of the “unique” comments received) generally support one or more requirements of the December 2022 Supplemental Proposal. Like public submissions included as part of mass mail campaigns, a number of these commenters feel that while the December 2022 Supplemental Proposal constitutes a major step forward in combating the climate crisis by reducing methane emissions from the oil and gas, many urge the Agency to go further and presented one or more recommendations to further strengthen requirements. It is worth noting that many of the recommendations presented – e.g., close existing loopholes and ban flaring, strengthen standards to address emissions from storage tanks, and provide a clear pathway for participation in the Super Emitter Response Program – duplicate those offered in one or more mass campaign mailer, as noted in the above section.

Several commenters reiterate that methane is a potent GHG (80 times the warming power of carbon dioxide). These commenters believe that global climate change poses a very serious threat and without immediate action, methane emissions from the oil and gas industry – leaks from a well, storage tank, pipeline, pump, compressor station or any other structure – and its impact on the environment and on public health, primarily the health of vulnerable populations (e.g., children and low-income and communities of color) will continue to worsen. Commenters presented examples of environmental (wildfires, droughts, severity of storms,

etc.) and public health impacts (asthma, chronic respiratory diseases, etc.), which they believe are a result of climate change and/or impacts from the air pollution emitted by the oil and gas industry. Plugging methane leaks, for many of these commenters, is considered a relatively low-hanging fruit – i.e., an efficient and effective way for oil and gas facilities to reduce methane emissions without having to pass shortfalls from unclaimed, leaked methane to consumers.

### Oppose

Approximately 4 percent of the “unique” comments received from private citizens generally oppose one or more requirements proposed in the December 2022 Supplemental Proposal. Overall, commenters believe that the December 2022 Supplemental Proposal imposes additional, unnecessary and burdensome regulations and standards on a large segment of the oil and gas industry, while doing little to improve environment conditions or address/consider potential economic impacts – increases in electricity rates – thus, unnecessarily hurting Americans.

Foremost, commenters largely object to EPA’s approach in calculating the “value of a statistical life” and strongly encourage the Agency to reconsider; arguing that quality of life should not be dependent on someone’s “willingness to pay”. At least one commenter suggests that if EPA were to consider all human lives as having equal value, regardless of what country or economic circumstances people live in, then the cost to the oil and natural gas industries will be sufficient to incentivize appropriate action. As currently framed, the commenter believes that the proposed changes will not result in necessary changes within these industries.

Similarly, commenters recommend that the EPA withdraw its External Review Draft “Report on the Social Cost of Greenhouse Gases,” and revise its analysis to correct the material deficiencies described in these comments. At least one commenter suggests that the peer review report is not comparable to a report with replicable data – the essential characteristic of the scientific method – and transparency – unfettered access to the assumptions, algorithms, software code, and data used. Another commenter briefly discusses the challenge to assigning and appropriate value of the social discount rate – the appropriate approach to social discounting depends on ethical judgments as well and argues that the Agency’s analysis fails to adequately grapple with these challenges, instead noting that the Agency uses a “descriptive approach,” which involves “inferring the discount rate from market rates of return.”

Some commenters believe the December 2022 Supplemental Proposal requirements are burdensome and unnecessary, with a few commenters questioning the validity of climate change claims. Commenters suggest that fossil fuels are a critical part of the economy and essential to keeping energy costs low, and warn that, if enacted as written, the proposal would lead to economic hardships. At least one commenter suggests that the oil and gas industry in their state (Michigan) does not warrant new regulations; arguing that negligible emissions generated by the sector within the state are not enough to justify inclusion and recommends that the EPA focus on large emitters of methane.

In some cases, commenters propose one or more changes (or considerations) to the December

2022 Supplemental Proposal aimed at minimizing potential regulatory and financial impacts on businesses and the general public, while still accomplishing the goal of reducing methane emissions from oil and natural gas production— e.g., provide an opportunity for operators to mitigate detected compliance issues instead of immediately classifying them as violations. In other cases, commenters feel that the December 2022 Supplemental Proposal, as written, fails to adequately protect human health and offer several suggestions/recommendations aimed at strengthening the Proposal.

### Other

Approximately 5 percent of the comments received from private citizens include broad remarks about the environment, public health, etc., but do not specifically comment on the proposed rule.

One private citizen requested an extension to the public comment period to ensure appropriate time to review new regulations and accompanying documents, as well as allow institutions a proper amount of time to conduct their own research and post their comments.

### ***1.4.2 Academia***

Comments received from academia unanimously (100 percent) support EPA’s December 2022 Supplemental Proposal that builds upon the November 2021 Proposal to control methane emissions from new and existing sources in the oil and gas industry. While commenters largely support the general intent of the rule, nearly all believe that the supplemental proposal, as written, does not go far enough, and in some cases, discuss specific areas in the rule where they believe further improvements, or additional clarification are warranted, and offered one or more recommendations aimed at toughening/clarifying EPA’s final rule (and its underlying analysis) and maximizing net benefits – e.g., in regard to strengthening the RIA, EPA should extend the timeframe of its analysis to quantify net benefits past 2035.

On the whole, commenters agree that the *Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, ‘Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review – EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* represent a significant advance and update on earlier social cost of GHG numbers put forward by the Interagency Working Group.

Several commenters, however, provide suggested changes for EPA to consider. For example, at least one commenter, who’s remarks centered around ‘dynamic discounting’ believes that the central numerical value for the Social Cost of Carbon (SCC) in the EPA report and the discounting methods used to reach this value have strong independent support from the academic literature – i.e., are consistent with academic findings and broader international policy guidance. While the commenter acknowledges that the numerical values for several of the underlying parameters are consistent with academic findings and broader international policy guidance, they

suggest that the EPA report is overly constrained by its purely positive framework and urge the Agency to put more weight on normative arguments. The commenter maintains that this approach/position would be clearly justified by the latest academic literature and would also make it easier for EPA to justify its modeling choices.

Similarly, another commenter offers additional technical observations – e.g., the EPA report would benefit from referring to its discounting approach as ‘risk-adjusted’ rather than ‘dynamic’ – concerning the summary statistics of the SCC, beyond the mean, that are given in the EPA report, and question whether these statistics/data provide information that is likely to be relevant for policy purposes. The commenter recommends that the EPA focus solely on the mean estimate of the SCC based on the central discount rate. Another commenter asserts that EPA’s discount rate range is too high based on the evidence presented by the Agency and recommends that the Agency shift down its short-run, risk-free discount rate range to 0.5%–2.5% with a central rate of 1.5%. While one commenter believes that EPA appropriately accounts for climate damages globally in the draft report, and that adopting a global value is economically sound and consistent with the approach EPA first developed under the George W. Bush administration, and in line with Circular A-4 (2003)’s recommendation that agencies report “effects beyond the borders of the United States”; the commenter asserts that this approach has sparked unmeritorious legal challenges claiming an inconsistency with standard administrative practice, and as a result, recommends that the EPA should situate its consideration of global climate damages in administrative precedent.

Another commenter expresses their appreciation and support for EPA’s proposed framework for enabling use of advanced technologies in the December 2022 Supplemental Proposal – reflecting how rapid advancements of such technologies can lead to greater emission reductions through earlier and more frequent detection of fugitive emissions as well as intermittent and persistent emission events. While the commenter agrees that the December 2022 Supplemental Proposal includes essential elements to incentivize the deployment of advanced technologies thereby securing larger methane emissions reductions more quickly, including the advanced technology matrix, they offered several comments that identify areas for EPA to align the matrix requirements to encourage owners and operators to use advanced technologies to ensure greater and more cost-effective emission reductions.

### ***1.4.3 Industry/Trade Association***

#### **Support**

Roughly 29 percent of comments received from industry representatives (including industry associations) on EPA’s supplemental action, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (December 6, 2022), generally support one or more requirements of the December 2022 Supplemental Proposal.

Most industry representatives prepared technical remarks of the December 2022 Supplemental Proposal based on factors that are unique to their members. Some commenters formally endorsed

or incorporate (by reference) one or more arguments made by other trade groups and industry stakeholders. While commenters support many aspects of the December 2022 Supplemental Proposal as drafted, nearly all the commenters agree that the EPA should continue to build on the progress in the December 2022 Supplemental Proposal and highlight specific areas in the proposal where they believe further improvements, or additional clarification are warranted. Specific areas of concern and/or recommendations made vary; however, two central themes or areas often discussed include: usage of advanced methane monitoring technologies and the allowance of states to leverage existing state programs.

A majority of industry/trade association commenters appreciate and support EPA's proposed framework for enabling use of advanced technologies in the December 2022 Supplemental Proposal (as an alternative to AVO, OGI, or Method 21) for methane LDAR, many also support efforts to further refine these frameworks to ensure that advanced methane monitoring technologies, including alternative periodic screening and continuous monitoring systems, can be successfully utilized by operators and that their ongoing development will be incentivized. These comments and recommendations generally centered around four (4) key points:

- Regulatory treatment of camera-based continuous monitoring systems under the supplemental proposal;
- Incentive for operators to utilize advanced technologies under the screening matrix;
- Alternative test methods application and use of FEAST modeling as part of an application Consideration of the intermittency of super-emitters in EPA's FEAST modeling simulations; and
- Use of cameras to comply with flare inspection under Method 22.

Some commenters reaffirm their commitment to reducing emissions and noted that they are proactively working with state regulatory agencies to develop reasonable requirements for the protection of air quality. These commenters underscore the point that many state agencies have already implemented regulations to reduce VOC and methane emissions from the same source categories included in NSPS OOOOb and EG OOOOc. In an effort to reduce administrative burdens and provide flexibility to states in the development and submittal of state plans (as intended by Congress), commenters requests that the EPA allow states to leverage existing state programs by submitting total program evaluations to demonstrate equivalency with EG OOOOc, which, according to at least one commenter is consistent with CAA section 111(d) and will promote, rather than disincentivize, future state efforts to adopt state programs for the control of emissions from the oil and natural gas industry, and other industry sectors.

It is worth noting that several commenters pitched company-owned methane reducing technologies, which they maintain are proven, scalable and cost-effective – e.g., Crusoe's Digital Flare Mitigation® (DFM) systems BSM's NIRview™, ZEVAC's Zero Emission Vacuum and Compressor, and Qnergy's Compressed Air Pneumatics, CAP3 system – emerging or currently available.

## Oppose

Roughly 51 percent of comments received from industry representatives (including industry associations) on EPA's December 2022 Supplemental Proposal, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 Fed. Reg. 74,702 (December 6, 2022), generally oppose one or more requirements of the Proposal.

Most industry representatives prepared individual, separate technical remarks – e.g., on record keeping and reporting requirements to processing of well plugging operations to encouraging community involvement that results in unqualified, unprotected residents visiting oil and gas production facilities – on the supplemental proposal based on factors that are unique to their members. However, many of the commenters express concerns regarding the supplemental proposal's (disproportional) impact on small oil and gas producers/businesses – many of which operate low production wells (i.e., wells with a production level less than 15 barrels per day [or equivalent gas production]) – and the states that rely on these producers/businesses for economic viability.

Commenters worry over their members' ability to implement and comply with regulations; stating that many of their members, for example, are limited in staffing and may not be able to manage day-to-day office activities and field maintenance work efficiently and effectively, without substantial support. Consequently, several commenters ask that the EPA maintain the low-production well exemption, which they contend would provide significant relief for small businesses without measurable environmental impacts.

Several commenters acknowledge that reductions in emissions from the oil and gas sector are needed to mitigate the predicted impacts of global climate change. To that end, commenters describe existing voluntary efforts and those currently underway by industry leaders to address methane emissions and improve air quality. Moreover, many of these commenters strongly object the proposal's one-size-fits all approach, which they believe fails to adequately account for impacts to small businesses – proposal largely ignores the fact that different wells have different production and emission characteristics. At least one commenter proclaims that EPA never revised the LDAR technology requirements to reflect inclusion of low production wells, which according to the commenter is significant, because the cost-effectiveness of an LDAR program is very different for large well sites compared to small business low production wells. A few commenters worry about compliance and implementation impacts on wells located in predominantly rural areas and have limited access to power.

In addition, some commenters assert that EPA's December 2022 Supplemental Proposal fails to consider the third-party U.S. DOE study titled, "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells," on low-production well emission profiles. Many of the commenters suggests that the Agency review and consider data presented in the study when developing a baseline that shows distinctions between large wells and low

production wells and the difference that exist between types of wells – when developing low production well regulations. At least one commenter suggests that the EPA reconstruct the regulation to provide that as wells decline to the low production well threshold, these wells would move into the low production well requirements.

Other commenters formally endorsed or incorporate (by reference) one or more arguments made by other trade groups and industry stakeholders.

### Other

Approximately 12 percent of the industry comments respectfully request an extension of the public comment period (anywhere from 60- to 90-days, with one commenter requesting a 30-day extension) for EPA's *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Supplemental Proposed Rule)*; citing, in general, insufficient time to respond adequately and appropriately – to fully review the December 2022 Supplemental Proposal, the supporting material, and provide meaningful comments. Several commenters specifically point to the breadth (number of pages) and depth of the issues in the proposal, as well as the estimations of significant cost implications.

Many of these commenters question the timing of the proposal as its publication date coincide with several other recently release draft rules – as lengthy and complicated, including BLM's Waste Prevention, Production Subject to Royalties and Resource Conservation rule; proposed revisions to CAA section 111(d) regulations [published in the *Federal Register* on December 27, 2022]; proposed revisions to the definition of “waters of the United States” (WOTUS), and public comment period spans extending over three (3) holidays, ultimately reducing the amount of time stakeholders must respond.

At least one commenter (representing a professional trade association located in Alaska) explains that several of the proposed rules sweeping changes to the performance standards and monitoring methods that oil and gas producers must deploy to control and monitor methane emissions in multiple operational sectors may not be feasible in the harsh climatic conditions, nor realistic or practical for Alaska's North Slope operations. Due to Alaska unique conditions, the commenter appreciates a deadline extension to allow for meaningful comments.

Furthermore, less than 9 percent of commenters submitted separate supportive documents, including copywritten materials (in addition to their primary comments).

### ***1.4.4 State/Local/Tribal/Federal Governments***

#### Oppose

Roughly half (approximately 55 percent, made up exclusively of state and tribal agencies) of the comments submitted by government agencies and representatives generally opposed, as written,

*EPA's Supplemental Notice of Proposed Rulemaking: Standards of Performance for New Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Published 87 Fed. Reg. 74702 (December 6, 2022).*

Specific concerns vary by commenter. In some cases, commenters restate or incorporate by reference concerns outlined in their initial comments submitted on the original proposal.

While most commenters appreciate EPA's work in drafting the December 2022 Supplemental Proposal and appreciate the underlying goal to protect public health, safety, and the environment, many believe the proposed EGs are redundant (due to existing oil and natural gas state-level laws and regulations) and create unnecessary confusion and regulatory burdens –e.g., making implementation infeasible given the massive increase of affected facilities and the corresponding mountain of additional requirements pertaining to compliance, permitting, emissions inventories, the development of State plans, and other air quality aspects. Furthermore, commenters maintain that the December 2022 Supplemental Proposal also lays out unrealistic assumptions and artificially high metrics to estimate the climate benefits of the rule. In general, commenters urge the EPA to reconsider the proposed EGs and consolidate existing applicable regulations and streamline proposed requirements for new and existing sources in the oil and natural gas industry.

Commenters maintain that EPA's "one-size-fits-all" approach does not adequately consider or reflect how rulemakings may affect certain states differently than others. One commenter asserts that the December 2022 Supplemental Proposal has an outsized impact upon states whose economies are resource dependent; adding that many of these states have significantly smaller staffing and less funding available compared to other state agencies. At least one commenter claims that the EPA has not performed a proper Unfunded Mandate Reform Act (UMRA) analysis because the proposal and its analysis fails to represent potential costs that state-level regulatory agencies will have to bear to meet the implementation requirements of the supplemental proposal. In similar remarks, some commenters express their concerns over the December 2022 Supplemental Proposal requirements (i.e., EG OOOOc) for state-level agencies to justify and apply for an alternative standard that takes into consideration the remaining useful life (RULOF) of a designated facility and other factors outlined in the proposed regulatory text; arguing that these requirements would create impractical workloads and resource burdens – on state regulatory agencies due to the sheer volume of affected sources that should be considered for remaining useful life and other factors. Commenters agree that the Agency must provide sufficient funding to offset or lessen the burden placed on states under the proposed rule and any resultant supplemental actions, as well as provide adequate time for states to meaningfully consider EPA final action and develop an implementation plan accordingly.

Regarding the super emitter program, at least one commenter asserts that the program is unlawful. The commenter further expresses their concerns over the redundancy or conflict with established state delegated programs, the lack of clear communication to delegated authorities of super-emitter events, the potential time-lag present in third-party monitoring systems, the lack of



established ground truthing protocol and the perception these third-party monitors will have some fashion of non-delegated regulatory authority, to name a few.

A few commenters (including one commenter representing a coalition of local governments) express their concerns that the proposal exceeds EPA's statutory authority under the CAA and will significantly limit domestic energy supply. Many of the commenters underscore that the oil and gas industry is currently heavily regulated by state agencies – i.e., they currently comply with a number of state-specific emission guidelines, monitoring requirements, and technical requirements for existing storage tanks, separation vessels, dehydration units, pumps and controllers, and compressor stations, and warn against additional regulations – during a time where energy supply is fluctuating as a result of international conflict – that could result in result in unpredictability and ambiguity for industry operators (particularly on small businesses in the oil and gas production sector) as well as state regulators.

At least one commenter asserts that the December 2022 Supplemental Proposal does not account for increased costs for alternate sources of energy due to loss of natural gas production if the wells are plugged rather than implementing emission control equipment and contends that a large amount of oil and gas would be removed from the marketplace, increasing costs to the public.

Several commenters suggest that the Agency streamline regulatory requirements (e.g., for various source categories, including storage vessels, controllers, pumps, etc.) by allowing both the industry and state regulators to determine regulatory applicability based on a singular date; adding that this approach would enable states then streamline their regulations for the oil and gas industry when submitting their state implementation plans (SIPs) to comply with the emission guideline. At least one commenter requests that the EPA add the following sources – glycol dehydration units, pigging operations threshold for multiple sources controlled by a single device – to the existing proposed regulatory requirements.

Several other commenters (including tribal groups) suggests that the December 2022 Supplemental Proposal lacks transparency. Commenters suggests that a lack of consultation and simultaneous comment periods on multiple significant proposed rules prevents meaningful engagement and completely disregards cooperative federalism. Commenters strongly recommend that the Agency conduct meaningful engagement with state/tribal co-regulators before promulgating a final rule. One commenter (representing tribal businesses and community) reminds that their members rely on oil and natural gas production as a revenue source instead of a tax base. The commenter adds that while there are parts of the proposed rule which would impose more stringent regulation that they are in support of, the commenter cautions the EPA against overregulation and ask that the Agency defer to tribal law. Moreover, one commenter states that the program is a direct attack on tribal sovereignty.

Commenters express additional concerns over the proposed timeframe for compliance and implementation and strongly believe that the supplemental proposal has the potential to disproportionately impact tribal regulatory agencies and urge the Agency to ensure funding

mechanisms for tribal entities that implement these regulations. At least one tribal agency commented on applicability as it relates to facilities located in Alaska recommends that any requirement, or exemption, that is written specifically as applicable to those facilities also include language allowing for a similarly relaxed requirement or exemption for any facility located elsewhere that can show just cause as determined by the Administrator.

### Support

Roughly 21 percent of states, federal and tribal representatives generally support one or more of the requirements in the December 2022 Supplemental Proposal and encourage the quick adoption of *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* rulemaking.

Commenters prepared and submitted individual, separate remarks on the proposed rule based on factors that are unique to their state or tribal community. Some commenters restate or incorporated by reference remarks outlined in their initial comments submitted on the November 2021 Proposal. Specific areas of support vary by commenter and commenter type – e.g., support for closure plans and super emitter response program requirements.

While commenters largely support the proposal as written, a few commenters offered technical comments and/or one or more recommendations aimed at further strengthening the supplemental proposal/rules. Some concerns expressed (i.e., surrounding compliance implementation, meaningful engagement, and the need for the Federal agency to provide states/local/tribal governments with adequate funding support) mimic those expressed by non-governmental representatives (including private citizens, environmental groups, etc.).

In addition, a number of commenters (including a Trustee of state employees) share recommendations that are identical to or resemble recommendations proposed by non-governmental representatives (including private citizens, environmental groups, etc.) – such as, ban and/or limit flaring to emergencies situations only, strengthen requirements for storage tanks, provide a clear pathway for communities and individuals to participate and engage in the Super Emitter Response Program, expand routine monitoring (increase frequency), transitioning to zero-emitting technologies for controllers.

At least one comment letter (representing multiple Members of Congress) requests that EPA consider consultation with small, family-owned businesses/producers who are impacted by the rule; adding that while many larger entities can comply with new regulations, smaller companies may struggle to adopt technologies mandated by EPA, thus further highlighting the importance of technology flexibility.

Commenters applaud the EPA's efforts, in general, in creating a more comprehensive approach to reducing methane – a potent GHG – from the oil and natural gas industry; adding an action that will help the U.S. meet its climate change mitigation goals. At large, commenters believe that the

implementation of the supplemental proposal (and its adjoining rule) will result in significant climate benefits as well as direct health benefits to communities harmed by local and regional emissions, including low-wealth, communities of color (including tribal communities).

Overall commenters believe that the December 2022 Supplemental Proposal (and its adjoining rule) will ensure innovation is encouraged in the private sector and maximize emission reductions at the least cost to consumers as well as ensure accountability and reliability in, for example, identifying methane and VOC leaks through the use of advance monitoring technologies. Commenters urge EPA to work together with states to promulgate regulations that comply with the CAA and allow for the broadest variety of methane emissions detection technologies, or combinations of technologies, while driving towards the use of best available technologies to measure actual site-level emissions.

One commenter (representing over 150 principal member Tribes) appreciates EPA's public outreach efforts and expressed desire to collect input from a broad range of stakeholders; however, the commenter requests that these efforts not only continue, but that they be expanded, particularly with respect to coordination and consultation with Indian Tribes; noting that each tribe's unique circumstances must be evaluated. The commenter stresses the importance of addressing environmental justice implications of the proposed action and seek to advance equity for all; however, they underscore the point that that concern for environmental justice cannot replace government-to-government consultation with Tribes. The commenter (along with separate tribal organization) underscores the point that tribes are sovereign nations with self-determination, as such, one of the commenters adds that they cannot be treated like EJ communities.

At least one commenter urges the EPA to reconsider its proposal to solely rely on the use of audio, visual and olfactory (AVO) monitoring techniques at wellhead-only or small well sites.

Another commenter's (representing a federal lobbying group) remarks primarily focus on vulnerabilities and the methane proposal's use of the Interagency Working Group's (IWG) social cost of greenhouse gas (SC-GHG) estimates and on EPA's External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances ("External Review Draft"). The commenter identifies one or more areas of concern – e.g., EPA's decisions to include the External Review Draft in the Methane Proposal also hinders the credibility of the External Review Draft and urges the Agency to withdraw the External Review Draft from this rulemaking and defer to the IWG's process for updating the SC-GHG values. In a similar but contrasting comment, one commenter (representing a bipartisan coalition of governors) applauds the inclusion and utilization of updated estimated values for the SC-GHG in the proposal's accompanying draft report, *The Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. According to the commenter, these estimates are informed by the latest science, account for global damage estimates, and include an appropriate range of discount rates, and is particularly timely as action from the IWG remains unfinished.

## Extension

Remaining comments (approximately 24 percent, predominately state representatives) ask that the EPA extend the public comment period (anywhere from 30- to 60-days); citing, in general, insufficient time to respond adequately and appropriately. Nearly all commenters reference the length and complexity of EPA's proposal (hundreds of pages and multiple supportive documents to review) as the primary reason for requesting an extension and insist that an extension will lead to a more robust and comprehensive set of comments that will ultimately lead to a stronger final rule. At least one commenter suggests that an extension shouldn't be a problem since there is no statutory or court ordered deadline associated with the proposed rule.

### ***1.4.5 Environmental and Public Advocacy Groups***

## Support

Comments (about 90 percent) from environmental and public advocacy groups overwhelmingly support (one or more requirements found) the December 2022 Supplemental Proposal and appreciate the Agency's efforts to reduce methane emissions from oil and gas operations and urge the Agency to swiftly adopt the strongest possible rules.

Several commenters briefly discuss climate change impacts, including its effect on public health (especially on families living near gas wells, and the safety and livelihoods of indigenous and low-income communities/communities of color), and in some cases, even offer state-specific examples of violations or air quality. Commenters agree that the December 2022 Supplemental Proposal (and its adjourning rule) is one of the best opportunities to help slow the rate of climate change and protect our health.

While supportive of the Agency's efforts to reduce emissions, many of the commenters also echo feelings noted by other commenter types (including private citizens, academia, industry, etc.) that the proposed rule does not go far enough.

Consequently, many of these commenters' support and reiterate one or more proposed regulatory changes (many of which have been discussed already) also supported by non-environmental and public advocacy groups – e.g., banning/limiting flaring to emergency events only, requiring a zero-percent leak rate from controllers, addressing leaks from storage tanks, providing a clear pathway for communities and individuals to participate in the Super Emitter Response Program. Regarding the proposed timeline, at least one commenter, recommends that the EPA offer states and gas companies' incentives for the early adoption of these necessary public health standards while also increasing air monitoring at oil and gas facilities to identify malfunctioning equipment prior to enforcement deadlines.

At least one commenter disagrees with industry concerns that the proposed rule would be overly costly/burdensome with little benefits; stating that the EPA systematically underestimates methane emissions from oil and gas drilling and transport activities, the benefits of controlling

those emissions also have been underestimated (according to Institute for Energy Economics and Financial Analysis finding) and as a result, the oil and gas industry margins will be greater—not smaller—if the new EPA methane rules are implemented.

One commenter refers to research done by the University of Cincinnati in southeastern Ohio, that suggests wells that produce less than a barrel of oil per day leak into the atmosphere more than 100 percent of their reported gas production. According to the commenter, gas wasted by these low-producing wells could meet the heating and cooking needs of nearly every home in the State of Ohio.

A small number of comments (approximately 6 percent) prepared and submitted are written copies of verbal testimonies presented at the January 2023 public hearing and/or copies of supporting documents referenced in verbal testimonies.

### Oppose

Roughly 5 percent of commenters generally opposed the December 2022 Supplemental Proposal, as written; suggesting it is flawed and lacks transparency, and requests that the Agency withdraw the rule. Specific concerns vary by commenter. Several of the commenters suggest that the EPA's December 2022 Supplemental Proposal (and its adjoining rule) overstep EPA's authority. At least one commenter asserts that the Agency continues to ignore/arbitrarily disregard the principles and regulatory analysis established in Circular A-4 (2003) – a guidance document to federal agencies on developing regulatory analyses required by Executive Order 12866, and the requirement of a 7 percent discount rate. At least one commenter questions the accuracy of EPA's data and stress the need for physical evidence verse speculation or theories. In a similar comment, after thoroughly reviewing EPA's draft new methodology, one commenter finds that the methodology and estimates are not yet scientifically reliable and robust for policy use – i.e., contains multiple significant technical issues and does not satisfy the National Academies of Sciences, Engineering, and Medicine (NASEM) recommendations. The commenter maintains that key issues – e.g., increase transparency, justification, scientific basis, and incorporation of uncertainty should be addressed before the estimates are deployed to inform policy, for this rule and otherwise. Another commenter objects to the SCC model used for the rule's cost-benefit analyses; moreover, ask that EPA revise its supporting documents – e.g., Fact Sheet and TSD to account for/consider rises in sea-level.

### Other

Remaining commenters (about 6 percent) requested an extension of the public comment period (by an additional 90-days) or an additional day to the scheduled January 2023 public hearings. At least one commenter, cited insufficient time to respond to requests adequately and appropriately as a reasoning. Another commenter (interested in extending the public hearing) suggests that interest to participate in scheduled hearings was high and as a result, registration slots to provide

verbal testimonies filled nearly a month before the hearing was scheduled to take place, leaving out remaining interested participants.

#### ***1.4.6 Other/Other Advocacy Groups***

##### **Support**

Most comments (over 80 percent) received from other advocacy groups (comprised mostly of private equity/investment firms and union organizations) support the proposed updates to the NSPS and EG (under the December 2022 Supplemental Proposal). Overall, commenters commend EPA's efforts to adopt commonsense, cost-effective regulations that reduce transition risks to oil and gas investments, while addressing/reducing methane emissions from oil and gas operations – the largest source of industrial methane emissions in the U.S. At large, commenters encourage EPA to continue to build on the progress in the December 2022 Supplemental Proposal and move swiftly to finalize the strongest, most comprehensive rules and standards possible.

Commenters (representing investors/investment management firms) stress their commitment to integrating environmental, social, and governance (ESG) factors into investment management decisions, and ask that the Agency establish a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported methane emissions data that would allow investors (i.e., investment management firms) to clearly differentiate between “leaders” – enterprises with strong financial underpinnings, sustainable business models, prudent management practices, and a governance structure that supports these objectives – and “laggards”.

Various commenters remind EPA that methane is a GHG and agree that the rule is an important step in identifying sound investments needed to reduce methane emissions – the cheapest and easiest means of reducing the industry's GHG footprint – tackle climate change, and help address public health issues, while also offering economic opportunities – support quality, family-sustaining jobs and a way to meet air quality goals outlined in, for example, the Paris Agreement.

While commenters applaud EPA's effort to strengthen and broaden the NSPS and EGs, most commenters believe that it does not go far enough and call on the EPA to further tighten rules surrounding the release of methane emissions from the oil and natural gas industry. In these cases, commenters often highlight specific areas in the rule where they believe further improvements, or additional clarification are warranted, and offer one or more recommendations aimed at toughening/clarifying EPA's final rule (and its underlying analysis) and maximizing net benefits. Several of the recommendations provided mimic those offered in one or more mass campaign mailer – e.g., strengthen leak monitoring requirements to include low-production wells, transition to zero-emitting technologies for pumps/controllers, ban/limit flaring to only cases of emergency.

A few commenters expressed concern over the health and wellbeing (safety risks) of workers and local communities – vulnerable populations located near oil and gas facilities, which commenters argue are disproportionately impacted. While commenters agree that the proposed updates to the rule could aid in addressing environmental justice issues, they also agree that critical changes to the rule are still needed to address EJ concerns effectively and efficiently – i.e., continue to allow communities the ability to monitor pollution, reduce the timeframe between high level of pollution notification and responses, adequately reward notifiers, and strengthen documentation requirements.

At least one commenter states that they support EPA’s analytical proposal to put the social cost of carbon equivalents (SC-CO<sub>2e</sub>) at \$190/mTon based on extensive research and analysis, and also suggests that this proposed baseline for damage costs is most likely overly conservative due to what they believe are several omissions in EPA’s analysis which probably justify the higher of the three benchmark pricing points of \$340/mTon.

### Oppose

Approximately 16 percent of commenters (including one leasing management company) oppose the proposed rule as written. Technical commenters and remarks covering specific areas of concern vary from commenter to commenter. Some commenters question, in general, the quality (and accuracy) of the data used in developing proposed requirements, and techniques used to accept, reject or qualify data. One commenter (representing a management company) asserts that the supplemental proposal (and its adjourning rule) is based on dated information – pulled from large producers in operations in 1974, and therefore, not valid for current operations, particularly operations of small, marginal producers. The commenter states that ignoring difference between large 1974 operations and 2023 small operations is totally unacceptable and should never be used for proposing new rules, and instead urges the Agency, in finalizing this rule, to utilize recent data generated and made available by the Department of Energy (DOE).

Another commenter maintains that if implemented, the proposed standards will impose real and significant compliance costs in the pursuit of illusory climate benefits. The commenter further states that EPA’s reliance on the Interagency Working Group’s (IWG) deeply flawed social cost of greenhouse gases (SC-GHG) methodology to estimate the proposal’s net benefits renders the entire exercise vulnerable to challenge as arbitrary and capricious, and therefore, should be withdrawn.

One commenter (West Virginia Surface Owner's Rights Organization) (comprised of roughly 800 members) that represents West Virginia’s surface owners expresses concern about limiting inspections to only AVO inspections in some instances. The commenter questions the adequacy of AVO inspections to effectively detect methane leaks and its overall purpose/need considering the availability of lost-cost alternative methane detection technologies – e.g., Amazon results in a wide choice of meters capable of detecting methane appearing starting at a price of only \$32.

## Chapter 2. Legal Basis for Rulemaking

### 2.1 EPA's Statutory Authority under the Clean Air Act

#### *2.1.1 Supplemental Proposal Exceeds EPA's Statutory Authority Under Section 111(d) of the CAA*

Comment: Commenters (2237-NDIC, 2241-UDNR, 2252-PAW, 2254-PBPA, 2292-WV AG et al, 2428-API) contend the supplemental proposal exceeds EPA's statutory authority under the Clean Air Act (CAA). Specific comments are provided in the following paragraphs.

Commenter (2237-NDIC) contends that this EPA proposal to impose a national one-size-fits-all best system of emission reduction (BSER) as the default baseline requirement for state plans violates section 111 of the CAA. The commenter notes that the EPA states that a "state plan needs to include a demonstration that the state requirements for designated facilities achieve the same or greater emissions reduction as the designated facility presumptive standards."<sup>1</sup> EPA's claimed performance for BSER technologies are not just estimates of the costs in tons per year (tpy) of emission reductions but are rather emission reduction targets that EPA demands the states to implement and achieve for each BSER source in order to have an "approvable" state plan. The commenter asserts that such an EPA dictate violates section 111 of the CAA and the cooperative federalism enshrined in the CAA by Congress. The commenter asserts that EPA must withdraw the unlawful supplemental proposal or substantially rework it to remedy this unlawful approach.

Additionally, the commenter (2237-NDIC) provides that EPA is unlawfully imposing a national presumptive emission limitation for all state plans. The commenter contends that EPA's presumptive national emission limitation standards for existing sources deprives states of their authority and discretion to control emissions through state plans and are unlawful under section 111(d) of the CAA. Described as an "experiment in federalism," *Michigan v. EPA*, 268 F.3d 1075, 1078 (D.C. Cir. 2001) (quotation omitted), the CAA assigns to the states the primary sovereign role in air pollution prevention and control. According to the commenter, one of the states' principal authorities and responsibilities under the Act is to implement and enforce standards of performance for existing sources of air pollution under CAA section 111(d), using the states' expertise in applying source-specific considerations and factors to establish achievable emission limitations controlling air emissions from those sources.

Commenter (2237-NDIC) also notes that CAA section 111(d) directs EPA's Administrator to "prescribe regulations which shall establish a procedure ... under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant . . . and (B) provides for the implementation and enforcement of such standards of performance." 42 U.S.C. section 7411(d)(1). The commenter states that this text reflects the federal-state balance of the cooperative federalism framework created by Congress: EPA is to establish national guidelines (i.e., BSER) for the states to follow in creating their CAA section 111(d) plans, and it is the states, through the state plans, that establish the specific

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<sup>1</sup> 87 Fed. Reg. at 74,814.



standards of performance (i.e. achievable emission limitations) for the existing sources in their states. The commenter notes that the primary "regulatory authority" and decisionmaker in setting standards of performance for specific individual existing sources under CAA section 111(d) is therefore the state and CAA section 111(d) does not grant EPA the authority to establish nationwide mandatory emission limitations such as the presumptive and fixed standards of performance masquerading as "BSER" in the supplemental proposal, thereby forcing the states to achieve these emission limitations through the state plans. The commenter states that this deprives states of their authority expressly protected under CAA section 111(d), reducing the states' roles to mere extensions of federal authority.

Furthermore, the commenter (2237-NDIC) asserts that EPA wrongly justifies its unlawful extension of its authority by claiming that in *West Virginia et al. v. EPA*, 142 S. Ct. 2587 (2022) "[t]he Supreme Court made clear that CAA section 111 authorizes the EPA to determine the BSER and the amount of emission limitation that state plans must achieve."<sup>2</sup> In fact, the commenter notes that the Supreme Court in *West Virginia* gave no such blessing for EPA to set a BSER that operates as a presumptive national standard of performance, imposing binding emission limitations on the states:

We have no occasion to decide whether the statutory phrase "system of emission reduction" refers exclusively to measures that improve the pollution performance of individual sources, such that all other actions are ineligible to qualify as the BSER. To be sure, it is pertinent to our analysis that EPA has acted consistent with such a limitation [e.g. only choosing BSER measures that could be applied at individual sources] for the first four decades of the statute's existence. But the only interpretive question before us, and the only one we answer, is more narrow: whether the "best system of emission reduction" identified by EPA in the Clean Power Plan as within the authority granted to the Agency in Section 111 (d) of the Clean Air Act. For the reasons given, the answer is no."<sup>3</sup>

According to the commenter (2237-NDIC), the Supreme Court was clear that the general question the scope of EPA's authority under CAA section 111(d) was not before it, and that the only issue it was deciding was EPA's authority to promulgate the BSER in the Clean Power Plan. The commenter notes that the Supreme Court decided that BSER, which sought to impose one-size-fits-all national emission standards on the states, was unlawful and that EPA's claim in this supplemental proposal is incorrect. The commenter also contends that EPA's "position that CAA section 111(d) authorizes the EPA to allow states, in particular rules, to achieve the requisite emission limitation through the aggregate reductions from their sources, and the EPA is accordingly proposing to authorize states to leverage their state programs to satisfy their CAA section 111(d) state plan obligations pursuant to emission guidelines (EG) OOOOc, subject to requirements discussed in the following sections,"<sup>4</sup> is incorrect for several reasons. First, the commenter states EPA must select BSER that can be applied at the source, and not on an aggregate level. Second, the commenter notes that under the cooperative federalism framework of the CAA, EPA is not authorized under section 111(d) to set national emission limitations for

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<sup>2</sup> 87 Fed. Reg. at 74,812.

<sup>3</sup> 142 S. Ct. at 2615-2616.

<sup>4</sup> 87 Fed. Reg. 74,813.

existing sources. Instead, EPA sets the BSER, based on a technology applicable at a particular existing source, and then the states create their own respective CAA section 111(d) plans with source-specific emissions limitations that the states establish using the BSER guidelines selected by EPA.

Under CAA section 111(d)(1), the commenter (2237-NDIC) asserts EPA does not have the authority to establish and impose presumptive national emission limitations for existing sources, with the sole remaining role of the states being the requirement to implement the national standards through local rules. According to the commenter, EPA is only authorized to "establish a procedure" (42 U.S.C. section 7411(d)(1)) for states to follow when they create state plans containing performance standards established by states applying EPA's BSER. The commenter adds that the EPA's BSER are only to be guidelines (see the title of the supplemental proposal, characterizing the proposed rule as creating "Emission Guidelines for Existing Sources" 87 Fed. Reg. at 74,702), not binding overarching national emission standards for the states or existing sources. According to the commenter, section 111(d) of the CAA is explicit that it is the states, not EPA, that establish the binding standards of performance for existing sources.

Finally, the commenter (2237-NDIC) concludes that EPA's proposed BSER technologies intended as presumptive national binding emission limitations for existing sources exceed EPA's authority under the CAA and deprive states of their authorities protected by the CAA. The commenter argues that EPA must withdraw these presumptive overreaching national standards and instead propose BSER technology guidelines, from which the states can then adroitly create CAA section 111(d) plans for existing sources that set the actual and better tailored localized standards of performance and required emission limitations.

Commenter (2241-UDNR) provides that in the immediate wake of the Supreme Court's decision in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), the EPA's obligation to identify clear, express statutory authority for rulemaking is heightened.<sup>5</sup> In *West Virginia*, the EPA's rulemaking authority under the sections 111(b) and (d) of the CAA came under scrutiny. It is precisely these same sections that the EPA relies on to promulgate the proposed rule and supplemental proposal that are the subject of this current comment letter. In *West Virginia*, the Supreme Court found that the EPA's Clean Power Plan had exceeded their authority, and "had applied too broad an interpretation of 'best system of emission reduction.'"<sup>6</sup> In light of this holding, the commenter encourages the EPA to review the November 2021 proposed rule and December 2022 supplemental proposal to ensure that the current rulemaking process does not also apply too broad an interpretation of "best system of emission reduction" and/or exceed its statutory rulemaking authority under the CAA.

Commenter (2252-PAW) asserts that EPA is overstepping Congress's authority granted to states through the CAA to develop a compliance program for existing sources. The commenter states

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<sup>5</sup> Tina Van Bockern, Here We Go Again: BLM Issues Another Methane Rule, Holland & Hart, available at: <https://www.hollandhart.com/here-we-go-again-blm-issues-another-methane-rule> (2022); citing *Wyoming v. U.S. DOI*, 493 F. Supp. 3d 1046 (D. Wyo. 2020).

<sup>6</sup> Grace Olson, Understanding the US Supreme Court's Decision in *West Virginia v. EPA*, Great Plains Institute, available at: <https://betterenergy.org/blog/understanding-the-us-supreme-courts-decision-in-west-virginia-v-epa/> (2022).

that the resulting December 2022 proposal imposes \$2.8 billion in annual compliance costs to the oil and gas industry, with most of these costs being borne on existing facilities. The commenter states that this is because the EPA is proposing that the emission controls it will require of new oil and gas facilities are also cost-effective for existing sources, which should instead tier off the EPA's requirements for new sources.

The commenter (2292-WV AG et al) adds that the proposed "presumptive" standards are presumptuous. The commenter asserts that CAA empowers states, not the agency, to create their own implementation plans to reduce methane emissions from existing sources under EPA's supervision. This flexibility includes the right to "establish[] standards of performance for designated facilities" reflecting the EPA-derived emission limits that are achievable through the BSER. The commenter asserts that EPA is trying to squash state agency discretion by channeling it into EPA-drafted "presumptive" plans.

Commenter (2254-PBPA) contends that neither Congress nor (until recently) EPA envisioned CAA section 111(d) being used, as here, to regulate whole sectors of the economy. When EPA first established procedures and requirements for submittal of state plans for control of pollutants from existing facilities under CAA section 111(d), the commenter notes that the EPA stated that under CAA section 111(d) "extensive control strategies are not required," State plans would "be much less complex," and "the number of designated facilities per State should be few." Indeed, the commenter adds that the EPA has only rarely promulgated CAA section 111(d) standards and only for industry-specific pollution issues like acid mist emissions from sulfuric acid plants. According to the commenter, the EPA's infrequent and narrow use of CAA section 111(d) confirms that this provision was understood to allow limited regulation of existing sources and that the provision was a secondary part of the overall statutory scheme. The commenter states that this also applies to the EPA's remaining useful life and other factors (RULOF) proposal, which they believe inappropriately constrains states in contravention of EPA's prior practice and the flexibility Congress provided in CAA section 111(d). The commenter asserts that this goes too far, and EPA has failed to adequately explain or justify its departure from prior practice.

Response II-2-1: The commenters raise a series of issues related to EPA's authority to establish the BSER for existing sources. These comments lack merit. First, the commenters argue that EPA's determination of the BSER for emission sources improperly sets nationwide mandatory emission limits for these sources. Contrary to commenter's assertions, EPA's emission guidelines do not include a prescriptive "one-size-fits-all" BSER analysis. Rather, the emission guidelines are based on aggregate information that represents what EPA believes to be the BSER for an "average" existing source, taking into account the statutory criteria in section 111. EPA agrees with the commenters assertion that the CAA allows state to set standards of performance for existing sources. However, EPA also has a role to play in that process. Under EPA's longstanding regulations in subpart Ba (and the predecessor subpart B), along with the newly promulgated revisions to subpart Ba, EPA's emission guidelines include information to assist states with developing their standards of performance, including the degree of emission limitation achievable through application of that BSER. A fuller discussion of the role of EPA in identifying the BSER, and of the role of States in establishing standards of performance for existing sources is including in the record for the separately finalized Subpart Ba rulemaking.

The comments addressing the Subpart Ba rulemaking are addressed in the record for that rulemaking.

Next, the commenters contend that EPA lacks authority to determine what emission limitations are achievable by existing sources, and that EPA's determination of the BSER usurps the role of the States. That is incorrect. Unless EPA specifies "the degree of emission limitation achievable through application of" the BSER, under section 111(a)(1), States would lack meaningful guidance on what plans EPA would find "satisfactory," section 111(d)(2)(A). EPA's regulations therefore require the agency to specify the degree of emission limitation achievable. 40 C.F.R. 60.22a(b)(5). The Supreme Court's decision in *West Virginia* is consistent with the EPA's understanding. For a discussion of the factors that the EPA considered in establishing the BSER and degree of emission limitation for existing sources in the EG, as well as the states' role in establishing standards of performance implementing this EG (including the authority to establish less stringent standards), see section XIII of the preamble for this final rule.

Lastly, the EPA recognizes that it has promulgated fewer emission guideline rules than New Source Performance Standards. This does not undermine the EPA's authority to establish the emission guidelines here. The EPA's authority to establish emission guidelines for this source category is discussed at length in section IV of the preamble for this rule.

### ***2.1.2 EPA Does Not Have Authority to Modify the CAA***

Comment: Commenters (2200-NuEnergy, 2257-MOGA) question the authority of EPA to make modifications to the CAA without congressional approval.

Commenter (2200-NuEnergy) states that the CAA was originally written and authorized by the federal government through the House of Representatives and approved by the Senate in the early 1970's. The commenter contends that revisions, additions, and changes that have been authored and approved solely by the EPA without elected congressional input or voting for approval is likely illegal. According to the commenter, this does not allow the people of the U.S. to have a voice and questions whether EPA is only listening to non-governmental organizations (NGOs) to create regulations.

Commenter (2257-MOGA) refers to a previous request that they made to EPA to provide clarification of the validity of arguments made by the EPA in the "2020 Methane Rollback Rule" published in the *Federal Register* regarding the ability of the EPA to regulate methane under the CAA based on the premise that Methane was not listed as a known chemical detrimental to human health and the environment. The commenter inquired at that time whether Congressional modification to the CAA was necessary to add methane to the CAA. Since the EPA referenced the Methane Rollback regulations in the December 6, 2022, proposed regulations, the commenter believes that the EPA provided argument to the validity to the Methane Rollback rule and should provide explanation as to why EPA now believes it has legal authority to regulate methane without Congressional modification to the CAA. According to the commenter, without Congressional approval from both the Federal House of Representatives and the U.S. Senate, additions, removals, or edits to the CAA are not considered binding. Also, the commenter is requesting clarification from the EPA regarding the permissible time allotments between any rule

changes to the CAA. The commenter notes that review of the 1970 rule suggests significant modifications to the rule may not be more frequent than 7-year cycles without Congressional approvals.

Response II-2-2: As the EPA explained in the 2016 rule, CAA section 111 authorizes the EPA to regulate GHG emissions, including methane, from the oil and gas source category after determining that it is rational to do so or, in the alternative, after making a GHG-specific significant contribution finding. The EPA made those findings and therefore is authorized to regulate GHG emissions in the form of methane from the oil and gas source category. The 2016 rule and this action are fully consistent with CAA section 111, for the reasons explained in the preamble and in the various chapters of this Response to Comment document. The EPA has received input and comments from numerous entities, including industry and states, and has responded to those comments.

### ***2.1.3 Proposals are Consistent with West Virginia v. EPA Court Decision***

Comment: Commenter (2433-EDF et al) addresses the impact of the Supreme Court’s June 2022 decision in *West Virginia v. EPA*.<sup>7</sup> In that case, the Court considered EPA’s authority under CAA section 111(d) to establish CO<sub>2</sub> EGs for existing fossil fuel-fired power plants. Specifically, the Court held that in designating the “best system of emission reduction” for such sources, EPA lacked authority to include emission reduction measures based on generating-shifting—that is, measures reflecting the opportunity for grid-level shifts away from existing fossil-fired electricity generation like coal and gas plants and toward new renewable energy like wind and solar generators.<sup>8</sup> According to the Court, a generation-shifting approach for the electric power sector entailed a “transformative expansion” of its section 111(d) authority<sup>9</sup> and effected a “fundamental revision of the statute.”<sup>10</sup> Thus, under the “major questions doctrine,” a section 111(d) rule based on generation-shifting required explicit authorization in the CAA, which the Court found lacking.<sup>11</sup>

According to the commenter (2433-EDF et al) the NSPS OOOOb and EG OOOOc proposals are fully consistent with the Court’s decision in *West Virginia*. In reaching its decision, the court contrasted generation-shifting—which reduces the emissions of the “overall power system” by requiring dirtier sources to operate less often in favor of cleaner, non-regulated sources—with traditional “technology-based” CAA section 111 standards, which focus “on improving the emissions performance of individual sources.”<sup>12</sup> The commenter states that EPA’s proposed NSPS OOOOb and EG OOOOc rules fall squarely within the latter category: they achieve pollution reductions entirely through the use of source-based technologies that improve the emissions performance of individual pieces of equipment. Furthermore, the Court in *West Virginia* deployed an interpretive principle—the major questions doctrine—that is reserved for “extraordinary cases ” involving agency actions that, among other unusual characteristics, reflect

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<sup>7</sup> *West Virginia v. EPA*, 142 S. Ct. 2587 (2022).

<sup>8</sup> *Id.*

<sup>9</sup> *Id.* at 2610.

<sup>10</sup> *Id.* at 2612.

<sup>11</sup> *Id.* at 2614–16.

<sup>12</sup> *Id.* at 2611.

a “transformative expansion [of the agency’s] regulatory authority” and that are purported to have “vast economic and political significance” for the country.<sup>13</sup> The commenter adds that the NSPS OOOOb and EG OOOOc rules reflect the use of readily available technology options that many oil and gas operators already use and support, will allow companies to defray costs and even earn profits in some instances through sale of captured gas, and will have an effectively negligible impact on consumer energy spending. The commenter contends that this is exactly the kind of “ordinary” regulation that simply does not implicate the concerns at issue in *West Virginia*.<sup>14</sup>

Additionally, the commenter (2433-EDF et al.) states that *West Virginia*’s holding confirms EPA’s regulatory authority in one important respect. In particular, the commenter notes that the state of North Dakota previously argued that EPA’s role under CAA section 111(d) was merely an advisory one, and that states, not EPA, were primarily responsible for determining the substantive emission reduction requirements to be achieved by existing sources.<sup>15</sup> The commenter rebutted this position in their comments on the 2021 proposal,<sup>16</sup> and the Supreme Court definitively foreclosed it in *West Virginia*. Even while it ruled against EPA in that case, the Court explained that “[a]lthough the States set the actual rules governing existing [sources], EPA itself still retains the primary regulatory role in Section 111(d)” and “[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved.”<sup>17</sup> Accordingly, state plans under CAA section 111(d) are “*not to exceed the permissible level of pollution established by EPA*.”<sup>18</sup> The commenter believes that the agency is thus acting firmly within the scope of its authority by issuing EGs for oil and gas methane emissions that establish binding emission reduction requirements to which state plans must adhere.

Response II-2-3: The EPA agrees with the commenters that this rulemaking is consistent with the Supreme Court’s decision in *West Virginia*.

### ***2.1.4 EPA Has the Authority Under the CAA to Establish State Plan Requirements***

Comment: Commenter (2355-Constellation Energy) asserts that EPA has the authority under the CAA to establish minimum requirements, approve state plans that are more stringent than EGs, and allow trading and averaging in state plans. The commenter provides justification for their assertions in the following paragraphs.

Firstly, the commenter (2355-Constellation Energy) agrees with EPA’s interpretation of CAA section 111(d) that the Agency must determine the “degree of emission limitation achievable” by existing sources through application of the BSER and then must translate the degree of emission limitation achievable into minimum standards of performance that states may use in their state

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<sup>13</sup> Id. at 2608, 2610, 2605.

<sup>14</sup> Id. at 2608.

<sup>15</sup> State of North Dakota, Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 7–10 (Jan. 31, 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-0797), [https://downloads.regulations.gov/EPA-HQ-OAR-2021-0317-0797/attachment\\_1.pdf](https://downloads.regulations.gov/EPA-HQ-OAR-2021-0317-0797/attachment_1.pdf).

<sup>16</sup> See 2022 Joint Environmental Comments, at 211–14.

<sup>17</sup> *West Virginia*, 142 S. Ct. at 2601–02.

<sup>18</sup> Id. at 2602 (emphasis added).

plans. The commenter states that any EGs developed under CAA section 111(d) should establish minimum requirements that are binding, sufficiently stringent, and comply with the statute.

The commenter (2355-Constellation Energy) notes that section 111(d)(1) of the CAA directs EPA to establish a procedure similar to section 110 of the Act for states to submit plans that establish “standards of performance” for air pollutants that are not regulated under section 112 and for which no national ambient air quality standard has been established under section 108(a), from existing sources which would be subject to standards of performance under section 111(b) if they were new sources.<sup>19</sup>

The commenter (2355-Constellation Energy) asserts that this statutory structure contemplates a complementary regulatory approach in which both EPA and the states have a role.

The commenter (2355-Constellation Energy) suggests that the most logical interpretation of CAA section 111(d)(1) when read with the definition of “standard of performance” in CAA section 111(a) is that EPA must determine the “degree of emission limitation achievable” through application of the BSER. “Standard of performance” is defined as:

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.<sup>20</sup>

The commenter (2355-Constellation Energy) believes that the natural reading of this definition supports the conclusion that the “Administrator determines” both the “best system of emission reduction” and the “degree of emission limitation achievable” through that system of emission reduction. This interpretation also would avoid the anomalous result of interpreting or applying the same defined term—“standard of performance”—differently for purposes of CAA section 111(b) and CAA section 111(d)(1). The commenter agrees that CAA section 111(b) directs EPA to establish standards of performance for new sources in listed source categories and does not expressly contemplate a role for states in establishing those standards, whereas CAA section 111(d) directs EPA to develop a procedure for states to submit plans that establish standards of performance. But in both cases, the commenter notes that the statute requires the development of “standards of performance” as defined in CAA section 111(a)(1), and it makes sense for EPA to apply the same interpretation of the definition of “standard of performance” in CAA section 111(d) as in CAA section 111(b).

The commenter (2355-Constellation Energy) reports that the U.S. Supreme Court endorsed this approach as recently as last year, explaining that “ The Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. . . . The States then submit plans containing the emission restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.”<sup>21</sup> The commenter asserts that this

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<sup>19</sup> 42 U.S.C. § 7411(d)(1).

<sup>20</sup> 42 U.S.C. § 7411(a)(1).

<sup>21</sup> *West Virginia v. EPA*, 142 S. Ct. 2587, 2601–02 (2022).

approach is also consistent with EPA’s previous rulemakings under section 111(d)(1), and with EPA’s general regulations that were in place for more than 40 years.<sup>22</sup> Nothing suggests the Agency has erred for more than four decades in its understanding of the respective roles of EPA and the states in implementing section 111(d)(1).

In the EGs in the December 2022 supplemental proposal, the commenter (2355-Constellation Energy) notes that EPA proposes to translate the degree of emission limitation achievable through application of the BSER into presumptive standards for specific designated facilities. If a state chooses to adopt the presumptive standards as the standards of performance in a state plan and the plan meets all other applicable requirements, EPA would approve the plan as meeting the requirements of CAA section 111(d) and the EGs. The commenter agrees with this approach and suggests EPA finalize presumptive standards for all designated facilities.

The commenter (2355-Constellation Energy) believes that including presumptive standards of performance that represent a minimum level of control in the EGs is critical to the meaningful success of a GHG regulatory regime. This approach would create administrable criteria against which EPA can measure the adequacy of a state plan. The commenter reports that the statute expressly directs EPA to establish a procedure similar to CAA section 110 for the submission and review of state plans, and thus assigns to EPA the responsibility to approve or disapprove state plan submissions. Where the state has failed to submit an approvable plan, the statute mandates that EPA develop one.<sup>23</sup> The commenter states that EPA has long recognized that this approach makes sense only if “Congress intended the [s]tates to prescribe standards on some substantive basis” and intended that substantive criteria—not just procedural criteria—govern EPA’s review of state plans.<sup>24</sup> The commenter asserts that in the absence of any EPA-developed minimum standards, EPA would be unable to review state plans against reasonable, substantive criteria.

The commenter (2355-Constellation Energy) contends that providing minimum standards also substantially eases the administrative burdens on states. Without minimum standards, the state would have to translate, for each affected facility, the degree of emission limitation achievable into a standard of performance, taking into account source-specific features. The commenter believes that where EPA provides presumptive standards, it is less time-consuming and resource intensive for states to develop their plans, submit their plans for review and approval more quickly, and enabling faster implementation of pollution reduction measure.

In addition, the commenter (2355-Constellation Energy) states that providing minimum standards that, if included in a state plan would render the plan presumptively approvable, also provides affected facilities with greater certainty of what will be required. Certainty is necessary

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<sup>22</sup> Since 1975, when EPA promulgated general regulations governing the establishment of standards under section 111(d) and state plans, EPA has interpreted section 111(d) to require the Agency to set minimum substantive requirements for state performance standards. *State Plans for the Control of Certain Pollutants From Existing Facilities*, 40 Fed. Reg. 53,340, 53,342–343 (Nov. 17, 1975). Indeed, that is the approach EPA has taken every time it has regulated under section 111(d). See 82 Fed. Reg. 65,507, 61,512 n.11 (Dec. 28, 2017) (listing section 111(d) emission guidelines for other categories of sources).

<sup>23</sup> 42 U.S.C. § 7411(d)(2).

<sup>24</sup> *State Plans for the Control of Certain Pollutants From Existing Facilities*, 40 Fed. Reg. at 53,342.



for facilities to plan for investment that achieves the emission reduction goals of the regulation.

Secondly, the commenter (2355-Constellation Energy) agrees that EPA has the authority to approve state plans that are more stringent than required by the EGs, and to render the state plan federally enforceable. The commenter notes that state authority to address air pollution extends to include measures that are not inconsistent with or less stringent than federal law.<sup>25</sup>

Cooperative federalism principles in the CAA demand that EPA protect states' authority to establish requirements and to pursue reductions that exceed minimum federal standards, allowing states to achieve their own goals and initiatives to address air pollution. The commenter reports that the CAA carves out a critical role for states to address air pollution,<sup>26</sup> and the Act does not preempt state authority to exceed the minimum requirements established by the statute or by EPA in regulations promulgated under the statute. The commenter asserts that an interpretation of the Act, including CAA section 116, that EPA does not have discretion to approve state plans that are more stringent than required by the Emissions Guidelines would unlawfully strip states of their authority to establish air pollution measures that exceed minimum federal standards. Once EPA approves such a state plan, the state plan becomes federally enforceable by operation of CAA section 111(d).<sup>27</sup>

Thirdly, the commenter (2355-Constellation Energy) believes that EPA has the authority to allow trading and averaging in state plans. The commenter reports that trading and averaging are familiar mechanisms employed by EPA and states in a variety of programs as powerful tools to achieve cost-effective and meaningful air pollution reductions. The commenter has long supported such market-based programs as enabling an industry to achieve meaningful emission reductions at lower overall cost.

In the December 2022 supplemental proposal, the commenter (2355-Constellation Energy) states that the EPA interprets the CAA to allow the Agency to permit states to include trading and averaging in their plans where permitted by EPA in sector-specific CAA 111(d) EGs. The commenter notes that EPA adopted a more restrictive interpretation in the Affordable Clean Energy rule (ACE Rule)<sup>28</sup> that the U.S. Court of Appeals for the District of Columbia found was inconsistent with the Act.<sup>29</sup> That portion of the D.C. Circuit's decision in *American Lung Association v. EPA* was not disturbed by the U.S. Supreme Court's decision in *West Virginia v. EPA*.<sup>30</sup> The commenter reports that the only question before the Supreme Court was: "whether the 'best system of emission reduction' identified by EPA in the Clean Power Plan was within the authority granted to the Agency in Section 111(d) of the Clean Air Act."<sup>31</sup> In the Clean Power Plan, EPA determined that "generation shifting" is considered part of the "best system of emission reduction" for power plants, and used that "system" to determine "the degree of

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<sup>25</sup> 42 U.S.C. § 7416 (retention of state authority).

<sup>26</sup> See, e.g., 42 U.S.C. § 7407(a) (providing that states have "primary responsibility for assuring air quality" within the geographic area comprising the state by submitting implementation plans to achieve and maintain national ambient air quality standards).

<sup>27</sup> 42 U.S.C. § 7411(d)(2).

<sup>28</sup> Repeal of Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Generating Units; Revisions to Emission Guidelines Implementing Regulations, 84 Fed. Reg. 32,520 (July 8, 2019).

<sup>29</sup> *American Lung Ass'n v. EPA*, 985 F.3d 914, 957–58 (D.C. Cir. 2021).

<sup>30</sup> *West Virginia*, 142 S. Ct. at 2614-15.

<sup>31</sup> *Id.* at 2615-16.

emission limitation achievable through the application” of that system. The *West Virginia* decision applied the major question doctrine to conclude that EPA did not have legal authority to “set an emissions cap at the level ‘which reflects the degree of emission limitation achievable through the application of [a cap-and-trade] system[.]’”<sup>32</sup> Notably, what the U.S. Supreme Court did not do is impair EPA’s ability to authorize states to develop section 111(d) state plans that include cap-and-trade systems for sources to comply with standards of performance established under those plans.<sup>33</sup> In other words, while the *West Virginia* decision may preclude EPA from using the generation shifting that results from a cap-and-trade system to derive the standards of performance, the commenter contends that the decision does not preclude EPA from allowing state cap-and-trade programs as a means of complying with standards of performance.<sup>34</sup>

Though the statute provides EPA with authority to allow trading in state plans, the commenter (2355-Constellation Energy) suggests that a state plan that integrates trading will not necessarily meet the requirements for environmental equivalence with a CAA section 111(d) EG. Where EPA exercises its discretion to permit trading, the Agency must do so in a manner that will result in standards of performance that will yield the necessary aggregate emission reductions from the units covered by the state plan. This should be an obvious and uncontroversial point. By expressly requiring that a standard of performance reflect “the degree of *emission limitation*” achievable through the “best system of *emission reduction*,” the definition of “standard of performance” unambiguously requires that such standards actually result in emission reductions.<sup>35</sup> This plain language interpretation, according to the commenter, is consistent with the overall purpose of the Act: to promote “pollution prevention,” i.e., “the reduction or elimination . . . of the amount of pollutants produced or created at the source.”<sup>36</sup> Therefore, any emission guidelines established under CAA section 111(d) and any state plan developed pursuant thereto must ensure that standards of performance actually compel covered sources to reduce their emissions in the aggregate, and that any compliance mechanisms using trading or averaging are appropriately designed to achieve that result.

Response II-2-4: The EPA generally agrees that the EPA has authority to establish minimum requirements for state plans, approve state plans that are more stringent than the emission guidelines, and that trading and averaging may be appropriate as part of state plans. The EPA notes that we have finalized the Agency’s interpretations regarding the states’ ability to establish more stringent standards and the authority to rely on trading in averaging in the separately finalized subpart Ba rulemaking. A detailed discussion of States’ role in the state plan process is included in the preamble, and discussed at further length in the Subpart Ba rule.

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<sup>32</sup> Id. at 2615 (alteration original).

<sup>33</sup> See id. at 2615 (“But just because a cap-and-trade ‘system’ can be used to reduce emissions does not mean that it is the kind of ‘system of emission reduction’ referred to in Section 111.”).

<sup>34</sup> See id. (“It is one thing for Congress to authorize regulated sources to use trading to comply with a preset cap, or a cap that must be based on some scientific, objective criterion, such as the NAAQS. It is quite another to simply authorize EPA to set the cap itself wherever the Agency sees fit.”).

<sup>35</sup> See 42 U.S.C. § 7411(a)(1) (emphasis added).

<sup>36</sup> 42 U.S.C. § 7401(a)(3), (c).

### 2.1.5 Regulation of Methane Under the CAA

Comment: Commenters (2355-Constellation Energy, 2410-CA AG et al, 2433-EDF et al) state that EPA has the authority, and in some cases the obligation, to regulate methane under the CAA.

Commenter (2355-Constellation Energy) believes that the EPA's duty to regulate greenhouse gas (GHG) emissions from the Crude Oil and Natural Gas source category is well-established and that EPA is correct not to reopen its conclusion from the 2016 Oil and Natural Gas Sector rule (2016 Rule)<sup>37</sup> that the Agency is not required to make an additional pollutant-specific finding that GHG emissions from the source category contribute significantly to dangerous air pollution.

The commenter (2355-Constellation Energy) states that the Supreme Court confirmed that GHGs are air pollutants under the CAA.<sup>38</sup> Thereafter, in 2009, EPA made an endangerment finding under section 202(a)(1) of the Act, confirming through "a large body of robust and compelling scientific evidence"<sup>39</sup> that the level of GHGs in the atmosphere may reasonably be anticipated to endanger human health and the environment.<sup>40</sup> The endangerment finding and EPA's regulation of greenhouse gas emissions from mobile sources has been upheld in court.<sup>41</sup> The commenter contends that strong scientific evidence linking anthropogenic GHG emissions to threats to human health, welfare, and the environment has only grown stronger since this finding and remains irrefutable.<sup>42</sup> Thus, the commenter provides that there is no reasonable dispute at this point that EPA can and must regulate GHG emissions under the CAA, an obligation confirmed by the Supreme Court in 2011.<sup>43</sup>

Additionally, the commenter (2355-Constellation Energy) asserts that methane must be addressed in regulatory programs addressing the oil and gas sector, and that EPA's first meaningful step to this end was in 2016 when it promulgated a rule regulating emissions of greenhouse gases (in the form of limitations on methane emissions) from new, modified, and reconstructed sources in the production, processing, transmission, and storage segments. The commenter notes that, as EPA properly recognized at the time, a new endangerment finding was not a prerequisite to that regulation. The commenter contends that section 111 of the Act does not require a separate endangerment finding when EPA establishes standards of performance

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<sup>37</sup> Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824 (June 3, 2016).

<sup>38</sup> *Massachusetts v. EPA*, 549 U.S. 497, 528–29 (2007).

<sup>39</sup> Carbon Pollution Emissions Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,682 (Oct. 23, 2015).

<sup>40</sup> Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,497 (Dec. 15, 2009).

<sup>41</sup> *Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 117 (D.C. Cir. 2012); see also *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 314 (2014).

<sup>42</sup> See, e.g., United Nations Environment Programme and Climate and Clean Air Coalition, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions (2021), <https://www.ccacoalition.org/en/resources/global-methane-assessment-full-report>; <https://www.science.org/doi/10.1126/science.aat5982>; Philip B. Duffy et al., Strengthened Scientific Support for the Endangerment Finding for Atmospheric Greenhouse Gases, *Science* (2019), <https://www.science.org/doi/10.1126/science.aat5982>.

<sup>43</sup> *American Electric Power Co. v. Connecticut*, 564 U.S. 410, 424 (2011).

for emissions of a pollutant for which EPA already made an endangerment finding, from a source category already listed under section 111.<sup>44</sup>

Commenter (2355-Constellation Energy) points out that EPA listed the Crude Oil and Natural Gas Production source category for regulation under CAA section 111 in 1979.<sup>45</sup> By virtue of that listing, the commenter states that the EPA determined that the source category “causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,” pursuant to CAA section 111(b)(1)(A). This “endangerment finding” included both the “causes or contributes significantly” component and the “endanger public health or welfare” component of the determination. In subsequent rulemakings, for which the period available for judicial review has long since passed, EPA refined the scope of this source category.<sup>46</sup> For example, in 2012, EPA established NSPS for VOC emissions from numerous emission sources in the production, processing, transmission, and storage segments of the oil and gas sector.<sup>47</sup> Additional sources in those segments were included in the 2016 Rule.<sup>48</sup> The commenter notes that the 2016 Rule also added standards for GHG emissions—in the form of methane standards—for those sources. The commenter asserts that EPA did not, and was not, required to make a new endangerment finding regarding the Oil and Natural Gas Sector to establish standards of performance for GHG emissions from those sources.

Furthermore, the commenter (2355-Constellation Energy) reports that CAA section 111(b)(1)(B) does not specify what pollutants should be the subject of standards from a source category once the source category is listed for regulation.<sup>49</sup> In the 2016 Rule, EPA applied its well-settled rational basis test: EPA may exercise its discretion to regulate particular pollutants under CAA section 111(b) as long as EPA provides a rational basis for doing so.<sup>50</sup> EPA had then—and continues to have now—a rational basis for regulating greenhouse gas emissions from these sources. In fact, the commenter states that the scientific support forming EPA’s rational basis has only gotten stronger since the 2016 Rule. As noted above, the commenter believes that EPA has ample evidence that GHG emissions cause or contribute to air pollution that is reasonably

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<sup>44</sup> Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,510, 64,529–532 (Oct. 23, 2015); see also *American Electric Power Co.*, 564 U.S. at 426–27 (“[T]he Clean Air Act directs EPA to establish emissions standards for categories of stationary sources that, ‘in [the Administrator’s] judgment,’ ‘caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.’ §7411(b)(1)(A).”) (alterations original).

<sup>45</sup> Priority List and Additions to the List of Categories for Stationary Sources, 44 Fed. Reg. 49,222, 49,226 (Aug. 21, 1979).

<sup>46</sup> See Standards of Performance for New Stationary Sources; Equipment Leaks of VOC From Onshore Natural Gas Processing Plants, 50 Fed. Reg. 26,122 (June 24, 1985) (establishing NSPS for VOC emission from equipment leaks at onshore natural gas processing plants); Standards of Performance for New Stations Sources; Onshore Natural Gas Processing SO<sub>2</sub> Emissions, 50 Fed. Reg. 40,158 (Oct. 1, 1985) (establishing NSPS for SO<sub>2</sub> emissions from onshore natural gas processing plants).

<sup>47</sup> Oil and Natural Gas Sector: New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants Review, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

<sup>48</sup> Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824 (June 3, 2016).

<sup>49</sup> 42 U.S.C. § 7411(b)(1)(B).

<sup>50</sup> 2016 Rule, 81 Fed. Reg. at 35,842.

anticipated to endanger public health and the environment, and this determination has been upheld against legal challenge.

According to the commenter (2355-Constellation Energy), once EPA established standards of performance for new sources under CAA section 111(b), the Agency was legally obligated to establish EGs under CAA section 111(d)(1) for existing sources that would be subject to the new source standards if they were new.<sup>51</sup> In turn, the EGs must require states to promulgate standards of performance for the existing sources.<sup>52</sup> Methane emissions from new, modified, and reconstructed sources in the Crude Oil and Natural Gas source category, including in the production, processing, transmission, and storage segments, have been regulated under section 111 of the CAA since 2016. The commenter contends that EPA has had a duty to develop EGs for methane emissions from existing sources in those segments that would be subject to the new source standards if they were new for the past seven years. The commenter applauds the Agency for initiating that regulation with the November 2021 original proposal and continuing it with the December 2022 supplemental proposal and encourages the Agency to proceed swiftly to promulgate final EGs.

Commenter (2355-Constellation Energy) asserts that state regulation of methane emissions and voluntary methane emission reduction programs and measures are not enough to address the increasingly dangerous impacts of climate change on public health and welfare. While some states have their own regulations for methane emissions at existing oil and gas sources, these regulations vary widely in terms of sources covered, emissions limits, testing frequency, and flexibility to use new leak detection and repair technologies.<sup>53</sup> The commenter agrees with EPA that direct federal regulation of methane from new sources combined with the approved state plans that are consistent with the EGs for existing sources is necessary. The commenter believes that doing so will “level the regulatory playing field, help promote technological innovation, and reduce both climate- and other health-harming pollution from a large number of sources that are either currently unregulated or where additional cost-effective reductions can be obtained.”<sup>54</sup>

Commenter (2410-CA AG et al) similarly states that the oil and natural gas sector contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare and EPA remains statutorily obligated under CAA section 111 to regulate emissions—including methane emissions—from new and existing sources in the oil and natural gas source category. Further, the commenter contends that in 2016, EPA correctly determined that it had legal authority to regulate methane from the oil and natural gas source category under CAA section 111(b)(1)(B).<sup>55</sup> The commenter notes that EPA relied on overwhelming record evidence regarding the adverse impacts of methane to public health and welfare and the high quantities of

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<sup>51</sup> See 42 U.S.C. §7411(d)(1).

<sup>52</sup> *Id.*

<sup>53</sup> See, e.g., U.S. Environmental Protection Agency, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 6-5; 7-4; 9-6 through 9-7; 11-4 through 11-5; 12-5 through 12-6 (Oct. 2021), <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0166>.

<sup>54</sup> Original Proposal, 86 Fed. Reg. at 63,137.

<sup>55</sup> 81 Fed. Reg. at 35,841; *id.* at 35,842–43 (“When considered in total, the facts presented in . . . this preamble, along with prior EPA analysis, . . . provide a rational basis for regulating GHG emissions from affected oil and gas sources by expressing GHG limitations in the form of limits on methane emissions.”).

methane emissions from the oil and natural gas source category, including existing sources.<sup>56</sup> The commenter adds that EPA explicitly made an endangerment and significant contribution finding with respect to GHG emissions from the oil and natural gas source category. Thus, EPA properly concluded that methane emissions must be directly addressed through standards of performance under CAA section 111(b)(1).<sup>57</sup> And since at least 2016, when EPA began to regulate methane from new oil and natural gas sources under section 111(b) of the CAA, EPA has been required to promulgate EGs to regulate methane from existing oil and natural gas sources under section 111(d) of the CAA.<sup>58</sup>

Commenter (2433-EDF et al.) also provides that EPA’s authority under the Clean Air Act to establish source-based technology requirements for individual pieces of equipment, and thus achieve these reductions, is clear. The commenter notes EPA’s authority and obligation to regulate methane from this source category have only been bolstered by Congress through the passage of two items: the Congressional Review Act (CRA) resolution on June 30, 2021, to Disapprove EPA’s Oil and Gas Policy Rule<sup>59</sup> and the passage of the Inflation Reduction Act (IRA), including the Methane Emissions Reduction Program (MERP), on August 16, 2022.<sup>60</sup>

Response II-2-5: The EPA explained its authority to regulate methane emissions in the preamble and in Volume I, Chapter 3 of the RTC. These comments are generally consistent with those explanations, and no further response is necessary.

Comment: Commenter (2254-PBPA) states that as a predicate to promulgating an NSPS, Congress directs EPA to find that a source category “contributes significantly” to air pollution which may reasonably be anticipated to endanger public health or welfare before promulgating

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<sup>56</sup> See, e.g., 81 Fed. Reg. at 35,833–43 (citing to, among other things, EPA’s 2009 endangerment finding for GHGs, including methane, 74 Fed. Reg. 66,496 (Dec. 15, 2009), and subsequent assessments validating and lending additional credence to such finding; the fact that the oil and natural gas source category is the largest industrial emitter of methane in the United States; and the high global warming potential of methane, which is 28 to 36 times greater than that of carbon dioxide); cf. *Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 120 (D.C. Cir. 2012) (“The body of scientific evidence marshaled by EPA in support of the [2009] Endangerment Finding is substantial.”).

<sup>57</sup> 81 Fed. Reg. at 35,833–43.

<sup>58</sup> 81 Fed. Reg. at 35,833–43.

<sup>59</sup> Joint resolution providing for congressional disapproval under chapter 8 of title 5, United States Code, of the rule submitted by the Environmental Protection Agency relating to “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,” Pub. L. No. 117–23, 135 Stat. 295 (2021); See also Env’t Protection Agency, Congressional Review Act Resolution to Disapprove EPA’s 2020 Oil and Gas Policy Rule, Questions and Answers (Jun. 30, 2021), [https://www.epa.gov/system/files/documents/2021-07/qa\\_cra\\_for\\_2020\\_oil\\_and\\_gas\\_policy\\_rule.6.30.2021.pdf](https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf).

<sup>60</sup> See generally 42 U.S.C. §7436. While MERP establishes a number of incentives for operators to reduce methane emissions, Joint Environmental Commenters note that the source-specific standards discussed below are reasonably cost-effective independent of the MERP incentives. EPA should focus the implementation of MERP on achieving reductions of methane beyond those that will be achieved by the standards and guidelines that are finalized. See Comments of Clean Air Task Force et al., Comments in Response to Request for Information – Methane Emissions Reduction Program, (Doc. ID No. EPA-HQ-OAR-2022-0875-0031) (Jan. 18, 2023), <https://www.regulations.gov/comment/EPA-HQ-OAR-2022-0875-0031>.

an NSPS.<sup>61</sup> The commenter notes that roughly two years before EPA’s current proposal, EPA in the 2020 Policy Rule acknowledged two statutorily-mandated threshold questions that necessarily flow from this language of the CAA that must be answered before issuance of CAA section 111 standards:

- *Methane-Specific Endangerment Finding.* First, as a predicate to promulgating new source performance standards, the commenter states that the EPA must determine that methane emissions from the oil and gas sector contribute significantly to endangerment.<sup>62</sup> That is, a pollutant-specific endangerment finding for the source category requires EPA to determine that methane emissions from the oil and gas sector have a significant effect on global surface temperatures. After all, according to the commenter, Congress unambiguously applied the significant contribution finding requirement not only to the source category (here, the oil and gas sector), but also to the “air pollution” (here, methane) that actually causes the endangerment.<sup>63</sup> As EPA previously (and rightly) reasoned, “because Congress limited EPA to regulating only stationary sources in a category that the Administrator must first determine to cause or contribute significantly to dangerous pollution, it is not reasonable to read ‘air pollutants’ to refer to any of the source category’s air pollutants for which EPA has not made a [significant contribution finding].”<sup>64</sup>
- *Meeting Articulated Criteria for Judging Significance of Contribution.* Second, the commenter notes that the EPA should articulate criteria for distinguishing between a “contribution” and a “significant contribution” to dangerous pollution and, before regulating under CAA section 111, must conclude that the pollutant and source category being assessed meet the test for the latter.<sup>65</sup> The commenter contends that the EPA has sensibly pronounced that without articulated criteria, “it is impossible to evaluate whether

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<sup>61</sup> 42 U.S.C. §7411(b)(1)(A)-(B); EPA has no discretion to act beyond the power delegated to it by Congress. *Utility Air Regulatory Group v. EPA*, 573 U.S. 302, 315 (2014). Courts have “typically greet[ed]. . . with a measure of skepticism” situations “[w]hen an agency claims to discover in a long-extant statute an unheralded power to regulate a significant portion of the American economy.” *Id.* at 324. See also *West Virginia v. EPA*, 142 S.Ct. 2587, 2610 (2022).

<sup>62</sup> 85 Fed. Reg. 57,018, 57,033-34 (Sep. 14, 2020) (“If the Administrator did not, when listing the source category, determine that a particular air pollutant causes or contributes significantly to dangerous air pollution, then the Administrator must do so as a predicate to promulgating standards of performance for that air pollutant.”).

<sup>63</sup> *Id.* at 57,035 (“It follows that the air pollutants for which the Administrator must establish standards must, or at least may reasonably, be limited to those air pollutants which contribute to this dangerous air pollution.”); see *Motor and Equip. Manufacturers Ass’n of the United States, Inc. v. NYSDEC*, 627 F.2d 1095, 1113 (D.C. Cir. 1979) (“Congress was certainly capable of adding the phrase ‘accompanying enforcement procedures’ wherever the word ‘standards’ appeared if it desired the statutory findings to apply to both. We see no reason to assume that its failure to do so is attributable to sloppy draftsmanship.”); see also *U.S. v. Menasche*, 348 U.S. 528, 538-39 (1995) (“[E]very clause and word of a statute” must be given effect.).

<sup>64</sup> 85 Fed. Reg. at 57,037.

<sup>65</sup> 84 Fed. Reg. 50,244, 50,268 (Sep. 24, 2019) (“Congress has made it clear that in order to be subject to regulation, the emissions must have a greater impact than a simple contribution.”); 85 Fed. Reg. at 57,038 (“[T]he EPA concludes that the failure to identify any such standard or any established set of criteria for the 2016 Rule’s SCF for methane emissions from the source category is unreasonable ....”; cf. *Catawba Cty. v. EPA*, 571 F.3d 20, 39–40 (DC Cir. 2009) (holding that in determining whether an area “contributes” to downwind ozone air quality problems, the EPA, “[t]o be reasonable . . . must . . . define and explain the criteria the agency is applying”; explaining that the EPA adopted a set of nine criteria that it defined and explained “in spades”).

[a significant contribution finding] is well reasoned.”<sup>66</sup> In the absence of articulated criteria, the commenter states that any prior or present-day determination of significant contribution or “rational basis” EPA may claim is arbitrary.<sup>67</sup>

The commenter (2254-PBPA) asserts that EPA has answered neither of these questions. The commenter states that EPA provides that a prior CAA section 111 rulemaking “establishe[s] the agency’s authority to regulate these methane emissions.”<sup>68</sup> The commenter notes that rulemaking relies on the 2009 endangerment finding (specific to GHGs, not methane) and a 1979 listing of the general oil and gas source category, and primarily focuses on emissions of sulfur dioxide (SO<sub>2</sub>), volatile organic compound (VOC), and GHGs (not specifically methane). The commenter maintains the EPA also asserts that “in the legislative history of the CRA resolution, Congress made clear its intent that CAA section 111 did not require or authorize a pollutant-specific significant contribution finding, and the EPA confirmed that it agreed with that interpretation,”<sup>69</sup> and that “[t]he legislative history of the CRA joint resolution rejected the position that a standard or criteria is necessary for determining significance.”<sup>70</sup> The commenter provides that legislative history embodied in a House Committee Report or in Senate floor statements is not the law.<sup>71</sup>

Although Congress disapproved the 2020 Policy Rule under the CRA, the commenter (2254-PBPA) states EPA is still obliged to follow the express terms of the statute and answer these questions. The commenter provides that EPA’s proposal “broaden[s] the types of sources” subject to regulation and requires, “for the first time[,] regulation of hundreds of thousands of existing sources across the country.”<sup>72</sup> The commenter also notes that EPA projects that the rule as proposed would result in an annual domestic oil production decline of 21 million barrels,<sup>73</sup> which will likely cause another country—undoubtedly with relatively less stringent emission control requirements—to seize the opportunity to increase production (and methane emissions) accordingly.<sup>74</sup> The commenter states that the EPA should analyze how lowering production in the U.S. affects the world and whether such reductions will lead to increased production and increased emissions in other countries.

Response II-2-6: The EPA addressed these comments in the preamble and in Volume I, Chapter 3 of this RTC.

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<sup>66</sup> 85 Fed. Reg. at 57,038.

<sup>67</sup> Id. (“[T]he lack of a standard or established set of criteria for the 2016 Rule’s [significant contribution finding] renders the finding arbitrary and capricious.”).

<sup>68</sup> 87 Fed. Reg. at 74,719.

<sup>69</sup> Id. at 74719.

<sup>70</sup> Id.

<sup>71</sup> *Epic Systems Corp. v. Lewis*, 138 S. Ct. 1612, 1631 (2018) (“[L]egislative history is not the law.”); *National Ass’n of Broadcasters v. F.C.C.*, 569 F.3d 416, 422 (D.C. Cir. 2009) (“[C]ourts have no authority to enforce [a] principl[e] gleaned solely from legislative history that has no statutory reference point.”).

<sup>72</sup> EPA’s Proposal to Reduce Methane Emissions from the Oil and Natural Gas Industry: Technical Overview, available at <https://www.epa.gov/system/files/documents/2021-11/2021-oil-and-gas-proposals.technical-overview-fact-sheet-11.2.2021.pdf>.

<sup>73</sup> 87 Fed. Reg. at 74,782.

<sup>74</sup> As just one example, if the proposed rule is finalized PBPA projects a 9 percent increase in global methane emissions were Turkmenistan to incrementally replace our lost domestic oil production.



## 2.2 Zero-Emission Standard as BSER for Range of Operations

Comment: Commenter (2202-TXOGA) reiterates their objections to the presumptive standards on specific technical or other grounds. For example, in its initial comments, the commenter had noted EPA’s proposal to “issue a zero-emission standard as achievable by BSER for certain new and existing sources.”<sup>75</sup> The commenter expressed “fundamental concerns” with the approach EPA was describing, given that that approach began with a determination of BSER that was “not achievable across the range of operations that are necessary for the source category.”<sup>76</sup> The commenter explained that this would result in a structure under which companies would be required to “demonstrate that they qualify for an exception from a general rule,” thereby shifting the “burden of proof from EPA to the source, on a case-by-case basis.”<sup>77</sup> But, legally, it was EPA’s own obligation to “define BSER based on the statutory definition” – i.e., EPA is required in the first instance to “establish the BSER based on the expected operational situation” of the facilities being regulated.<sup>78</sup> In other words, the commenter states that it was incumbent on EPA to tailor any zero-emissions standard only to those facilities “for which it is adequately demonstrated to be consistent with the statutory definition.”<sup>79</sup>

The commenter (2202-TXOGA) states that EPA seemed to be suggesting that it could set zero-emission standards as BSER even in those circumstances where it knew and acknowledged that the chosen BSER was not feasible in many circumstances. As EPA stated it, such standards were allowable on the basis that “[a]n ‘adequately demonstrated’ system need[] not be one that can achieve the standard ‘at all times and under all circumstances.’” But the commenter pointed out that this “misconstrues the scope of *Essex Chemical*,” insofar as the court “was simply articulating the well-established principle, first enunciated in *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d 375 (D. C. Cir. 1973), that CAA ‘[s]ection 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present.’”<sup>80</sup>

This observation of the court in *Portland Cement*, according to the commenter (2202-TXOGA), is particular pertinent here, where, in its December 2022 supplemental proposal, EPA proposes to find for purposes of EG OOOOc that (i) the BSER for the designated facility pneumatic controllers: Natural gas-driven that Vent to the Atmosphere” to be the “use of zero-emissions controllers”; and (ii) the BSER for the designated facility pneumatic pumps to be the “[u]se of zero-emission pumps that are not powered by natural gas.” In setting presumptive standards of performance for designated facilities under CAA section 111(d), the commenter asserts that EPA must be especially cognizant of the fact that deriving a “best system of emission reduction” for a

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<sup>75</sup> TXOGA January 2022 Comments at 19.

<sup>76</sup> Id. at 20.

<sup>77</sup> Id.

<sup>78</sup> Id.

<sup>79</sup> Id.

<sup>80</sup> TXOGA January 2022 Comments at 21 (quoting *Portland Cement Ass’n v. Ruckelshaus*, 486 F.2d at 391. In *Portland Cement*, the court began its analysis by “rejecting the suggestion of the cement manufacturers that the Act’s requirement that emission limitations be ‘adequately demonstrated’ necessarily implies that any cement plant *now in existence* be able to meet the proposed standards.” 486 F.2d at 391 (emphasis added). As the court noted, “Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for *new plants*.” Id. (emphasis added). Under the CAA, the court noted, emissions from existing sources were to be “controlled through other regulatory authority.” Id.

particular category of *existing sources* can involve fundamentally different considerations than when the Agency is looking to determine BSER for the same category of new sources. In the specific case here, where EPA has proposed to set zero-emission standards for pneumatic controllers and pneumatic pumps, the commenter notes that EPA has not even suggested that such standard is “achievable across the range of operating conditions” of those existing sources, nor does the proposal “attempt to limit it to the conditions for which it might be achievable.”<sup>81</sup>

Response II-2-7: To the extent that the commenter is suggesting that zero emission standards are never permitted under section 111(b) of the CAA, EPA disagrees. There is nothing within the text of CAA section 111 that supports such a position. As a general matter, EPA’s BSER analyses for promulgating NSPS are often based on aggregate information and assumptions that EPA has reason to believe would hold true for the vast majority of affected facilities. This aggregate approach is evident by examining EPA’s use of model plants in the BSER analysis. EPA was especially reasonable to utilize such an approach here for the oil and natural gas industry because the industry includes a wide variety of sources in different configurations and the NSPS is establishing industry-wide standards of performance for sources across the country. EPA did acknowledge the possibility that the aggregate information used for the BSER analysis may not be true and entirely accurate for all affected facilities (that there may be outliers). Commenters had two opportunities to provide input on EPA’s aggregate information and analysis. Further, EPA’s acknowledgment regarding the possibility of outliers does not render the BSER analysis insufficient or EPA’s approach contrary to the CAA. In this situation, it is reasonable for EPA to fulfill the requirements of the CAA by basing decisions on representative industry information. It is unreasonable, and perhaps even impossible, for EPA to consider the unique circumstances of each source, of which there could be thousands or hundreds of thousands in this industry, when setting industry-wide standards. Where EPA found that certain characteristics, or circumstances, were present in a sizable portion of the industry and such facts were relevant to the BSER analysis (the facts related to the elements or “inputs” that EPA examines for the BSER analysis), EPA’s final NSPS includes subcategories based on those facts. One example of this are the final standards for pumps which includes a subcategory with a different standard for sites without access to grid electricity that have less than 3 diaphragm pumps. Another example is the subcategory with a different standard for process controllers at sites in Alaska without access to grid electricity.

Where the final NSPS includes zero emissions standards, the EPA has demonstrated in each of those cases that this “degree of emission limitation [is] achievable through the application of the best system of emission reduction which...the Administrator [has] determine[d] has been adequately demonstrated.” CAA 111(a)(1). For EPA to demonstrate that the best system of emission reduction has been “adequately demonstrated,” EPA does not need to prove beyond any doubt that each and every affected facility is capable of utilizing the system that EPA examined in the Agency’s BSER analysis. Imposing such an onerous requirement, as commenters suggest, would put EPA in an absurd position such that promulgating any standard of performance for this source category would be nearly impossible. Lastly, EPA does not agree with commenter that the Agency misconstrued *Essex Chemical*. As stated in the 2021 Proposal, an “adequately demonstrated system” is one that “has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without

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<sup>81</sup> TXOGA January 2022 Comments at 22.

becoming exorbitantly costly in an economic or environmental way.” *Essex Chemical*, 486 F.2d at 433.

Further, the fact that some zero emissions standards included in the final NSPS allow sources to comply via means other than the primary control method assessed for the BSER analysis does not render the BSER analysis flawed. When EPA’s standards in a NSPS can be expressed as numerical limitations, sources are free to choose how they comply with those standards. To the extent that EPA acknowledged that certain control options evaluated might not be feasible or preferable for certain sources, and where EPA specifically discussed other methods of compliance, it was done so to highlight that sources have options. In many, if not all, situations where the NSPS requires compliance with a zero emission standard sources have options such that if one compliance method does not work for them for some reason, they can choose another method of compliance. EPA’s proposal preambles highlight the degree of flexibility that sources have when complying with zero emissions standards. EPA does not agree with the commenter’s implication that allowing alternatives to achieve equivalent emission reduction somehow renders the BSER analysis flawed. Lastly, EPA does not agree that including limited exemptions for specific technical and safety reasons renders the BSER analysis flawed. For EPA’s full response to those comments, see Response II-2-13.

To the extent that the commenter is claiming that EPA erred in including presumptive standards in the final EG that are similar to the finalized standards in the NSPS (commenter is relying on *Portland Cement*), see section XIII.C.1 of the preamble. That section explains EPA’s position on this subject and is responsive to this portion of the comment.

To respond to the comments regarding the presumptive standards in the final emission guidelines (OOOOC) for process controllers and pumps, see sections XI.D and XI.E of the final rule preamble.

## **2.3 Legal Basis – Certification of Technical Infeasibility**

Comment: Commenter (2428-API) notes that applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed 40 CFR 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., 40 CFR 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., 40 CFR 60.5376b(c)(2)(ii)(B)(2)). The commenter provides that the EPA imposes these certification requirements out of concern about the possible “abuse” of these provisions such that they might open a “loophole” in the regulations (87 FR 74776). EPA stresses that it, “wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.” *Id.* Thus, the commenter states that the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., “significantly flawed”) certifications. The commenter supports these opt out provisions as a practical matter. The commenter agrees that non-emitting measures and methods should be used where they are

technically feasible and cost effective, but EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution to the commenter.

However, the commenter (2428-API) does not believe that EPA has asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. The commenter points out in their comments on the original November 2021 proposal that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA section 111 because non-emitting standards are not “adequately demonstrated” if opt outs are needed to make them feasible and workable.

The commenter (2428-API) reiterates those concerns about the legal basis for EPA’s opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. The commenter contends that such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. According to the commenter, that heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Response II-2-8: See Response II-2-7 for responses to portions of this comment that discuss EPA’s BSER analysis and the concept of “adequately demonstrated” under CAA section 111. In addition, EPA does not agree that including certain provisions providing exceptions from the general standard, which the commenter terms “opt outs,” in the final NSPS renders zero emissions standards inadequate. First, the final NSPS does not include some iterations of certain exceptions that EPA had proposed. For example, the final new source standards for Associated Gas, after the phase-in period for compliance, no longer allow for technical infeasibility determinations. Next, the oil and natural gas industry includes a wide variety of sources in a wide variety of configurations. The exceptions that commenter takes issue with were generally designed to account for the possibility that legitimate safety, operational, and/or technical reasons may exist at some sources that could render compliance with the final standards a hazard to human safety or technically impossible from an engineering perspective. Such circumstances are the exception and not the norm. Put another way, the vast majority of the industry will not need to use any exceptions included in the final NSPS because they will be able to meet the standards.

The exceptions are only to be used in very limited and specific circumstances, and EPA does not expect them to be used often. For reasons explained within each BSER analysis for each relevant affected facilities where this issue is presented, EPA has explained how and why the best system has been “adequately demonstrated.” The fact that EPA sometimes allows very limited exceptions does not render that demonstration invalid, but rather is consistent with EPA’s authority under CAA section 111(b)(2) to distinguish sources with different characteristics

(“classes, types, and sizes”) when establishing such standards. EPA has also explained how and why certain exceptions are included in the final NSPS. The reasoning for including, or not including, a particular exception is fact-specific to the affected facility and the related standard and is therefore located within the discussion for the relevant affected facility. As explained in the context of each exception, EPA has reason to believe that a very limited set of sources may present unique characteristics such that a variation of the final standard is warranted to account for those situations. EPA has a history of allowing these kinds of limited variations in the oil & gas source category, and in other NSPS, because of the many different configurations in the field.<sup>82</sup>

We disagree with commenter's characterization of the certification requirement as 'onerous and potentially punitive.' Certification is appropriate to ensure any reliance on the exception is legitimate and based on a sound engineering analysis, and that the exception does not become a compliance loophole. Flaws in the certified engineering analysis may result in the exception being inapplicable and a related enforceable violation of the standards. Fraudulent or significantly flawed certifications may result in both civil and criminal liability and penalties for the owner, operator, and the person that makes the certification. These consequences are consistent with, and no more "punitive" than, those for any other violation or certified, fraudulent statement submitted to EPA.

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<sup>82</sup> Allowances for technical infeasibility have been included in prior EPA rules for this and other industries. For example, technical infeasibility is a factor to consider within the gas well standards in 40 CFR Part 60 Subpart OOOO: “[r]oute the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function.” 40 CFR § 60.5375(f)(2). By way of another example where the assertion of technical infeasibility must be certified, see the standards for pumps within Subpart OOOOa found at 40 CFR § 60.5393a(b)(5).

## Chapter 3. Effective, Applicability and Compliance Dates/Definitions

### 3.1 New, Modified, or Reconstructed Source for Purposes of the Proposed NSPS OOOOb Applicability Date

Comment: Commenters (2157-Tennessee Department of Environment & Conservation (TNDEC), 2202-Texas Oil & Gas Association (TXOGA), 2221-Texas Pipeline Association (TPA), 2227-Western Energy Alliance (WEA), 2238-Southeastern Ohio Oil and Gas Association, 2240-Rose Rock Environmental Services, LLC (RRES), 2247-Ohio Environmental Protection Agency (OHEPA), 2248-North Dakota Petroleum Council (NDPC), 2252-Petroleum Association of Wyoming (PAW), 2254-Permian Basin Petroleum Association (PBPA), 2292-West Virginia Office of the Attorney General *et al.*, 2294-Ohio Oil & Gas Association (OOGA), 2326-American Exploration and Production Council (AXPC), 2354-Business Roundtable, 2360-Devon Energy, 2399-GPA Midstream Association (GPA), 2428-American Petroleum Institute (API), 2483-Interstate Natural Gas Association of America (INGAA), Others) state that the November 2021 proposal lacked regulatory text or sufficient factual and technical basis and therefore should not be used to define new sources for purposes of New Source Performance Standards (NSPS) OOOOb. Some of the specific comments provided are included in the following paragraphs.

Commenter (2326-AXPC) recommends that EPA extend implementation timelines – particularly for sources that became NSPS OOOOb affected facilities prior to the date of final rule publication. The commenter urges that EPA provide additional time for certain affected facilities to come into compliance following the final rule’s effective date if those facilities that became new, modified, or reconstructed after the NSPS OOOOb “new” facility trigger date (*i.e.*, November 15, 2021, as proposed by EPA; and December 6, 2022, as requested by the commenter) and before the final rule’s *Federal Register* publication date. The commenter explains that until the effective date of NSPS OOOOb, some of these facilities would be unregulated under an existing NSPS or would begin operating as NSPS OOOOb affected facilities and may then need to complete retrofits to comply with newly applicable NSPS OOOOb standards. By way of example, the commenter explains that NSPS OOOOb pneumatic controllers and pumps are not subject to a zero emissions standard but would be subject to zero emissions standards under NSPS OOOOb, requiring retrofit within 60 days of the final rule’s publication in the *Federal Register*. The commenter states that this is not enough time to acquire retrofit equipment that will be in high demand, and likely short supply, as operators across the country place orders for equipment to meet the zero emissions standard. In addition, the commenter notes that operators must acquire engineering resources to engineer the installation of zero emissions pneumatic controller systems and that these engineering resources, too, are likely to be in high demand and short supply.

Commenter (2157-TNDEC) believes that new sources should be based on the publication date of the December 2022 supplemental proposal rather than the November 2021 proposal because the November 21, 2021, proposal did not contain sufficient factual and technical basis for meaningful comments to be developed. The commenter states that the D.C. Circuit has noted:

An . . . important component of the process of reasoned decision-making is the agency's own explanation for the rules it adopts. While an agency need not justify the rules it selects in every detail, it should explain the general bases for the rules chosen.<sup>1</sup>

The commenter (2157-TNDEC) requests that EPA consider the practical implications of giving sources and state regulators time to understand new federal rules and implement actions necessary to comply with new federal rules. The commenter contends that without regulatory language it was difficult, if not impossible, for potentially regulated sources to determine if they would be subject to the proposed regulation. Furthermore, the commenter states that the December 2022 supplemental proposal included sources that were not addressed in the November 2021 proposal. According to the commenter, the goal of the Clean Air Act (CAA) is not to drive reductions in ways that harm business, and the commenter believes that by defining new sources by the date of the December 2022 supplemental proposal, the rule will provide a pathway for reductions but will also give businesses and regulators time to understand what implementation for compliance will entail.

Commenter (2202-TXOGA) notes that the initial November 2021 proposal, effectively without discussion or explanation, includes an applicability date for new, modified, and reconstructed sources subject to NSPS OOOOb of November 15, 2021, which they assert was not legally permissible as the CAA defines a “new source” as “[a]ny stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.”<sup>2</sup> The commenter states that EPA seeks to codify this date despite the comments to the contrary on the November 2021 proposal.

Based on the preamble of the December 2022 proposal, the commenter (2202-TXOGA) notes EPA had not utilized the stated flexibility by the Administrative Procedures Act (APA) previously, instead providing regulatory text in all prior NSPS proposals.<sup>3</sup> According to the commenter, soliciting comment on “whether CAA section 111(a) provides the agency discretion to define ‘new sources’ based on the publication date of a supplemental proposal”<sup>4</sup> and “[i]f so,” the preamble asks whether “there are any unique circumstances here that would warrant the exercise of such discretion in this rulemaking,”<sup>5</sup> turns the proper inquiry on its head. The question the commenter raises is not whether Congress gave EPA the “discretion” to set some date other than November 15, 2021, as the applicability date trigger for Quad Ob for new sources. Instead, the commenter urges EPA, before the Agency takes final action here, to

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<sup>1</sup> *Conn. Light & Power Co. v. Nuclear Regulatory Com.*, 673 F.2d 525, 528 (D.C. Cir. 1982).

<sup>2</sup> CAA §111(a)(2); 42 U.S.C. §7411(a)(2)

<sup>3</sup> And this was the case even though the Agency had been facing increasing costs from the Office of the *Federal Register* and was under pressure to reduce such costs. Had EPA considered non-publication a legal option previously, it is reasonable to conclude that the budget pressures of the past decade would have prompted this action, but they did not.

<sup>4</sup> 87 Fed. Reg. at 87,716.

<sup>5</sup> *Id.* First, as the commenter (2202-TXOGA) pointed out in its January 2022 comments, the language of CAA section 111(a)(2), defining “new source” for purposes of the NSPS program, reveals no evident ambiguity: a “new source” is “[a]ny stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.”

evaluate whether EPA has authority under the CAA to set November 15, 2021, as the applicability date in the first place and believes the statute does not grant such authority.

Instead, the commenter (2202-TXOGA) notes that the preamble simply asserts that nothing in CAA section 307(d)(3) requires that a “notice of proposed rulemaking” proposing regulations under CAA section 111 requires that the proposal contain “proposed regulatory text.”<sup>6</sup> As has been noted, however, under the plain language of CAA section 111(a)(2), a “new source” for NSPS applicability purposes is defined in relation to the date when EPA has published – either in final or proposed form – “regulations . . . prescribing a standard of performance.” The commenter contends that even if EPA were permitted under CAA section 307(d)(3) to withhold proposed regulatory language at the time it publishes a notice of proposed rulemaking (which, as is argued below, it is not), such publication, sans regulatory text, would not constitute the “publication of... proposed regulations” within the meaning of CAA section 111(a)(2).

The commenter (2202-TXOGA) states that the proposal’s reliance on the language of APA, 5 U.S.C. section 553, which explicitly provides that a notice of proposed rulemaking may contain “either the terms or substance of the proposed rule” or a “description of the subjects and issues involved,” ignores the fact that the “promulgation of revision of any standard of performance under” CAA section 111 is conducted pursuant to the more elaborate procedures and requirements set forth in CAA section 307(d), not the APA.<sup>7</sup> The commenter contends that CAA section 307(d) requires more than a “description of issues.” It requires disclosure of the “factual data on which the proposed rule is based” and the “legal and policy considerations underlying the proposed rule.” According to the commenter, a rule must be a part of a CAA section 307(d) proposal in order to disclose its factual, legal, and policy basis. They add that they believe that there is simply no footing on which to moor a claim that providing a “description of the subjects and issues involved” in a notice of proposed rulemaking would satisfy the disclosures required under CAA section 307(d) with respect to “the proposed [CAA section 111] rule,” much less that

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<sup>6</sup> 87 Fed. Reg. at 87,716. The Proposal’s reliance on the language of APA, 5 U.S.C. section 553, which explicitly provides that a notice of proposed rulemaking may contain “either the terms or substance of the proposed rule” or a “description of the subjects and issues involved,” ignores the fact that the “promulgation of revision of any standard of performance under” CAA section 111 is conducted pursuant to the more elaborate procedures and requirements set forth in CAA section 307(d), not the APA.

<sup>7</sup> Some 40 years ago (and just six years after Congress had first enacted CAA section 307(d) as part of the CAA Amendments of 1977), the U.S. Court of Appeals for the District of Columbia Circuit had occasion in *Small Refiners Lead Phase-Down Task Force v. EPA*, 705 F.2d 506 (D.C. Cir. 1983) to point out that there were “basically two major differences between APA § 553(b) and Clean Air Act §307(d)(3).” *Id.*, 705 F.2d at 519. The first of these “major differences,” the court explained, is that the “Clean Air Act, unlike the APA, requires EPA to issue a ‘proposed rule.’” *Id.* The court acknowledged that while “§307(d)(3) does not explicitly require EPA to issue a proposed rule,” that section of the CAA does “refer[] to the agency’s duty to explain ‘the factual data on which the proposed rule is based’ and ‘the major legal interpretations and policy considerations underlying the proposed rule.’” *Id.* (emphasis in original). Also, the court continued, “at the final rule stage, §307(d)(6) requires EPA to explain ‘any major changes in the promulgated rule from the proposed rule.’” *Id.* In the court’s view, “EPA cannot comply with these statutory requirements unless it issues a ‘proposed rule.’” *Id.* The court added that it, in observing the evident need for a notice of proposed rulemaking to include a “proposed rule,” it “express[ed] no view on whether the ‘proposed rule’ must take any particular form,” save that it must be “specific enough to comply with § 07(d).” *Id.* at 519 n. 27.



such a “description” is equivalent to the “publication of . . . proposed regulations” within the meaning of CAA section 111(a)(2).<sup>8</sup>

Moreover, prior to enactment of the CAA Amendments of 1977, and the introduction of more prescriptive rulemaking requirements applicable to specified EPA actions (including the promulgation of standards of performance under CAA section 111), the commenter (2202 - TXOGA) provides that rulemakings to establish standards under CAA section 111 were governed by the less prescriptive requirements of the APA, 5 U.S.C. §553. They note that this fact, in turn, provides an explanation for what, at first glance, may seem an odd formulation in CAA section 111(a)(2), in which Congress defined a “new source” as a source whose construction or modification is commenced after the “publication of [final] regulations (or, if earlier, proposed regulations) prescribing a standard of performance . . . .” . Since the promulgation of a final standard of performance under CAA section 111(b) will always be preceded by a notice of proposed rulemaking, they believe that Congress’s use of the term “proposed regulations” in CAA section 111(a)(2) can only be construed as being a reference to proposed regulatory text and not to any other contents (such as the preamble) in the notice of proposed rulemaking. Otherwise, the commenter suggests that CAA section 111(a)(2)’s invocation of the words “if earlier” would be rendered nonsensical. When Congress first enacted CAA section 111 in 1970, the commenter provides that it recognized that, as EPA itself has pointed out, the agency was not compelled by the then-governing provisions of the APA, 5 U.S.C. Section 553, to publish proposed regulatory text in the *Federal Register*, and that the agency had the option under the APA to provide instead in the notice of proposed rulemaking simply a description of the “subjects and issues involved.” The commenter explains that in keeping with Congress’s intent at the time that rulemakings to prescribe standards of performance under CAA section 111 were to be conducted expeditiously, and that regulated entities would be prompted to take account of, and comply with, those standards as soon as was practicable, Congress allowed that the applicability date for standards adopted for a “new source” could be fixed at the time “proposed regulations” were published, but only if EPA had embraced the first of the APA’s two listed options and had included with the notice of proposed rulemaking the “terms or substance of the proposed rule” – *i.e.*, proposed regulatory text – so as to ensure that regulated entities had adequate notice of the specific terms of what EPA was proposing.

According to the commenter (2202-TXOGA), it is not exactly clear what argument is being advanced in support of the position that EPA is authorized, or compelled, to set November 15, 2021, as the applicability date for NSPS OOOOb. The commenter provides that EPA seeks to suggest, without ever saying as much – again, in addressing this point in its December 2022 supplemental notice, the preamble never engages the pertinent language of CAA section 111(a)(2) – that, by having met the requirement under CAA section 307(d)(3) to publish what it considers to be a sufficiently detailed “statement of basis and purpose” (*i.e.*, the preamble that constituted the November 15, 2021 notice), the Agency has, in effect, published a “proposed

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<sup>8</sup> The commenter does not agree that section 307(d) bears EPA’s reading of it. Under EPA’s interpretation, it seems that no regulatory language would ever need to be published, even language setting forth final regulations – since EPA’s reasoning for not publishing the proposed regulatory text is based on statutory language in section 307(d) that is identical for final rules – nothing in section 307(d) refers to publishing final rule language, yet we are aware of no situation in which EPA failed to provide final rule language when issuing a rule.

regulation” within the meaning of CAA section 111(a)(2), and that the Agency was under no further obligation to publish or make available any regulatory text. The commenter does not consider this approach sustainable. In effect, the position appears simply to be a claim that the preamble to a notice of proposed rulemaking is (or, at least, can be) equivalent to a “proposed regulation.” The commenter notes that it is true that the term “regulation,” while used throughout the CAA (including, most significantly for present purposes, in CAA section 111(a)(2)), is nowhere defined in the CAA, or, for that matter, in the APA (where the operative defined term is “rule”), nor is the term “regulation” defined in the Federal Register Act (FRA).<sup>9</sup> In the commenter’s view, the Proposal seems to suggest that the preamble to a notice of proposed rulemaking can itself be viewed as a proposed “regulation” generally, or even that the publication of a notice of proposed rulemaking without any accompanying proposed regulatory text, can constitute the publication of “proposed regulations . . . prescribing a standard of performance” within the meaning of CAA section 111(a)(2). While the FRA contains no definition of “regulation,” the commenter states that the FRA’s own implementing rules do specify that the terms “regulation” and “rule” “have the same meaning” and that the terms can be used interchangeably.<sup>10</sup> Elsewhere, they note that the FRA’s implementing rules provide that, “[p]ursuant to chapter 15 of title 44, United States Code, the Director of the *Federal Register*” is to “publish periodically a special edition of the *Federal Register* to present a compact and practical code called the ‘Code of Federal Regulations,’ to contain each Federal regulation of general applicability and legal effect.”<sup>11</sup> The commenter contends that since a preamble that accompanies a notice of final rulemaking is itself never published in the Code of Federal Regulations, such a preamble can never be characterized as being a “regulation.”<sup>12</sup> As such, the commenter explains that it follows that the preamble to a notice of proposed rulemaking can never be characterized as a “proposed regulation” – much less a “proposed regulation . . . prescribing a standard of performance” within the meaning of CAA section 111(a)(2) – no matter how much EPA may wish it to be so. The commenter requests that EPA reconsider its position, repropose the rule with regulatory text, and, in the final rule, establish the applicability date for

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<sup>9</sup> The FRA is the federal statute that authorizes the Administrative Committee of the *Federal Register* to prepare and publish “in special or supplemental editions of the *Federal Register*” the “complete codifications of the documents of each agency of the Government having general applicability and legal effect, issued or promulgated by the agency by publication in the *Federal Register*,” which “complete codifications” are to be “designated as the ‘Code of Federal Regulations.’” See 44 U.S.C. § 1510(a), (b). The FRA specifically defines “document,” as used therein, to mean a “Presidential proclamation or Executive order and an order, regulation, rule, certificate, code of fair competition, license, notice, or similar instrument, issued, prescribed, or promulgated by a Federal agency.” 44 U.S.C. § 1501. But the FRA itself provides no definition of the term “regulation” or, for that matter, the term “rule.”

<sup>10</sup> See 1 C.F.R. § 1.1.

<sup>11</sup> 28 See 1 C.F.R. § 8.1. Notably, the phrase “each Federal regulation of general applicability and legal effect” tracks in certain significant respects the APA’s definition of the term “rule.” As is relevant here, the APA defines “rule” to mean the “whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy.” See 5 U.S.C. § 551(4). Hence, that FRA’s implementing rules equates the terms “regulation” and “rule” makes sense.

<sup>12</sup> Cf. *Brock v. Cathedral Bluffs Shale Oil. Co.*, 796 F.2d 533 (D.C. Cir. 1986). While the D.C. Circuit had no occasion in *Cathedral Bluffs* to address the precise point at issue here, then-judge Scalia, in assessing the status of a policy statement adopted by the Secretary of Labor – which policy statement the Labor Department had formally published in the *Federal Register* – took pains to note that the “real dividing point between regulations and general statements of policy is publication in the Code of Federal Regulations, which the statute authorizes to contain only documents ‘having general applicability and legal effect,’ 44 U.S.C. § 1510 (1982), and which the governing regulations provide shall contain only ‘each Federal regulation of general applicability and current or future effect,’ 1 C.F.R. § 8.1 (1986).” *Id.* 796 F.2d at 539 (emphases in original).

new sources subject to NSPS OOOOb no earlier than the date that EPA finally publishes in the *Federal Register* proposed regulatory text according to the CAA.

Additionally, the commenter (2202-TXOGA) suggests that even if this interpretative approach to CAA section 307(d) in general were supported, the special applicability structure of CAA section 111 means that, for purposes of NSPS, the publication of the proposed regulatory text is required. In enacting CAA section 111, the commenter states that Congress determined that, in those circumstances where regulated entities had been provided adequate notice of the specific contents of EPA's proposed standard – *i.e.*, by being afforded the proposed regulatory text at the time of proposal, which they could evaluate and comment upon, setting the final standard's applicability date on the basis of the date on which the standard had been proposed would not result in any prejudicial retroactive application. The commenter notes that such retroactivity “is not favored in the law.”<sup>13</sup> To this end, the commenter asserts that this is why Congress mandated that final rules must quickly follow proposal under CAA section 111, in essence taking steps to minimize any possible prejudicial retroactivity. The commenter adds that CAA section 111 thus requires EPA to “afford interested persons an opportunity for written comment on . . . proposed regulations” to establish a standard of performance, and then, “[a]fter considering such comments,” to promulgate the final standard “within one year after such publication . . . with such modifications as [the Administrator] deems appropriate.”<sup>14</sup> The commenter states that this “one year” promulgation deadline reflects a change made to CAA section 111(b)(1)(B) by the CAA Amendments of 1990. Prior to that time, CAA section 111(b)(1)(B) had specified that “[a]fter considering such comments, [EPA] shall promulgate within 90 days after such publication, such standards with such modifications as he deems appropriate.”<sup>15</sup>

According to the commenter (2202-TXOGA), the extraordinarily abbreviated time that Congress has allotted to EPA to take final action on a proposed standard of performance underscores Congress's intent that a proposed standard should reflect well (if perhaps not fully) developed thinking on the Agency's part at the outset of the rulemaking process, thus minimizing the risk that setting the applicability date as the date of publication of the proposed regulation will have unacceptable retroactive effect, while balancing that concern with congressional desire that standards of performance be adopted as expeditiously as possible. The commenter asserts that the position in the proposal runs directly afoul of congressional intent in that respect. Due to the time that has passed since EPA published the November 2021 notice; the commenter states that for EPA to set the applicability date based on that publication date would conflict with the Agency's statutory obligation to have finalized the standard within one year (as set out in CAA section 111(b)(1)(B)).

The commenter (2202-TXOGA) maintains that this point is illustrated very well by the current proposed action. The commenter explains that the discussion of potential standards did not fully reflect what was proposed to be required of affected sources, such that an entity completing new installations between November 15, 2021, and release of the regulatory language would be able to sufficiently design its operations to comport with the new standards. The commenter continues that if an affected source is “new” under CAA section 111, it is not afforded the lead time that is

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<sup>13</sup> See *Bowen v. Georgetown University Hosp.*, 488 U.S. 204, 208 (1988).

<sup>14</sup> See CAA §111(b)(1)(B); 42 U.S.C. §7411(b)(1)(B).

<sup>15</sup> See, *e.g.*, CAA 111(b)(1)(B); 42 U.S.C. §1857c-6(b)(1)(B) (1970).

associated with normal project planning to comply with a final rule.<sup>16</sup> The commenter contends that as the November 2021 notice did not contain essential elements such as methods including averaging times, test methods, and the like, affected facilities did not have the “notice” needed to design their new, reconstructed, or modified facilities for compliance in accordance that date being the new source trigger date.

Similarly, commenter (2221-TPA) states that basing the applicability date of the proposed new NSPS OOOOb on the prior publication date, November 15, 2021 - a date over a year before regulated parties were able to see the actual rule language, they may have to comply with is inappropriate. According to the commenter, the provisions of Part 60, including any new or revised performance standard promulgated under section 111(b) of the CAA, apply to “an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, *the date of publication of any proposed standard*) applicable to that facility.”<sup>17</sup> The commenter contends that the “proposed standard” -is the actual rule language, not EPA's prefatory description and explanation - and in some cases, EPA's mere prediction - as to what that rule language might ultimately look like. In the world of complex regulations emission limits, and compliance, details are everything.<sup>18</sup> The commenter provides that a company determining whether, and to what extent, a particular operation is covered by a performance standard may gain some insight or coloration from a preamble, but in the last analysis it is the precise rule language itself that is always carefully scrutinized in order to resolve questions of applicability and required compliance. The commenter states that the key is what the formal rule text says. However, the commenter notes that it was not until December 2022 that companies finally had the benefit of seeing the actual proposed rule language with which they might ultimately be required to comply. The commenter believes that the prior proposal was more in the nature of an advance notice of proposed rulemaking than a rule proposal, and as such it is inappropriate to base the applicability date on the November 15, 2021, publication date.

Additionally, the commenter (2221-TPA) contends that the extended preamble-only publication on November 15, 2021, gave companies no ability to proceed with confidence as to how the rules might ultimately read. For example, they note that the control device monitoring, testing, and recordkeeping requirements, which encompass multiple affected source categories, could not have been determined based on the November 2021 preamble text, as that preamble text only suggested that the requirements should be strengthened while failing to state what the new requirements would be. According to the commenter, merely stating an emission limitation or work practice standard is not sufficient notice, because monitoring, recordkeeping, and reporting requirements are also part of a standard and it is therefore imperative that owners and operators have knowledge of these requirements at the time of construction to be certain that full compliance can be achieved. In short, the commenter asserts that requiring compliance based on

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<sup>16</sup> The commenter maintains that the provision of only 60 days after publication for sources that were constructed, reconstructed, or modified since proposal to comply and demonstrate compliance is unreasonable and unrealistic and it should be revised.

<sup>17</sup> 40 CFR § 60.1(b) (emphasis added).

<sup>18</sup> EPA previously referred to November 15, 2021, as “the date of publication of the proposed revisions to the NSPS,” 86 Fed. Reg. 63117 (Nov. 15, 2021), when that is the date of EPA's description of the upcoming proposed revisions, which would only be revealed over a year later.

a construction or modification date that is months earlier than the publication of actual proposed rule language - *i.e.*, the “proposed standard” described by 40 CFR 60.1(b) - would be unfair and contrary to EPA's own rules, and to proceed in this way would potentially trigger future litigation. The commenter urges EPA to base the applicability dates in these rules on the date of *Federal Register* publication of actual rule language, December 6, 2022, as it has traditionally done, not a preamble description of what such language might look like in the future.

Commenter (2227-WEA) provides that the CAA section 111(a)(2) definition of “new source” uses the term “proposed regulations” in defining the new source applicability date. The commenter contends that the November 2021 publication alone, which was at most a lengthy preamble, cannot constitute proposed regulations or “rules,” the two terms being essentially synonymous, any more than a final rule that is unaccompanied by regulatory text could qualify as a “rule.” Although the November 2021 preamble described the types of regulatory requirements that EPA was considering promulgating, the commenter finds that the preamble was not in and of itself a document “prescribing a standard of performance under this section [111]....” A “prescribed standard” would be established only by the proposed regulatory text, which was not provided until the December 2022 supplemental proposal.

The commenter (2227-WEA) adds that, as required in the CAA, under 42 U.S.C. section 7411(b)(1)(B), requirements for new sources are required to be finalized within one year of the publication of proposed regulations. The commenter states that a final rule was not finished for the sources listed in the 2021 proposal by November 15, 2022, and this provides even more evidence that the initial proposal should never have been classified as a proposed rule. The commenter recognizes that reclassifying the previous publication as an advanced notice of proposed rulemaking (ANPR) would be difficult, if not impossible retroactively; however, they suggest that the EPA has the deference and indeed is required to base the applicability date on this supplemental proposal, *i.e.*, the publication date of the “proposed rules”. Considering also the supplemental rule is the first instance where regulated sources were given fair notice of proposed regulatory language, the commenter contends that it is a more appropriate date for future applicability of the final rule. The commenter contends that this alone would qualify as a “unique circumstance” to justify a change to the proposed applicability date.

Commenter (2240-RRES) states that the first version of the proposed rule did not include regulatory language, a major departure from all other proposed rules previously published by the EPA. Regulatory language, which an operator might reasonably be expected to follow, were not published until December 6, 2022. As such, the commenter believes that the applicability date of the rule should be December 6, 2022.

Commenter (2247-OHEPA) is concerned about the applicability date for the NSPS sources. The commenter notes that historically, when the EPA issues a new NSPS, they first issue draft rules with a comment period. After the comments are reviewed, the final rules are issued. The date the draft rules are published is then used as the applicability date for the NSPS. The commenter states that, in this case, EPA took an additional step where they issued a pre-draft package simply asking for suggestions and comments before drafting rules. This pre-draft package was issued in late 2021. The commenter notes that EPA chose to set the NSPS applicability date based on the pre-draft package, not the official draft rule package.

According to the commenter (2247-OHEPA) the problem with doing this is it adds another year's worth of new or modified facilities that are instantly not in compliance when the final rule comes out. This means companies will have to scramble to modify their facilities and permitting agencies will need to work through more old installation permits to update them to the newly issued NSPS. The commenter recommends that EPA stick to past practices and assign the applicability date to when the draft rules were issued in late 2022. Those new or modified sources installed during 2022 will then fall into the emission guideline (EG) rules which, because of the rule writing process, will allow more time for permittees and permitting agencies to update their systems for the new EG rules.

Commenter (2252-PAW) states that under this Administration, the first iteration was issued on November 15, 2021, and that that iteration was all preamble – no proposed regulatory text was provided. The commenter compares this iteration to an ANPR rather than a proposed rule. The commenter asserts that companies cannot be required to be compliant with a regulation for which there is no text. In the December 6, 2022, supplemental rule proposal, extensive revisions were made demonstrating that companies are not able to make capital investment decisions until regulation certainty. The commenter states that the industry does not know the extent to which EPA will revise this proposed rule on the path to finalization and that EPA should change the effective date to align with the date of issuance of a final regulation. The commenter notes that the CAA requires this in section 111(b)(1)(B): “Standards of performance or revisions thereof *shall* become effective upon promulgation.” (emphasis added) The commenter adds that “promulgate” is defined as “formally putting it into effect” and that this regulation will not be in effect until the EPA issues a final regulation. Further, the commenter states that the EPA is barred from requiring industry compliance until that time, as well.

Commenter (2254-PBPA) expresses that EPA's failure to propose rule text in the November 2021 publication and then selecting November 2021 as the “new source” applicability date departs from decades of NSPS rulemaking practice. According to the commenter, the November 2021 preamble text should be considered an ANPR as the December 2022 proposed rule is generally more stringent than the November 2021 preamble, both in terms of actual prescribed standards that go beyond what was earlier described (“EPA is issuing this supplemental proposal to update, strengthen, and expand the standards ....”<sup>19</sup>), impact (EPA is now projecting annual reductions in crude oil production of 21 million barrels compared to its November 2021 projection of 12 million barrels), and scope (e.g., well head monitoring regardless of relative size). Additionally, the commenter states that although Congress referred to NSPS OOOOb (in reference to a methane fee) in the Inflation Reduction Act (IRA), nothing in the IRA alters or overrides the CAA's applicability date provision or EPA's longstanding implementation of it. Had Congress wanted to, the commenter notes that it could have spoken directly to this issue in the IRA and specified November 2021 as the trigger date for NSPS OOOOb applicability, but it did not do so.

Furthermore, commenter (2254-PBPA) recommends EPA should instead use December 6, 2022, as the new source applicability date. According to the commenter, EPA's reliance on section

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<sup>19</sup> See, e.g., Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources; Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74, 705 (Dec. 6, 2022).

553(b) of the APA, which only requires notice of a proposed rule to include a description of the subjects and issues involved, is misplaced as follows:

- This is a CAA rulemaking, and the NSPS statutory text sets the applicability date based on proposed rules that “prescrib[e]” a standard of performance that “will be applicable” to the source. Indeed, EPA has proposed that the applicability date for dry seal centrifugal compressors be December 2022 because “standards for dry seal centrifugal compressors were not proposed in the November 2021 proposal.”<sup>20</sup> This is true for all sources covered by the December 2022 proposal, as EPA in November 2021 didn’t prescribe any standards that “will be applicable.”
- The CAA’s NSPS applicability date provision requires publication of “proposed regulations.” NSPS-specific provisions supersede the CAA’s and APA general rulemaking provisions in an NSPS rulemaking. Mere description of the “subjects and issues involved” therefore does not suffice. The CAA section 307(d)(3) language EPA cites is intended to describe what must accompany a proposed rule, not what comprises a proposed rule. The very existence of requirements concerning what must accompany the proposed rule confirms the expectation that there is a proposed rule. EPA’s November 2021 proposal failed to include an actual proposed rule, which eliminates meaningful notice and comment because regulated entities, in practice, do not have the luxury of waiting to see what EPA ultimately finalizes. The importance and potential economic impacts of this rulemaking only further serve to justify a December 2022 applicability date.
- EPA cites a Ninth Circuit decision for the proposition that failure to propose in advance the actual wording of a rule does not make the final rule invalid. See *Rybachek v. EPA*, 904 F.2d 1276, 1287 (9th Cir. 1990). That case is distinguishable. First, the subject matter: That case dealt with wastewater discharge regulations promulgated pursuant to a different statute and for which an applicability date wasn’t set by a rule proposal, which has nothing to do with whether a final rule is invalid. Second, the impact: That case dealt with regulations that applied to permits covering a discrete industry (Alaskan placer mining), whereas the NSPS OOOOb regulations would affect millions of new sources across the U.S.

Commenter (2294-OOGA) objects to U.S. EPA’s proposed compliance date of November 15, 2021, particularly given that regulatory text was unavailable as of the proposed compliance date. The commenter contends that EPA maintaining the November 15, 2021, compliance date is unwarranted and will result in companies having a large backlog of new and modified sources that may be subject to NSPS OOOOb. For example, the storage vessel affected source was expanded from individual tanks to tank batteries under the supplemental proposal. If such new/modified storage vessel sources dating back to November 15, 2021, are subject to NSPS OOOOb, companies will need additional time to meet the initial compliance requirements. The commenter also notes that applicable compliance date of November 15, 2021, will likely result in supply chain shortages.

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<sup>20</sup> See, e.g., Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources; Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74,702, 74,707 & 74,716 (Dec. 6, 2022).

Commenter (2326-AXPC) believes that EPA should set the demarcation date for new, modified, and reconstructed NSPS OOOOb as December 6, 2022. Briefly, the commenter believes:

- The November 2021 Notice did not meet the bare minimum requirements under CAA section 307(d) and APA section 553(b) to constitute a “proposed regulation” because a preamble without regulatory text is not a “regulation;” and
- Because the November 2021 notice was not a “proposed regulation,” it could not define a “new source” trigger date under CAA section 111(a)(2).

Commenter (2360-Devon Energy) encourages EPA to establish December 6, 2022, as the appropriate applicability date for new sources subject to NSPS OOOOb. The commenter contends that the initial proposal provided a general framework for regulating methane and volatile organic compounds (VOC) from new and existing sources but lacked the regulatory text necessary to provide the reasonable regulatory certainty necessary for oil and gas operators to be able to make operational and contractual decisions and procure the equipment necessary for compliance. The commenter states that contracts for services and equipment are often finalized months or years in advance, and without the benefit of regulatory certainty in the initial proposal, as evidenced by the numerous changes between the initial and supplemental proposals, operators are left to surmise what the final regulations will entail. The commenter notes that it is actively working toward operational practices and facility designs that meet or exceed the proposed standards, including the phase-out of gas-driven pneumatic controllers, but notes it is necessary that the proposed regulations allow for appropriate “new” and “existing” source designations (*i.e.*, when regulatory text is proposed) and allow for appropriate compliance timelines and control strategies (*e.g.*, routing gas-driven pneumatic controllers to combustion devices) that acknowledge the resource, supply chain, and time constraints that exist when modifying facilities and wells that are already producing in accordance to newly enacted standards.

Commenter (2399-GPA) requests that EPA revise the applicability date for NSPS OOOOb to be, at the earliest, December 6, 2022—the date EPA published the supplemental proposed rule in the *Federal Register*. The commenter asserts that EPA did not in fact propose the actual “regulations” when it provided an initial proposal in 2021 and that, without any actual rules to guide, as a matter of law and basic fairness, EPA should not seek to make November 15, 2021, the effective date for NSPS OOOOb.

First, the commenter (2399-GPA) argues that the CAA does not authorize EPA to make the effective date of NSPS OOOOb a year before it published the actual regulations. The commenter recognizes that in CAA section 111(a)(2) the definition of “new source” suggests that EPA may apply a “standard of performance” to a new source as of the date of “proposed regulations.”<sup>21</sup> However, the commenter states that the EPA did not publish a clear “standard of performance” in “proposed regulations” in November 2021 – it provided preamble language, requested comment on the numerous suggestions it outlined in that preamble, and promised to publish the actual regulatory text. The preamble, however, does not set a “standard of performance” and is not the governing “regulations,” but is designed to inform the public about the meaning of the

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<sup>21</sup> A “new source” is “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” 42 U.S.C. §7411(a)(2); CAA §111(a)(2).



regulations that are codified in the Code of Federal Regulations.<sup>22</sup> According to the commenter, it has long been understood that those explanatory statements are distinct from the actual rules – and would be used by the courts and the public “in the interpretation of the agency’s rules.”<sup>23</sup>

Second, the commenter (2399-GPA) notes that in putting together the supplemental proposed rule and preparing the regulatory text, EPA has added to and changed the approach it described in the November 2021 preamble.<sup>24</sup> The commenter states it would be grossly unfair and unsound policy for the agency to make a proposal retroactive, when sources and permit writers could not know even a general description of what EPA intended, let alone the regulatory text that would in fact govern. The commenter points to areas where EPA did not set suggested outcomes, such as the requirements for control devices on combustion sources. The commenter asserts that the general request for comments for additional monitoring for control devices does not mean that flow meters and net heating value measurements and other requirements would be required, as EPA has now proposed. Moreover, the commenter contends that unilaterally applying new regulatory text retroactively does not consider the practical implications, costs or burdens associated with retrofitting controls or monitoring equipment on existing controls in the segment.

Third, the commenter (2399-GPS) contends that EPA’s proposed November 2021 effective date runs counter to the U.S. Supreme Court’s long settled rule against applying law retroactively.<sup>25</sup> According to the commenter, nothing in the Act expressly provides EPA the authority to take the wholly unprecedented act of saying its preamble is sufficient. As such, by making NSPS OOOOb effective a year before EPA provided the public the regulatory text, it should be viewed as an impermissible retroactive application.<sup>26</sup>

Fourth, even assuming for the sake of argument that EPA had the authority to apply its December 6, 2022, proposed regulations to sources that commenced construction after November 11, 2021, the commenter (2399-GPA) believes EPA should not do so. The commenter

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<sup>22</sup> *E.g.*, 1 C.F.R. § 18.12 (“Each agency submitting a proposed or final rule document for publication shall prepare a preamble which will inform the reader, who is not an expert in the subject area, of the basis and purpose for the rule or proposal.”); see Administrative Conference of the United States, *Guidance in the Rulemaking Process: Evaluating Preambles, Regulatory Text, and Freestanding Documents as Vehicles for Regulatory Guidance* at 4 (May 16, 2014) (distinguishing preamble language a “agency statements outside of those appearing in regulatory text that pertain to the meaning or interpretation of the agency’s regulations or to advice about how to comply with the agency’s regulations”).

<sup>23</sup> United States Department of Justice, Attorney General’s Manual on the Administrative Procedure Act at 32 (1947). That was the governing principle underpinning the requirement in the Administrative Procedure Act to require a “statement of basis and purpose of rules issued,” so as to “with reasonable fullness explain the actual basis and objectives of the rule.” H.R. REP. NO. 79-1980, at 259 (1946); S. REP. NO. 79-752, at 201 (1945), as available in Administrative Procedure Act, Legislative History, 79th Cong., S. Doc. No. 79-248, 1944-46, 225 (1944-46). That statement is the explanation – not the “rule.”

<sup>24</sup> See, *e.g.*, Proposed Rule at 74,707 (summarizing changes made to Subpart OOOOb in response to comments received on the November 2021 Proposal).

<sup>25</sup> *Bowen v. Georgetown University Hospital*, 488 U.S. 204 (1988) (“Retroactivity is not favored in the law.”). Congress must convey “the power to promulgate retroactive rules” “in express terms.” *Id.*

<sup>26</sup> *E.g.*, *Marrie v. S.E.C.*, 374 F.3d 1196, 1207 (D.C. Cir. 2004) (“In the administrative context ... ‘a rule is retroactive if it ‘takes away or impairs vested rights acquired under existing law, or creates a new obligation, imposes a new duty, or attaches a new disability in respect to transactions or considerations already past.’”).

states that good policy should afford affected facilities fair notice of the actual regulations – the regulatory text – before potentially being subject to those requirements considering the extraordinary complexity of the proposed regulations – layered onto the already confusing history surrounding the past decade of regulation of oil and natural gas production, midstream, transmission and storage. Moreover, the commenter contends that in the supplemental proposal EPA has proffered no actual justification for adopting this unprecedented approach, making no effort to consider the impracticality, burdens and costs imposed on sources that had no actual regulatory text to consider – and to weigh those against any purported benefits of this harsh retroactive approach.

Commenter (2428-API) states that the new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the *Federal Register*. The commenter believes that not only does CAA section 111(a) allow EPA to define the new source trigger date based on the publication date of the supplemental proposal, but also in fact requires it. The commenter reiterates their comments on the original NSPS OOOOb and EG OOOOc proposed rule that the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, they believe that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule. The commenter provides that EPA’s analysis on the applicability date indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021, as the trigger date for new sources, but nothing in EPA’s analysis specifically concludes or determines that it must use the November 15, 2021, date. The commenter therefore believes that EPA’s rationale for using November 15, 2021, remains flawed for three reasons.

First, the commenter (2428-API) states that the CAA section 111(a)(2) definition of “new source” uses the term “proposed regulations” in defining the new source trigger date. The commenter notes that a preamble unaccompanied by regulatory text is not a “regulation.” Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. The commenter asserts that it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 supplemental proposal’s regulatory text. The commenter provides that, for example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. The commenter states that the EPA then abandoned the baseline emissions approach in the November 2022 supplemental proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that undergo liquids unloading that is not designed to eliminate venting. The commenter states that these co-proposals, while limited to a subset of the affected facilities, provides evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text. The commenter contends that the November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. The commenter asserts that the absence of proposed regulatory text in the

original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might apply, and thus prevents them from adequately planning for compliance.

Second, the commenter (2428-API) states that EPA's interpretation of CAA section 307(d) and APA section 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, the commenter notes that the EPA argues that the required content of a proposed rule specified in CAA section 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA sections 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. The commenter asserts that is nonsensical because the record for judicial review is limited to the materials prescribed by CAA sections 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA section 307(d)(7)(A). The commenter argues that if proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review, which is contrary to reason and the clear intent of the law. The commenter summarizes that it is simply not plausible to argue that because CAA section 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". The commenter maintains that when considered as a whole, CAA section 307(d) plainly requires rule text to be available.<sup>27</sup>

Third, and more broadly, the commenter (2428-API) contends that the rush issuance of the original proposed rule was politically motivated as a facet of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.<sup>28</sup> While the commenter recognizes that every administration has the right to set and implement its regulatory agenda they believe that this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. The commenter states that it would be unreasonable for affected facilities to bear the burden of those compromises. The commenter considers it arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, the commenter (2428-API) provides that nothing allows or requires EPA to utilize the November 15, 2021, date. Further, commenter states that the failure

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<sup>27</sup> EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

<sup>28</sup> EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA ("As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan. "With this historic action, EPA is addressing existing sources.")

of EPA to provide regulatory text in the November 15, 2021, proposal is reason enough for EPA to “warrant exercising” any discretion it does have with respect to the deadline.

Additionally, the commenter (2428-API) contends that by utilizing November 15, 2021, as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021, and December 6, 2022. The commenter explains that, for a significant number of the affected facilities, operators will be required to retrofit those new, modified, or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification, or reconstruction. Many of these requirements described by the commenter involve either: (1) substantial capital expenditures for equipment (*e.g.*, instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (*e.g.*, storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (*e.g.*, flow meters, calorimeters; and (4) substantial in-field resources for retrofits. The commenter asserts that not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, causes the rule to be much more costly for such sources than EPA predicts, and frustrates the regulatory purpose of setting the new source trigger date at the date of proposal (which they say clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification). The commenter also indicates the supply chain disruptions since the onset of the COVID pandemic and that the November 15, 2021, trigger date would only compound this issue.

Commenter (2483-INGAA) argues that application dates for NSPS OOOOb regulations governing new, modified, and reconstructed sources that commence construction after the date of the November 15, 2021, partial proposal, and that proposed EG OOOOc will govern existing sources that commenced construction on or before November 15, 2021, even for new sources subject to a previous NSPS (*i.e.*, NSPS OOOOa) are incorrect as a matter of law. The commenter notes that section 111(a) of the CAA defines a “new source” as “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.”<sup>29</sup> The commenter describes that EPA takes the position in the supplemental proposed rule that a notice of proposed rulemaking need not contain proposed regulatory language in order to trigger the applicability provision of CAA section 111(a). For support, EPA notes that a “notice of proposed rulemaking” is required to contain certain items under section 307(b) of the CAA and section 553(b)(3) of the APA, but neither explicitly requires regulatory language. The commenter contends that EPA ignores the text of section CAA 111(a), which does not refer to a “notice of proposed rulemaking” (the term used in section 307(b) to set minimum information that is required in such a notice) and instead 111(a) refers to “regulations ... or ... proposed regulations[] prescribing a standard of performance under this section.” (Emphasis added). The commenter adds that what the statute is referring to is plainly the actual rules – language that would become law and would be included in the Code of Federal Regulations once finalized – setting forth the standard of performance. According to the

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<sup>29</sup> CAA §111(a)(2), 42 U.S.C. §7411(a)(2).

commenter, if there is any doubt, the term “prescribing” dispels it: this term requires a level of specificity that cannot be set forth without regulatory text.

Moreover, commenter (2483-INGAA) highlights that section 111(a) of the CAA states that, after considering comments on the published “proposed regulations,” EPA “shall promulgate, within one year after such publication, such standards with such modifications as [EPA] deems appropriate.” This tight deadline for promulgating the final regulations that would legally prescribe conduct by the regulated entity reflects the highly unusual regime of regulation under section 111 – namely, that there may be some change between the date of the proposal and the final rule that may impose slightly different requirements on sources constructed in the interim, retroactively. The commenter states that it is unrealistic for EPA to be able to finalize regulatory language – which surely it must include in the final regulation – within one year of publishing a notice of proposed rulemaking that contains no proposed regulatory language whatsoever. The commenter considers this further evidence that EPA’s interpretation of the applicability date under section 111(a) is incorrect and unreasonable. According to the commenter, the date *should* be that of publication of specific proposed rules that prescribe a standard of performance, *not* that of a notice that generally describes a possible standard without prescribing it in detail. For these reasons the commenter contends that the application date for NSPS OOOOb is the date of the Supplemental Proposed Rule – December 6, 2022 – not the date of a notice of proposed rulemaking that contained no proposed regulations prescribing a standard of performance.

Commenter (2354-Business Roundtable) asserts that the EPA may define “new sources” based on the publication date of the supplemental notice, (*i.e.*, December 6, 2022). The commenter believes EPA is required to do so by the text of CAA section 111(a)(2). That section provides that new sources are those that were constructed, reconstructed or modified “after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section that will be applicable to such source.”<sup>30</sup> According to the commenter, the November 2021 proposal in this rulemaking contained no proposed “regulations” – *i.e.*, proposed regulatory text – it was simply a preamble.<sup>31</sup> The commenter notes that it is well-established in administrative law that “regulations” are the regulatory text that will appear in the Code of Federal Regulations. In *Perez v. Mortgage Bankers Ass’n*, for example, the Supreme Court declared that an interpretive rule cannot “amend” a “regulation” because a regulation is “text” in the CFR that can only be amended by notice and comment rulemaking.<sup>32</sup> “Regulations” are “agency statement[s] of general applicability and future effect, which the agency intends to have the force and effect of law.”<sup>33</sup> The commenter provides Justice Kavanaugh’s explanation, “[by] the 1980s, the words ‘regulation’ and ‘substantive’ ... carried a special meaning in the context of administrative law ... A ‘substantive rule,’ often promulgated pursuant to specific statutory authority, is a rule that ‘bind[s]’ the public or has ‘the force and effect of law.’”<sup>34</sup> By contrast, the commenter states that regulatory preambles do not appear in the CFR, and ordinarily are not legally binding.

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<sup>30</sup> 42 U.S.C. §7411(a)(2)

<sup>31</sup> See 86 Fed. Reg. 63110 (Nov. 15, 2021), referring repeatedly to “this preamble” (*e.g.*, at 63115, 63116).

<sup>32</sup> *Perez v. Mortgage Bankers Ass’n*, 575 U.S. 92, 103-105 (2015).

<sup>33</sup> See E.O. 12866 (Sept. 30, 1993) at § 3(d).

<sup>34</sup> *Azar v. Allina Health Services*, 139 S.Ct. 1804, 1818 (2019) (Kavanaugh, J., concurring)

According to the commenter (2354-Business Roundtable), because CAA section 111(a)(2) specifically refers to proposed “regulations,” the November 2021 proposal did not trigger it, and the applicability date for this rulemaking is therefore December 6, 2022, the date of publication of the supplemental notice, which does include proposed CFR text, albeit still not in the *Federal Register*.<sup>35</sup> The commenter states that EPA contends that CAA section 307(d)(3) enumerates all the required elements of a notice of proposed rulemaking (*e.g.*, factual data), and that these do not include proposed regulatory text.<sup>36</sup> In fact, this statutory enumeration spells out what belongs in the statement of basis and purpose, which is to “accompan[y]” the notice of proposed rulemaking.<sup>37</sup> Section 307(d)(6)(A) of the CAA sets almost exactly the same requirement for final rules, too,<sup>38</sup> which obviously must contain the CFR text of the final rule. The commenter concludes that Congress assumed EPA would publish the text in both cases.

Based on this analysis, the commenter (2354-Business Roundtable) believes CAA sections 111(a)(2) and 307(d) require EPA to set December 6, 2022, as the applicability date for this rulemaking. In addition to the statutory basis that establishes the applicability date on December 6, 2022, the commenter adds that the Agency has good reasons, rooted in the purpose of section 307(d) of the CAA, to exercise its discretion to do so due to the complexity and coverage of the rule. The commenter provides that EPA has recognized the sheer number of facilities to which the proposed regulations will apply and the complexity of the regulations.<sup>39</sup> The commenter contends that unnecessary complexity and regulatory confusion not only waste resources but also make it more difficult to comply with regulations designed to reduce methane emissions. By applying the definition of “new source” consistent with the CAA and setting the applicability date for NSPS OOOOb as December 6, 2022, EPA would clarify regulatory applicability to the benefit of both sources and the Agency. Additionally, the commenter states that sources affected by applying the correct applicability date (new, modified, or reconstructed sources between November 21, 2021, and December 6, 2022) would still be regulated. They would first be subject

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<sup>35</sup> The Agency argues that neither Section 307(d) of the Clean Air Act nor Section 553 of the Administrative Procedure Act (APA) requires EPA to publish the proposed C.F.R. text in a notice of proposed rulemaking. In fact, the D.C. Circuit has held that Section 307(d) does require EPA to publish proposed regulatory text. *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F. 2d 506 (D.C. Cir. 1983) involved a CAA rulemaking where, as here, EPA did not include the proposed regulatory text in its notice of proposed rulemaking. The court began by noting that, “[i]n 1977, Congress—concerned that the [APA] did not provide procedures adequate for the complex scientific issues involved in EPA rulemaking—created new procedures for most rulemaking under the CAA, [ones that] require[] a much more detailed notice of rulemaking.” *Id.* at 518. The court explained that one of the two major differences between APA §553(b) and CAA §307(d)(3) [is that] the CAA, unlike the APA, requires EPA to issue a “proposed rule.” Although CAA §307(d)(3) does not explicitly require EPA to issue a proposed rule, it refers to the agency’s duty to explain “the factual data on which the proposed rule is based” and “the major legal interpretations and policy considerations underlying the proposed rule.” *Id.* at 519.

<sup>36</sup> 87 Fed. Reg. 74716.

<sup>37</sup> 42 U.S.C. §7607(d)(3) (emphasis added)

<sup>38</sup> *Id.* §7607(d)(6)(A).

<sup>39</sup> Supplemental Notice, *supra* note 1 [87 Fed. Reg. 74702 (Dec. 06, 2022).], at 74833 (“The EPA understands that EG OOOOc for the Crude Oil and Natural Gas source category will apply to an extraordinary number of designated facilities and for many designated facilities the standards are complex compared to other EG. For example, in the U.S., the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities.”).

to existing NSPS OOOOa, and then in a few years, EPA's proposed EGs for existing sources under EG OOOOc, thus eliminating any potential regulatory gap.

Finally, the commenter notes that many thousands of wells and other equipment will become subject to the new source performance standards. The commenter contends it will be an enormous challenge for owners and operators to purchase and install the required equipment, establish record-keeping and reporting protocols, and train personnel needed to comply with these regulations just 60 days after the final regulations are published in the *Federal Register*. The commenter urges EPA to incorporate extended implementation timelines that phase-in compliance with the standards.

Commenter (2248-NDPC) reiterated their January 31, 2022, comments, where they commented that they do not believe this action (*i.e.*, the proposed rule in Docket EPA-HQ-OAR-2021-0317) meets the legal or ethical requirements of a proposed rule for rulemaking and the proposed applicability date for sources that will be subject to the new subpart NSPS OOOOb should not be November 15, 2021, but rather the date the actual proposed rule text is finally published. The commenter reports that several state agencies and other industry trades made the same comment. In addition, the commenter notes that the additional information requests in this supplemental proposal have put a large burden on state agencies, the public, and the industry to provide meaningful comments on such a moving target. The commenter contends that this is setting a dangerous precedent for future regulation development and public participation. The commenter is requesting the EPA rethink its position on calling this a proposed rule and not set the effective date until all stakeholders have a chance to review a complete, well-written proposal.

Response II-3-1: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

Comment: Commenter (2218-Texas Commission on Environmental Quality and Railroad Commission to Texas) notes that the new NSPS has different applicability and modification definitions than the NSPS OOOOa rule. The commenter suggests that creating separate classifications within the NSPS based on dates of construction or modification will create additional burdens when reviewing authorizations within the specified legislatively mandated time frames. In the preamble, the commenter reports that the EPA provided different scenarios to demonstrate how applicability under the different rules would work. The commenter appreciates the examples EPA provided in the preamble demonstrating how applicability under the different rules would work, however, they assert that the fact that the provided examples are needed demonstrates the complexity of these overlapping requirements.

Response II-3-2: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

Comment: Commenter (2337-Kansas Department of Health and Environment) indicates that there were significant changes and updates made to the November 15, 2021, original rule proposal. These include different designated (affected) facility categories, their corresponding proposed BSER/EG (and frequency and methods of monitoring), and most importantly, the basis for such amendments (*e.g.*, assumptions, modeling approach, analysis) in such a way that the

SNPR proposal is almost a complete overhaul of the original rule proposal. The commenter believes it makes sense that the definition of "new source" be based either on the date after the publication of the SNPR or, since the EPA is still in the process of soliciting comments on all important aspects of the supplemental proposal, to wait until after the publication of a final draft of the rule.

Response II-3-3: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

### **3.2 Existing Source for Purposes of the Proposed EG OOOOc**

Comment: Commenter (2483-INGAA) agrees with EPA's definition of "existing source" and states that the statutory text is unambiguous, and therefore a source cannot be both "new" and "existing" at the same time. The commenter notes that even so, EPA insists that the applicability date of EG OOOOc for existing source methane standards is for sources that commenced construction on or before November 15, 2021 (*i.e.*, the applicability date after which the NSPS OOOOb new source standards apply). Recognizing that under this regime a source that was constructed after September 18, 2015 (the applicability date for the NSPS OOOOa new source standards) would be subject simultaneously to NSPS OOOOa and EG OOOOc, EPA goes on to explain how it believes the two standards would interact and which standard would govern for which type of source. Thus, according to EPA – though the commenter notes the Agency never says it explicitly – such sources are both "new" because they were constructed after the applicability date of NSPS OOOOa and "existing" because they were constructed before the applicability date of NSPS OOOOb. The commenter contends that the statutory text cannot bear such an interpretation.

The commenter (2483 - INGAA) states that the statute defines "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source."<sup>40</sup> Sources whose methane emissions were subject to NSPS OOOOa are "new sources" under section 111 – and thus they cannot be existing sources – because those sources are already subject to "a standard of performance" for methane under section 111. As a result, "existing sources" for the purpose of proposed EG OOOOc are those sources that commenced construction on or before September 18, 2015, which is the date that NSPS OOOOa was proposed. According to the commenter, any source that commenced construction after that date was a "new source" and complied with the standards of performance set forth in NSPS OOOOa.

The commenter (2483-INGAA) believes that this makes sense within the context of section 111(d) of the CAA, which is to ensure that certain pollutants (those like methane that are not regulated under the national ambient air quality standard (NAAQS) program or the hazardous air pollutants (HAP) program) are regulated either as new sources under CAA section 111(b) or as existing sources under CAA section 111(d).<sup>41</sup> The commenter holds that there is no need to

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<sup>40</sup> CAA §111(a), 42 U.S.C. §7411(a).

<sup>41</sup> See *id.* §111(d), 42 U.S.C. §7411(d).



regulate sources that commenced construction after September 18, 2015, under the existing source program of CAA section 111(d) because those sources have already complied with NSPS under CAA section 111(b). For these reasons, the commenter recommends EPA change the applicability date for EG OOOOc to sources that commenced construction on or before September 18, 2015.

Response II-3-4: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

Comment: Commenter (2254-PBPA) states that existing source standards should not be “co-proposed” with new source standards, as EPA has done here, but should instead be informed by already-finalized new source standards and made less stringent as necessary to accommodate “other factors,” such as the remaining useful life of existing sources.<sup>42</sup> The commenter notes that EPA has previously proposed to require that existing source standards be proposed simultaneously with new source performance standards, but EPA ultimately declined, in part because “proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance” would allow “the Agency [to] benefit from the comments on the standard of performance in developing the emission guideline.”<sup>43</sup> If EPA proceeds as proposed, the commenter suggests that the opportunity to have the EG informed by the process of developing and implementing the NSPS would be lost. According to the commenter, this would have material consequence because EPA would be left to take a one-size-fits-all approach through enacting existing source standards that largely mirror its new source standards. The commenter states this is particularly important because EGs will have a far greater impact on the oil and gas sector because there are far more existing sources than there are new sources subject to the NSPS program.

Additionally, commenter (2254-PBPA) provides that EPA should wait and later propose EGs that are less stringent than the proposed NSPS under NSPS OOOOb because there are a fundamentally different set of considerations when regulating existing sources for the first time. Existing sources must retrofit equipment without the benefit of incorporating emission controls into pre-operational design, resulting in added costs. For example, the commenter provides that in the Permian and many other areas, many existing well sites are low producing wells that could be close to production cycle end-of-life. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production. These costs will likely accelerate the abandonment of many older existing well sites by fundamentally altering the costs associated with their operations and ongoing compliance. The commenter states that the economics of EPA’s proposed EGs are therefore fundamentally different and more burdensome to the industry than new source standards, and EPA needs to revise its economic analysis accordingly.

Response II-3-5: EPA disagrees with commenters that the Agency was required to first promulgate final NSPS before proposing to promulgate Emission Guidelines. Nothing in CAA

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<sup>42</sup> 42 U.S.C. §7411(d)(1). EPA should not, as it has proposed, require states to demonstrate as a threshold matter that a designated facility cannot reasonably apply BSER before the states account for remaining useful life and other factors (RULOF) in order to set a less stringent standard. See 87 Fed. Reg. at 74,820-21.

<sup>43</sup> See, e.g., 40 Fed. Reg. at 53,345.

section 111(d) requires that the EPA take these actions consecutively rather than concurrently. Rather, CAA section 111(d)(1) provides that the Administrator “prescribe regulations” pursuant to which states develop plans that “establish[] standards of performance for any existing source for any air pollutant ... (ii) to which a standard of performance under this section would apply if such existing source were a new source.” For each existing emission source addressed by the final Emission Guideline, the EPA is also finalizing an NSPS that would apply “if such existing source were a new source.” Accordingly, EPA has satisfied the requirements of CAA section 111(d). For EPA’s response to comment regarding the different factors that may affect the EPA’s identification of the BSER for existing sources, see section XIII.C.1 of the final rule preamble.

Comment: Commenter (2391-Chesapeake Energy Corporation) recommends that if the final rule does not authorize compliance by routing natural-gas driven pneumatic controllers and pumps to control devices, EPA should define “new sources” based on the December 6, 2022, publication date of the supplemental proposal to allow them and other similarly situated operators more time to plan for and attain the zero emission standards proposed for existing sources under EG OOOOc. Alternatively, the commenter suggests EPA employ any available authority it has to provide operators like them who may need to comply with standards for modified or reconstructed sources a more reasonable and feasible amount of time to determine applicability and implement the final regulation.

Response II-3-6: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

### **3.3 EG OOOOc Impact on Existing NSPS KKK, NSPS OOOO, or NSPS OOOOa**

Comment: Commenters (2180-Pennsylvania Department of Environmental Protection (PADEP), 2222-Wisconsin Department of Natural Resources (WIDNR), 2301-U.S. Chamber of Commerce (USCC)) recommend that EPA streamline requirements in consideration of the complex implementation requirements of this rule compounded with existing regulation requirements.

Commenter (2180-PADEP) requests that EPA consolidate existing applicable regulations and streamline the proposed requirements for new and existing sources in the oil and natural gas industry. The commenter contends that with multiple regulations, operators could miss important requirements, which would consequently increase the burden on state regulators in determining and enforcing compliance. The commenter notes that the regulatory framework becomes even more complex when considering state regulations that were promulgated to comply with the State Implementation Plan (SIP) requirements for the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry (2016 CTG).

The commenter (2180-PADEP) states that, because EPA intends to promulgate a NSPS and an EG for existing sources in the oil and natural gas sector, the proposed rules should be modified to include all applicable existing requirements and replace NSPS KKK, LLL, OOOO, and OOOOa, while also establishing appropriate VOC and methane requirements for existing sources. The commenter maintains that streamlining the regulatory requirements by allowing both the industry and state regulators to determine regulatory applicability based on a singular date would be an

efficient approach that would enable states to then streamline their regulations for the oil and natural gas industry when submitting their SIPs to comply with the EG.

Commenter (2222-WIDNR) indicates that the complexity of determining applicability of multiple CAA section 111 standards to the same group of equipment at a facility is burdensome for affected sources and permitting authorities and ultimately leads to inconsistencies in rule implementation. The commenter contends that for certain designated facilities, the presumptive standards that will apply to existing facilities under the proposed EG are less stringent than standards that apply to those facilities under existing NSPS KKK, OOOO, or OOOOa. The commenter suggests that for designated facilities that are subject to a more stringent NSPS limit than the limit proposed in the EG, EPA should include in the EG (or at the very least in the federal plan implementing the EG) a limit equivalent to the NSPS limit for designated facilities constructed within the applicability time frame of the NSPS. Additionally, the commenter provides that for certain designated facilities, EPA proposes in its preamble that compliance with the EG will satisfy compliance with the existing NSPS. The commenter also states that EPA should ensure rule language to this effect is included in the EG so this decision is clear and enforceable, and that EPA should revise the titles and applicability conditions in the existing NSPS KKK, OOOO, and OOOOa to clarify which rules facilities must comply with.

Commenter (2301-USCC) provides that EPA must avoid complex and difficult-to-follow layering of multiple NSPS regimes atop one another, particularly for equipment located at the same site. EPA must ensure that the regulatory regime does not require extensive time and resources to track differing compliance requirements for equipment across these facilities and should aim instead to align any new requirements with those already in place under the existing regime or continue to clearly state in the final regulatory text that compliance with any NSPS or EGs finalized under this rulemaking will also constitute compliance with the older NSPS standards.

In particular, the commenter (2301-USCC) notes that sources already subject to NSPS OOOOa as of EPA's proposed November 15, 2021, applicability date,<sup>44</sup> also become existing sources on that date, and therefore subject to EG OOOOc requirements.<sup>45</sup> The commenter notes that adding to this already complicated structure, different pieces of equipment at the same facility would be subject to different versions of the NSPS based on whether the individual component was replaced or modified after a particular trigger date, which would require extensive tracking for operators to determine which regime applies to each piece of equipment if EPA does not make compliance with the new standards equate to compliance with NSPS OOOO and OOOOa. However, the commenter asserts that EPA's Methane Proposal would not fully abrogate NSPS OOOO and NSPS OOOOa, indicating only that "[f]or most designated facilities," compliance with an implementing state or federal plan consistent with EG OOOOc would constitute compliance "with the older NSPS," presumably meaning NSPS OOOO and OOOOa.<sup>46</sup> The commenter contends that this would not provide sufficient regulatory certainty for regulated

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<sup>44</sup> Although, as noted in other sections of the comment letter, the commenter contends that the proper applicability date for any final rule should be the date of this proposed Methane Proposal—December 6, 2022—not that of the November 2021 Notice.

<sup>45</sup> See 87 Fed. Reg. at 74,707 (Table 1 providing applicability dates for NSPS OOOOa and EG OOOOc).

<sup>46</sup> Id. at 74,707.

sources under the Methane Proposal. The commenter asserts that regulated entities should not be left to guess whether they will be found in compliance with the proposed layering of requirements—particularly given the potential to incur high administrative and civil penalties on a per-day, per-violation basis in the event of an enforcement case. According to the commenter, the resulting web of regulatory requirements would not only be arbitrary and capricious and unduly burdensome but would also raise serious due process concerns. The commenter recommends EPA simplify the application of these layered provisions to remedy these due process and CAA concerns.<sup>47</sup>

Response II-3-7: In this action the EPA is finalizing amendatory text to NSPS KKK, OOOO, and OOOOa to state that those rules continue to be in effect until an affected facility begins complying with a more stringent requirement, that applies to the same affected facility, in an approved, and effective, state or federal plan that implements EG OOOOc, or modifies or reconstructs to become subject to NSPS OOOOb. With the exception of sweetening units at onshore natural gas processing plants, all affected facilities under NSPS KKK, OOOO, and OOOOb have corresponding designated facilities under EG OOOOc, however, the emissions standards for sweetening units remain unchanged from NSPS LLL to NSPS OOOO, OOOOa, OOOOb or OOOOc. For further information, see section IX.C of the final rule preamble.

Comment: Commenters (2326-AXPC, 2428-API) question the legality of simultaneous designations as a “new” and “existing” source under multiple standards.

Commenter (2326-AXPC) states EPA must clarify that where overlapping NSPS requirements apply to a source, the source needs to comply with only one set of requirements. The commenter notes that generally, EPA suggests that one must conduct a line-by-line comparison of the requirements from each of the multiple applicable regulations to determine which is most stringent, and EPA will consider compliance with the most stringent to be compliance with the other applicable regulations. The commenter provides that there will of course be uncertainty as to whether one requirement is more stringent than another. For example, if a similar standard requires methane and VOC reductions on the one hand and only methane reductions on the other, which is more stringent? In addition to this uncertainty, the commenter provides that the EPA does not explain how operators must sort through the reporting and recordkeeping requirements under multiple standards that would apply simultaneously. Must the operator report under both standards? The commenter further states that EPA provides no legal analysis for why it believes a source could be subject to multiple, conflicting performance standards as a “new” source under one standard and an “existing” source under another. The commenter is not aware that EPA has ever taken the position that a source could continue to be subject to a previously applicable new source performance standard after triggering the applicability of a subsequent standard. And here, EPA proposes that EG OOOOc will apply to existing sources regardless of whether the source is subject to NSPS OOOO or OOOOa. The commenter requests that EPA clearly identify that only one NSPS OOOO/a/b/c standard can apply to a source at any given time. The commenter recommends EPA provide detailed affected facility-by-affected-facility guidance, on

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<sup>47</sup>*Cf. Sessions v. Dimaya*, 138 S. Ct. 1204, 1212 (2018) (“‘The prohibition of vagueness in criminal statutes’ . . . is an ‘essential’ of due process, required by both ‘ordinary notions of fair play and the settled rules of law.’ The void-for-vagueness doctrine, as we have called it, guarantees that ordinary people have ‘fair notice’ of the conduct a statute proscribes.... And the doctrine guards against arbitrary or discriminatory law enforcement.”).

a requirement-by-requirement basis, that clearly identifies the applicable compliance standard, along with guidance on recordkeeping, reporting, and notification requirements should the current proposal be finalized.

Commenter (2428-API) expresses that the explanation provided at 87 FR 74716 does not provide sufficient detail on key legal questions of this application. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a “new” source under a prior NSPS and, at the same time, be regulated as an “existing” source under a subsequent CAA section 111(d) program. The commenter contends this is how EPA considers the law to work, but that the supplemental proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

The commenter (2428-API) notes that EPA has never taken the position that previously applicable NSPS continue to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both NSPS OOOO and OOOOa. It is easily conceivable that a given storage vessel might have triggered NSPS OOOO because it was constructed one month after that standard was proposed and then subsequently triggered NSPS OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the NSPS OOOO storage vessel requirements cease to apply after the corresponding NSPS OOOOa requirements are triggered. The commenter asserts that the approach to reconciling applicability suggested in the supplemental proposal cannot be reconciled with EPA’s historic practice.

More broadly, the commenter (2428-API) provides that EPA fails in both the original and supplemental proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as NSPS OOOO) and then triggers a subsequent version of that new source standard (such as NSPS OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as NSPS OOOO or OOOOa) and is in existence when a subsequent CAA section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a CAA section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb). In sum, the commenter believes EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA section 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). The commenter notes the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

Response II-3-8: Section IX (Interaction of the Rules and Response to Significant Comments Thereon) of the preamble to the final rule responds to these comments.

Comment: Commenter (2177-Southern Ute Indian Tribe) states that the current set of proposed regulations, EG OOOOc do not directly impose requirements on existing sources. Rather, states must submit plans for the EPA's approval that are at least as effective as the presumptive standards in EG OOOOc. The commenter explains that many states already have oil and gas emission control programs in place, and the EPA has outlined criteria to assist those states in determining whether those existing programs are equivalent to EG OOOOc. The commenter contends that this approach leaves sources located in Indian country in uncertainty as these sources are not under state regulation. The commenter suggests EPA consider developing reservation specific Federal Implementation Plans (FIP) or assist tribes with developing Tribal Implementation Plans (TIP) for sources located within Indian country. The commenter notes EPA proposes to require states to submit their methane plans for review within 18 months of publication of the final EG and to require compliance by existing sources within 36 months after the state plan is due to the EPA. The commenter suggests EPA should consider the timeliness of FIP and/or TIP development to coincide with state plans.

Response II-3-9: See the discussion in Section I.A (General Information/Does this action apply to me?) ((of the preamble to the final rule. Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing sources. The EPA notes that this final rule does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes.

Comment: Commenter (2286- Colorado Department of Public Health and Environment, Air Pollution Control Division) appreciates EPA's narrative discussion comparing the older NSPS to the proposed presumptive standards but requests that EPA include the described more stringent provisions in the proposed presumptive standards directly or by reference, should EPA prefer those requirements continue to be implemented instead of the proposed presumptive standards once finalized. Specifically, the commenter requests that EPA put forth a singular standard for gas plant leak detection and repair (LDAR) to streamline oversight and reduce uncertainty in the various applications of portions of federal rules. The commenter appreciates the goals that EPA is pursuing with this proposal. However, the commenter requests that EPA not err on the side of being overly prescriptive and allow states flexibility in determining appropriate criteria on these issues to allow for the continued implementation of effective plans.

Response II-3-10: See the discussion in Section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa) of the preamble to the final rule.

Comment: Commenter (2393-Oklahoma Office of the Secretary of Energy and Environment) indicates that EPA has made a few notable exceptions for when the existing standards may functionally be more stringent than the new EGs and therefore must continue to be followed. Namely, EPA mentions that NSPS KKK is more stringent than the presumptive standard in EG OOOOc for centrifugal compressors and reciprocating compressors.<sup>48</sup> The commenter states that this would mean that some facilities could be subject to requirements of both NSPS KKK and EG OOOOc. In addition, EPA's change from regulating a single storage vessel in NSPS OOOO

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<sup>48</sup> 87 Fed. Reg. 74717.

and OOOOa to regulating a tank battery in EG OOOOc and from a pneumatic controller in NSPS OOOO and OOOOa to a collection of pneumatic controllers in EG OOOOc further complicates the determination of what facilities are subject to which regulations.<sup>49</sup> The commenter asserts that regulations need to be clear as to which subpart equipment was subject to along with when and how a source became subject to a different regulation.

Response II-3-11: See the discussion in Section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa) of the preamble to the final rule.

Comment: Commenter (2428-API) states that EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the supplemental proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. The commenter notes EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. The commenter contends that these difficulties for the regulated community have been compounded by other rules that impact the same sources (*e.g.*, Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, the commenter requests EPA be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc.

Response II-3-12: Regarding the applicability date, see the discussion in Section IX.A. (What date defines a new, modified, or reconstructed source for the purposes of the final NSPS OOOOb?) of the preamble to the final rule. Regarding requests for comment extensions, see Responses II-23-20 and II-23-22 of Volume II, Chapter 23 (Miscellaneous Other Comments), subsection 23.4.1 (Public Comment Period Adequacy (*i.e.*, Request for Extension, Inadequate Time Provided) of the RTC. For the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc, see the discussion in Section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa) of the preamble to the final rule.

### **3.4 Feasibility of Applicability and Compliance Dates for New and Existing Sources**

Comment: Commenters (2200-NuEnergy Operating, Inc. (NuEnergy), 2227-WEA, 2252-PAW, 2255-Ovintiv Inc. (Ovintiv), 2428-API) express concerns with the ability to immediately implement the necessary changes within the proposed timeframes.

Commenter (2200-NuEnergy) states that implementation would not be feasible if a November 15, 2021, application date is set. The commenter indicates they would need many months' time for their company to comply with the new regulations. The commenter recommends an alternative scalable implementation timeline instead as they have no doubt that resources,

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<sup>49</sup> Id.

services, and equipment will not be immediately available to be able to comply with the new regulations.

Commenter (2227-WEA) recommends a phase-in period of three years for new and modified facilities to install equipment required to meet a non-emitting standard, and a longer period of seven years for existing facilities to retrofit equipment with low-bleed, intermittent bleed, or non-emitting controllers. The commenter states that EPA has not adequately considered the impacts of the current supply chain interruptions on the ability for operators to comply with the rule. The commenter notes that specialized equipment, such as air compressors, electric controllers, and equipment needed to retrofit facilities have been particularly hard-hit by supply chain constraints related to COVID-19. According to the commenter, the industry has experienced delays of several months in acquiring equipment to retrofit facilities, all prior to this publication being made. The increased demand for equipment, given the potential rule requirements, would only exacerbate the challenges associated with acquiring that equipment.

Commenter (2252-PAW) states that the CAA suggests compliance for NSPS sixty days following the final rule publication in the *Federal Register*, or sixty days after becoming an affected facility. The commenter does not believe this timeline is feasible for several emission source categories, including pneumatic controllers and pneumatic pumps. According to the commenter, nearly fifty percent of Wyoming surface and two-thirds of its mineral estate is federally managed. Most of the companies operating in Wyoming operate with a federal nexus, which in part include BLM wildlife stipulations including for sage grouse, burrowing owl, and ferruginous hawk. These stipulations restrict companies from conducting various construction activities due to disturbance thresholds such as noise. The commenter adds that during colder winter months, there could be weeks with temperatures below freezing when companies are unable to safely disconnect production facility equipment to retrofit with the necessary upgrades without wells and equipment freezing. With the existing supply chain and labor shortages, they note that it is expected that challenges will continue with both contractor availability and equipment availability. This necessitates a longer duration compliance timeline than currently being offered. The commenter requests that a location have a minimum of 18 months to bring a facility into compliance once rule applicability has been triggered.

Commenter (2255-Ovintiv) emphasizes the importance of providing adequate implementation time-periods in the final regulation. The commenter provides that it is already experiencing noticeable delays in the supply chain for various equipment required by the proposed rules including, but not limited to, control devices, flow monitoring equipment, and instrument air systems. The commenter asserts that these and other realities should be reflected in the implementation schedule in the final rule.

Commenter (2428-API) provides that NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. The commenter notes that the industry is already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to 4 months, while flow monitors are on backorder for a minimum of 6 to 8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year



on backorder, and recently ordered solar panels are delayed between 18 to 24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the commenter expects that the above timelines will be exacerbated before the market experiences a correction to meet these new levels of demand. The commenter requests EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, the commenter recommends EPA allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

Response II-3-13: The EPA considered these and other comments when establishing applicability and compliance dates in the final NSPS OOOOb and EG OOOOc rules. has revised the applicability and compliance dates.

For the NSPS OOOOb, the EPA has concluded that only sources constructed, modified, or reconstructed after the date of the Supplemental Proposal (December 6, 2022) should be considered new sources for the purposes of NSPS OOOOb. Changing this date to December 6, 2022, from the November 15, 2021, reduces the number of existing new sources that will need to comply with NSPS OOOOb, thereby allowing more time to plan for compliance and supply chain issues. The EPA believes that the adjustment to the applicability date from November 15, 2021, to December 6, 2022, gives sources an additional almost 13 months to plan and obtain equipment necessary to comply with the final rule . For details, please see discussion in section IX (Interaction of the Rules and Response to Significant Comments Thereon), subsection A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the final rule preamble. The EPA has also provided an alternative compliance timeline in the NSPS OOOOb final rule for process controllers and pumps required to meet a zero-emission standard (*i.e.*, final rule allows up to one year from the publication date of the final rule). See section XI.D.4 (Compliance dates) of the final rule preamble for a discussion on the compliance dates finalized for process controllers (which also applies for pumps).

For the EG OOOOc, the EPA is finalizing a compliance timeline of 36 months from the deadline for state plan submittals, which provides owners and operators of designated facilities time to plan for compliance and supply chain issues. When the compliance timeline of 36 months is considered in conjunction with the state plan submittal deadline of 24 months, that means that sources could have up to 5 years between when the EG are final and when they are required to fully comply with the applicable standards of performance. The EPA believes that any concerns with possible equipment or staffing shortages, which commenters speculate could be an issue, would likely be addressed by industry and regulators in that timeframe. See section XIII.E.3 (Compliance timelines) of the final rule preamble for EPA's response to comments regarding the compliance timeline required under the EG.

### **3.5 NSPS Compliance Dates**

Comment: Commenter (2351-Jonah Energy LLC (Jonah)) notes that it is their understanding that the compliance date for the NSPS is 60 days following the final rule publication in the *Federal Register*, or 60 days after becoming an affected facility. For several emission source categories, including pneumatic controllers and pneumatic pumps for example, the commenter states

compliance implementation within 60 days may not be physically feasible. The commenter reports that they operate on federal lands, and the BLM has wildlife stipulations, such as greater sage grouse, burrowing owl, and ferruginous hawk, which restrict them from conducting various construction activities during these stipulation times.

Additionally, the commenter (2351-Jonah) explains that during the 6 winter months in Wyoming, there could be weeks with temperatures below freezing when it becomes unsafe to disconnect production facility equipment to retrofit with the necessary upgrades without wells and equipment freezing. The commenter states that with the existing supply chain and labor shortages, they can expect challenges with both contractor availability and equipment availability that necessitates a longer duration compliance timeline.

Similarly, commenter (2305-Williams Companies, Inc. (Williams)) recommends the EPA modify the rule applicability date and provide flexibility with the compliance deadlines set forth in the proposed regulations (both the NSPS and EG) to account for the existing delays experienced in the industry due to labor shortages and equipment availability/supply chain issues.

Commenters (2257-Michigan Oil and Gas Association (MOGA), 2305-Williams) state that equipment supply issues, which have already been experienced by the commenter, have not been factored into the timeline for compliance with the proposed standards. Commenter (2257-MOGA) states that they spent considerable time contacting equipment manufacturers regarding the development of new replacement equipment similar to the existing devices (Ex.: process control valves, level controllers) and found it often takes 3 to 4 years to design, fabricate, test and certify new equipment. The commenter provides that this process does not account for the future manufacturing, purchase, delivery, installation, operational cycles and assessment of whether the new equipment meets the new standards. If the equipment falls short of expectations, the field operators may require delivery of replacement parts, modification kits, component change-out or total abandonment until the manufacturer can isolate the problem, redesign the device, and manufacture the new replacement parts, which begins the evaluation process all over.

Another commenter (2305-Williams) states that the EPA did not factor in the realities of the current supply chain delays and cost increases for the equipment and devices necessitated by the NSPS OOOOb/EG OOOOc regulations. The commenter notes that they have experienced significant supply chain and manufacturing delays since 2020 and they are not alone in this dilemma and difficult circumstances. The commenter reports that these delays can add a few months or up to a couple of years to a project or repair schedule depending on the equipment needed. The upgrades and modifications that will take place nationwide and across the entire industry will only add more strain to an already strained supply chain. Through no fault of an operator, they explain that timely installation or compliance may not be possible due to an inability to obtain the necessary equipment and or have that equipment operational by the extended compliance date. The commenter recommends the EPA modify the rule applicability date and provide flexibility with the compliance deadlines set forth in the proposed regulations to account for the existing delays experienced in the industry.

Response II-3-14: The EPA has considered these and other comments on concerns related to supply chain issues when developing the final rule requirements under NSPS OOOOb and EG OOOOc. For example, the EPA has included repair and delay of repair provisions that consider supply chain issues, and as discussed under Response II-3-13 of this Chapter, revisions to the applicability and compliance timelines provide for sufficient time to plan for compliance and supply chain issues.

### **3.6 Applicability-Related Definitions/Clarifications**

Comment: Commenter (2210-LANXESS Corporation) states that the “Crude Oil and Natural Gas Production source category” is defined within 40 CFR 60.5430 and 40 CFR 60.5430a. The commenter requests that, to add regulatory certainty of the source category being regulated under NSPS OOOOb, EPA should also add a similar definition to 40 CFR 63.5430b.

Response II-3-15: The December 2022 Supplemental Proposal NSPS OOOOb defined the “Crude oil and natural gas source category” and the definition is finalized as proposed.

Comment: Commenter (2416-Alyeska Pipeline Service Company (APSC)) considers the proposed rule to be somewhat ambiguous in defining the demarcation between natural gas transmission and downstream users, including local distribution companies and industrial end users. First, the commenter contends there is a lack of consistency in the “Am I subject to this subpart?” between 40 CFR 60.5365 and 60.5365a (NSPS OOOO and OOOOa) with the similar provisions proposed in NSPS OOOOb and EG OOOOc. The provisions in NSPS OOOO and OOOOa include the phrase “that is located within the Crude Oil and Natural Gas Production source category, as defined in...” while NSPS OOOOb and EG OOOOc do not include a comparable phrase for this source category. The commenter states that a comparable phrase would be helpful to the regulated community because it indicates the scope and extent of the rule. The commenter suggests that the language in 40 CFR 60.5365b and comparable language in 40 CFR 60.5365c be added as follows:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (l) of this section, that is located in the crude oil and natural gas source category, for which you commence construction, modification, or reconstruction after November 15, 2021.

Additionally, the commenter (2416-APSC) provides that the definition of “Crude oil and natural gas source category” is vague for purposes of part (2) of the definition. The commenter notes that while there is some improvement in the understanding of the “crude oil and natural gas source category” through the reading of the definition for “natural gas transmission”, the definition is inadequate because it does not clearly demarcate the distinction between gas transmission/gas distribution and local distribution or industrial end user. The commenter recommends that EPA examine the definition of the “Natural Gas Transmission and Storage Segment” found at 40 CFR 60.5430 and 60.5430a. The commenter believes the text in that definition provides better clarity on the demarcation between gas transmission/distribution and the end user.

Regarding “Natural gas transmission and storage segment,” the commenter (2416-APSC) states that, for the purposes of the related subpart, natural gas enters the natural gas transmission and storage segment after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage segment after the point of “custody transfer”. A compressor station that transports natural gas prior to the point of “custody transfer” or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage segment.” The commenter considers this definition to be important because it provides clarification to the natural gas transmission definition and the extent of the rule applicability for downstream facilities or sources. During the 2015 rulemaking of the NSPS OOOOa rule comments were made by the commenter and others to show that there are large commercial end users downstream of what is traditionally considered natural gas transmission, and EPA modified the definition of natural gas transmission and storage segment to exclude equipment that is used to deliver the natural gas to the end user and equipment used by the end user. Additionally, the commenter states that the natural gas transmission and storage segment definition is also consistent with the U.S. Department of Transportation definition of transmission line under 49 CFR 192.3, which reads:

*Transmission line* means a pipeline, other than a gathering line, that:(1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center...

The commenter (2416-APSC) suggests that if no changes are made, then a discussion in the final rule’s preamble would help the regulated community better understand the distinction between natural gas transmission and downstream facilities and end users.

Response II-3-16: The EPA agrees that, while the definitions section clearly defines the boundaries of the source category, additional clarification in the applicability section, in particular with respect to LDC custody transfer, would further help sources to identify if they might be subject to any of the requirements in NSPSs OOOOa and OOOOb and EG OOOOc. Therefore, these rules have been revised to include the following introductory language at 40 CFR 60.5365a and 60.5386c, as well as 40 CFR 60.5365a:

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section, that is located within the Crude Oil and Natural Gas source category, as defined in §60.5430b [or 40 CFR 60.5430a and 60.5430c, as relevant], for which you commence construction, modification, or reconstruction after September 18, 2015, and on or before December 6, 2022. Facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

Comment: Commenter (2428-API) recommends that EPA clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking. Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and OOOOa:

*Crude oil and natural gas source category* means:

- (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
- (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

The commenter points out that in footnote “301” (87 FR 74833), EPA states:<sup>301</sup>

For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA’s focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the “city-gate”.

The commenter (2428-API) does not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and requests that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

Response II-3-17: See Response II-3-16 of this Chapter.

### **3.7 Exemptions and Opt-in Provisions**

Comment: Commenter (2428-API) states that sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. The commenter believes this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, the commenter seeks clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. The commenter does not believe it is EPA’s intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, the commenter (2428-API) notes that some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example the commenter provides is under Pennsylvania’s § 127.11a. *Reactivation of sources*, which allows: “*a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied...*”. The commenter states that EPA already has included language addressing this concept as it pertains to storage vessels. The commenter believes EPA should extend this concept to all affected and designated facilities. The commenter suggests that if a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

Response II-3-18: The EPA recognizes that when an entire site or some equipment is shut-in, depressurized, and not in operation, that there will likely be no routine emissions. In accordance, the emission source specific standards apply only during times when an affected facility is in operation and does not apply at sites that are shut in and depressurized such that no gas is routed to the affected sources. However, the requirements contained in 40 CFR 60.5370b(b) apply during these periods. Specifically, these requirements include “[a]t all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.”

If a site or equipment that has been out of service is placed back into service, this would not constitute a modification unless a physical change occurred during the shutdown that results in an increase in emissions from the period prior to the shutdown, or if the equipment was operated in a manner differently from prior to the shutdown (*i.e.*, an “operational change”) that results in increased emissions.

However, EPA disagrees that additional time should be allowed for compliance prior to the affected facility being put back into service. Owners and operators are fully aware of the requirements that apply and should plan accordingly for the equipment to be in full compliance upon re-start.

Comment: Commenter (2399-GPA) recommends that EPA include provisions in the final rule that would allow and facilitate those owner and operators that have existing affected facilities covered by NSPS OOOOa to opt-in to NSPS OOOOb requirements for some or all their facilities that are presently covered by NSPS OOOOa. The commenter states that this would be a voluntary measure for those owner/operators who wish to comply with what EPA determines in its final NSPS OOOOb regulation to be the current BSER for their facilities and that those owner/operators would opt-in because they are committed to achieving the reduced emissions and improved level of environmental performance that EPA would expect from implementing the expanded emission controls and other requirements in the latest BSER in NSPS OOOOb. The commenter provides that it would also facilitate the work of regulators overseeing and permitting those facilities, which could otherwise have different requirements at the same location with some equipment subject to NSPS OOOOa and some to NSPS OOOOb, if certain affected facilities are modified or reconstructed. In addition, the commenter expects it would also streamline owner/operator compliance programs, which should likewise improve compliance and overall performance.

Response II-3-19: See the discussion in Section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa) in the preamble to the final rule.

## **Chapter 4. Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations**

### **4.1 NSPS OOOOb for Well Sites and Centralized Production Facilities**

#### **4.1.1 General Support**

Comment: Commenters (1611-East Liberty Presbyterian Church, 1620-Evangelical Environmental Network, 1627/1642-Peace, Justice, Sustainability NOW!, 1647-Private Citizen, 1655-American Academy of Pediatrics (AAP), 1658-Physicians for Social Responsibility, 2028-Westmoreland Marcellus Citizens' Group, 2038-Private Citizen, 2039-Citizens to Preserve Ligonier Valley, Inc., 2147-Private Citizen, 2163-EOS at Federated Hermes, 2164-Nordea Asset Management, 2177-Ute Indian Tribe, 2182-Ohio Conservative Energy Forum, 2190-Miller/Howard Investments, Inc., 2191-Boston Trust Walden Company, 2206-Legal & General Investment Management America, Inc (LGIM America), 2209-Public Land Solutions, 2212-Union of Concerned Scientists, 2217-Religious Action Center of Reform Judaism, 2226-Thermo Fisher Scientific, 2244-Private Citizen, 2245-Philip Mecham, 2249-National Association of Clean Air Agencies (NACAA), 2256-Mille Lacs Band of Ojibwe, 2271-Private Citizen, 2285-Bailard, 2313-Mimi Plevin-Foust, 2329-Lone Star Chapter of the Sierra Club, 2341-Harvard's Environmental and Energy Law Program, 2352-Environment Texas Research and Policy Center, 2356-Earthworks et al., 2364-CleanEarth4Kids.org, 2388-ExxonMobil, 2392-Earthjustice et al., 2394-Earthworks, 2396-Shell Oil Company, 2404-Dakota Resource Council (DRC), 2407-Methane Action, 2420-Wisconsin Health Professionals for Climate Action, Inc. (WHPCA), 2428-American Petroleum Institute (API), 2433-Environmental Defense Fund (EDF et al.), 2434-Private Citizen, 2436-Private Citizen, 2455-Private Citizen, 2456-Private Citizen, 2459-BMO Global Asset Management, 2461-Conservatives for Responsible Stewardship, 2466-Private Citizen, 2501-Orion Strategies, 2627-British Columbia Investment Management Corp.) 2628-Nancy Parks, 2796-Chicago Area Peace Action, 2883-US Senator Martin Heinrich et al., 3001-Great Old Broads for Wilderness, 3660-Center for Progressive Reform and Green Latinos, 3083-Transformative Wealth Management, 3335-Placer People of Faith Together--Environmental Interest Group, 3399-Mothers For Nuclear, 3418-Maine Solar Energy Association, 3486-Sharon Furlong, 3507-Save the Sound, 3585-Vote Solar, 3602-Private Citizen, 3621-Private Citizen, 3653-Private Citizen, 3705-Breathe Easy Susquehanna County, 3775-Mothers and Others For Clean Air, 3835-Private Citizen) generally support EPA's proposed fugitive emissions standards for well sites, centralized production facilities, and compressor stations. EPA should seek to reduce fugitive emissions to the greatest extent possible. Methane is a potent greenhouse gas for which its direct regulation is appropriate and necessary in order to bring about necessary methane emission reductions while further supporting the benefits of the increased use of natural gas for expeditiously reducing GHG emissions throughout the U.S. economy and in other countries. Some commenters note maintaining a strong fugitive emissions program will ensure that leaks from oil and gas facilities that disparately impact Black, Latino, tribal, and rural and low-income communities are addressed in a timely manner, resulting in much needed reductions of the dangerous and toxic pollutants emitted by these facilities.

Commenters (2163-EOS at Federated Hermes, 2164-Nordea Asset Management, 2190-Miller/Howard Investments, Inc., 2191-Boston Trust Walden Company, 2206-LGIM America,

2341-Harvard's Environmental and Energy Law Program, 2455-Private Citizen, 3705-Breathe Easy Susquehanna County) believe the rule should maintain strengthened provisions to require leak monitoring at all sites with leak-prone equipment, including high-polluting, smaller wells, while providing flexibility for compliance by allowing a wider selection of advanced technologies to be used if they deliver equal or better reductions. The commenter (2206-LGIM America) notes that research has shown that these wells can often be a significant source of methane emissions and the lack of ongoing monitoring may allow them to continue the outsized rate of pollution. The commenter (2206-LGIM America) adds that ownership data has also shown that such wells are often owned by large companies, who likely have the financial wherewithal to perform more robust maintenance.<sup>1</sup>

Commenter (2177-Ute Indian Tribe) supports the increased fugitive emissions monitoring at all sites and supports the inclusion of storage vessels such as tank batteries. However, given the sheer number of facilities that would be subject to the final rule, the EPA should consider working with the commenter to develop a comprehensive LDAR program which may include delegation of inspection and enforcement activities to the Tribe.

Commenter (2182-Ohio Conservative Energy Forum) indicates that the EPA's proposal improves methane regulation standards by requiring regular monitoring at well sites, including low-producing wells, which allows our methane mitigation industry to deploy technology to reduce emissions and generate revenue to boost our economy. The updated draft rule improves upon the original rule by eliminating the loophole in leak detection and repair standards and will require routine inspections at wells with equipment known to malfunction.

Commenter (2182-Ohio Conservative Energy Forum) finds according to research done by the University of Cincinnati in southeastern Ohio, many wells that produce less than a barrel of oil per day leak into the atmosphere more than 100 percent of their reported gas production. The gas wasted by these low-producing wells could meet the heating and cooking needs of nearly every home in the state of Ohio. The inclusion of routine monitoring at these low producing well sites is an important step forward in these proposed rules that will help us take advantage of capturing and eliminating methane waste. Solutions exist today for producers to eliminate roughly half of their methane emissions with existing technology at no net cost. Bringing this added gas to market increases tax revenues to communities from Ohio's severance tax, alongside corporate and payroll taxes and royalty revenues to leaseholders across the state.

Commenter (2215-West Virginia Rivers Coalition et al.) argues cutting methane emissions within the oil and gas sector is the quickest and most impactful way to limit global warming. In the United States, oil and gas systems are among the largest sources of methane emissions at 32 percent according to EPA's Greenhouse Gas Inventory. Yet research has repeatedly shown that the true extent of oil and gas methane emissions are likely much higher than this; for instance, a study funded by the Environmental Defense Fund found that oil-and-gas-sector methane emissions are 60 percent higher than EPA's estimates show. As the second most abundant greenhouse gas, methane is responsible for approximately 20 percent of global emissions and

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<sup>1</sup> Environmental Defense Fund - By the numbers: Marginal oil and gas wells;  
[https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021\\_0.pdf](https://www.edf.org/sites/default/files/documents/MarginalWellFactsheet2021_0.pdf).



estimated to cause between a quarter and a half of the warming our planet has experienced to date.

Commenter (2256-Mille Lacs Band of Ojibwe) applauds the EPA's efforts in creating a more comprehensive approach to reducing methane and VOC pollution. Methane is a powerful greenhouse gas with a 100-year global warming potential 28-34 times that of carbon dioxide, while other types of petroleum-based VOCs seriously pose both health and safety risks. We have natural gas transmissions piping paralleling major travel-ways, passing through our treaty-ceded territories, connecting communities along the way. They generally are low in emissions except for where the transmission piping is interrupted by a compressor station or to other types of gas-handling equipment. By reducing or eliminating the methane and other natural gas-associated VOCs at these connection points, this action will help the United States to meet its climate change mitigation goals.

Commenter (2455-Private Citizen) suggests the EPA leverage the additional reporting occurring in this program and create annually updated, gridded estimates of methane emissions across the US. These data products will be critical for improving methane emission science.

Commenters (2456-Hal Schmid, 3335-Placer People of Faith Together--Environmental Interest Group, 3486-Sharon Furlong, 3507-Save the Sound) agree, methane poses a grave danger to the planet. It exerts more than 80 times the impact of carbon dioxide, pound for pound, making it a major driver of global warming and climate change and the immediate low-hanging fruit in the effort to address health and climate change issues related to the gas and oil industry and our petroleum consumption. Commenter (2883-US Senator Martin Heinrich et al.) states methane is responsible for around 30% of the global warming we are experiencing today.<sup>2</sup>

Commenter (2364-CleanEarth4Kids.org) stresses the administration must take immediate action to cut methane pollution from oil and gas operations and development to 90% below 2005 levels by 2030.

Commenter (2392-Earthjustice et al.) notes that maintaining a strong LDAR program will ensure that leaks from oil and gas facilities that disparately impact Black, Latino, tribal, and rural and low-income communities are addressed in a timely manner, resulting in much needed reductions of the dangerous and toxic pollutants emitted by these facilities.

Commenter (2396-Shell Oil Company) has worked with EPA to help craft an efficient and effective regulatory framework for reducing methane emissions through leak detection and repair programs, enhanced pneumatic device standards, control requirements on regulated storage tanks, and reduced emissions completions on new and modified wells. Their support for methane regulation extends to EPA's Proposal to update, strengthen, and expand the current Subpart OOOOa NSPS standards for limiting methane and VOC emissions from new, modified, and reconstructed onshore facilities. These changes, as a general matter, will enhance and improve upon the existing regulations to limit emissions from the oil and gas sector.

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<sup>2</sup> [https://urldefense.com/v3/\\_\\_https://www.iea.org/reports/global-methane-tracker-2022/methane-and-climate-change\\_\\_;!!Bg5easoyC-OII2vIEqY8mTBrtW-N4OJKAQ!YZMxPbtH7YrrnIJn0OQHgcZ8uus0caYMaK5JnAz-19qAX0u\\_DpXPTR06rEPwNPwoC2CM59-DPmk\\$](https://urldefense.com/v3/__https://www.iea.org/reports/global-methane-tracker-2022/methane-and-climate-change__;!!Bg5easoyC-OII2vIEqY8mTBrtW-N4OJKAQ!YZMxPbtH7YrrnIJn0OQHgcZ8uus0caYMaK5JnAz-19qAX0u_DpXPTR06rEPwNPwoC2CM59-DPmk$).

Commenter (2396-Shell Oil Company) adds their support for direct methane regulation extends to existing onshore oil and natural gas sources. The commenter has gone on record on many occasions supporting the adoption of effective and flexible federal regulations for limiting methane from existing onshore sources. The commenter believes that the EPA's strong commitment to develop such regulations in this area makes the Agency uniquely qualified for developing a workable regulatory framework for reducing methane emissions from existing onshore facilities within oil and natural gas sector in an efficient and effective manner.

Commenter (2433-EDF et al.) states fugitive emissions from leaks and equipment failures are the most significant source of methane emissions from the oil and gas sector, representing over two thirds of total emissions in the production segment.<sup>3</sup> Readily available and low-cost technologies exist to find and fix these leaks and malfunctions. Comprehensive LDAR standards are therefore an indispensable element of any program aiming to drive down methane emissions from oil and gas. EPA should seek to reduce fugitive emissions to the greatest extent possible, with the ultimate goal of fully eliminating these preventable and unnecessary emissions.

Commenter (2433-EDF et al.) argues final rules should ensure fugitive emissions reductions of at least 80%, or roughly equivalent to EPA estimates of what quarterly OGI would achieve. The commenter estimates that a comprehensive and frequent monitoring and repair regime could reduce methane emissions by over 1.5 million tons per year (tpy) and urge EPA to finalize standards at least as protective as what it has proposed.

Commenter (2466-Private Citizen) notes the oil and gas industry is one of the leading sources of methane pollution in the U.S., emitting roughly 16 million metric tons of methane every year. The commenter states low producing wells account for just 6% of production nationwide but are responsible for 50% of methane emissions at oil and gas well sites. According to data provided by Clean Air Council, in our region of the United States, these wells emit 1.2 million tons of methane annually. Methane is responsible for approximately one third of the warming from greenhouse gasses occurring today.

Response II-4-1: EPA acknowledges the commenters' support. The EPA is finalizing several requirements to strengthen requirements for fugitive emissions from well sites, centralized production facilities, and compressor stations.

#### ***4.1.2 Affected Facility/Definitions***

##### ***4.1.2.1 Modification to Centralized Production Facility***

Comment: Commenters (2177-Ute Indian Tribe, 2428-API, 2179-Kansas Independent Oil and Gas Association (KIOGA), 2304-Pennsylvania Independent Oil & Gas Association (PIOGA)) express concerns regarding the proposed definition of modification of fugitive emissions components at a centralized production facility.

Commenter (2177-Ute Indian Tribe) states the following requirement in §60.5365b(i)(2)(ii) is not feasible as wells sending production to a centralized facility may be owned by a different

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<sup>3</sup> 2022 Joint Environmental Comments, *supra* note 1, at 65. [99] 87 Fed. Reg. at 63177.

entity and the owner/operator of the centralized facility is likely not aware of changes occurring at connected wells:

“A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or”

Commenter (2177-Ute Indian Tribe) recommends that: Changes in gas composition or volume received at a centralized production facility cause a significant increase in potential emissions. A significant increase in emissions is an increase that causes a change in applicability to existing regulations, or increases emissions of any regulated pollutant by more than 2 tpy or any single HAP by more than 0.5 tpy.

Commenter (2177-Ute Indian Tribe) recommends removing the requirement in §60.5365b(i)(2)(iii) that reads:

“A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.”

The commenter states the same rationale as provided above, that the centralized production facility may be owned by a different entity.

Commenter (2428-API) indicates that the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. To address this concern, the commenter suggests that the modification criteria for centralized production facilities be limited to “An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.” This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. The commenter offers the following revisions to §60.5365b(i)(2):

For purposes of §60.5397b and §60.5398b, a “modification” to centralized production facility occurs when: an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.

~~(4) (Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;~~

~~(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or~~

~~(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.~~

Commenters (2179-KIOGA, 2304-PIOGA) note that EPA has abandoned the traditional definition of “modification” that typically requires an increase in emissions associated with a “modification” to trigger NSPS. A not-so-hypothetical hypothetical for owners/operators of low production wells/facilities is where there may be a few small oil wells that periodically vent as part of the normal production process. Those emissions could be controlled by tying the venting of those wells into a central production facility and ultimately reducing emissions, but the proposed rule would deem such changes a “modification” even though that control method results in emission reductions. EPA’s proposed definition of “modification”, without linking it to an increase in emissions, creates a huge disincentive for operators of low production wells to make changes that benefit the environment and their small business’s bottom lines. For example, older conventional, or “legacy”, oil and gas wells often produce far less gas than the capacity of the smallest available reciprocating compressor, which is about 3 horsepower (hp). Having one small compressor to draw from multiple wells is more practical, produces lower emissions, uses less energy, and is easier to maintain and more economical, but the proposed rule would discourage/punish such changes. A very small centralized compressor should be treated the same as a single well wellhead compressor because it has far less emissions, uses much less energy, and reduces pressure over the whole system, lowering the chance of leaks. A centralized compressor of 20 hp or less, or handling 100,000 cubic feet per day (or 100 mcf/d) should be treated as a single well compressor.

Commenter (2179-KIOGA) adds some operators in Kansas may drill 200 oil wells and perform work that would meet EPA’s definition of a “modification” for more than 250 existing wells in a five-year period. This is an average of 90 wells being drilled or modified each year, not including associated tanks or other fugitive emissions components. The commenter expects this level of activity to resume as oil price increase for some of the active owners/operators in Kansas. They believe that smaller owners/operators will reduce their drilling and maintenance programs until the oil price increases again. The reporting work will continue to grow each year as they continue to drill and modify wells because the current year work is added to all work from prior years. This growing work load will require the hiring of additional employees in the future.

Response II-4-2: Regarding the comments that a centralized production facility may be owned by a different company than the well sites, this is not EPA’s understanding of these sites. As discussed in the November 2021 Proposal, the centralized production facility definition was created, in part, to address the scope of fugitive emissions standards at well sites. The EPA described that these facilities are a type of well site; therefore, it is not the EPA’s understanding for them to have a different owner. If the liquids have undergone custody transfer, then the operations described are no longer in the producing operations and would be a natural gas processing plant or a compressor station, depending on the scope of operations present at the site. The commenter did not provide rationale why this understanding is not correct. See also the response in Chapter 13 Storage Vessels at II-13-40.

Regarding the comment that only “significant” changes in emissions should trigger modification, the EPA notes that modification is defined as “any increase” not a “significant” increase.

Regarding the comment that the definition of “modification” does not address the situation where a control method may result in an emissions reduction, such as when a owners/operators of low production wells/facilities may control small oil well venting by tying the venting of those wells into a central production facility, the EPA notes that both NSPS OOOOb and EG OOOOc

require a reduction in emissions, primarily through recovery of the gas. If the associated gas is sent to a centralized production facility for recovery and meets the requirements of 40 CFR §60.5377b(a), then the provisions of 40 CFR §60.14(e)(5) would apply, and this would not be a modification.

Regarding the commenter who notes the addition of employees, the EPA did not see that the commenter provided a specific comment request for the EPA to consider.

#### 4.1.2.2 Definition of Well Site

Comment: Commenter (2433-EDF et al.) cites to EPA’s proposed definition of a well site:

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For the purposes of the fugitive emissions standards at §60.5397b, a well site does not include:

- (1) UIC Class II oilfield disposal wells and disposal facilities;
- (2) UIC Class I oilfield disposal wells; and
- (3) The flange immediately upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.”

Commenter (2433-EDF et al.) recommends that EPA make clear that a well site includes all the equipment at the site to ensure that all fugitive emissions components associated with equipment at the site are subject to the monitoring and repair standards.

Response II-4-3: The EPA has not revised the definition of a well site in response to this comment (see Response II-4-15 for an explanation of the definition revision). The EPA believes the final definition of “fugitive emissions component” clearly includes any component and that no additional clarification is needed per the commenter’s suggestion.

*Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411b, thief hatches or other openings on a storage vessel not subject to §60.5395b, compressors, instruments, meters, and yard piping.

In addition, §60.5397b(a) of the final rule clearly states all fugitive emissions components affected facilities must be monitored.

Part 3 of the definition of a well site cited by the commenter helps clarify the boundary of the well site at the point of custody transfer.

The EPA has also clarified in the final regulatory text which monitoring requirements apply to single wellhead only well sites, small well sites, multi-wellhead only well sites, and well sites and centralized production facilities with major production and processing equipment.

#### 4.1.2.3 Fugitive Emissions

Comment: Commenter (2000-Step2Compliance) suggests that the following definition of fugitive emissions:

“Fugitive emissions are defined as any indication of visible emissions from a fugitive emissions component that are not part of normal operations and intermittent in nature observed using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.”

Commenters (2363-Continuous Emission Monitoring Coalition (CEMC), 2433-EDF et al, 2448-Project Canary, PBC) believe the definition of fugitive emissions should be updated to account for emissions detected using alternative technologies to screen and/or monitor for fugitive emissions leaks. This definition appears to be identical to what is referenced in NSPS OOOOa, §60.5397a(a)(1). The definition is limited to OGI and Method 21. Commenter (2433-EDF et al) suggests amending the definition or otherwise clarifying in section 60.5398b that any emissions detected using the procedures described in section 60.5398b are considered fugitive emissions if the source is a fugitive emissions component.

Commenters (2363-CEMC, 2448-Project Canary, PBC) propose the following definition:

“Fugitive emissions are defined as any indication of visible emissions observed from a fugitive emissions component using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part, or any emissions detected from a fugitive emissions component using an alternative screening technology as described in Tables 1 and 2 of this Subpart, or reaching a facility-appropriate action-level as defined in 60.5398bI(4)(i) using an approved continuous emissions monitoring system.”

Response II-4-4: In the December 2022 Supplemental Proposal, the EPA proposed to define fugitive emissions as:

*Fugitive emissions* are defined as any indication of visible emissions observed from a fugitive emissions component using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.

To reflect that the EPA has determined that inspections using AVO is also an appropriate method for identifying fugitive emissions, AVO has been added to the definition of fugitive emissions in the final rule in addition to OGI and Method 21.

The EPA is finalizing the following definition for fugitive emissions:

*Fugitive emissions* means, for the purposes of §60.5397b, any indication of emissions observed from a fugitive emissions component using AVO, an indication of visible emissions observed from an OGI instrument, or an instrument reading of 500 ppmv or greater using Method 21 of appendix A-7 to this part.

#### 4.1.2.4 Fugitive Emissions Component

Comment: Several Commenters (1583-Oklahoma Department of Environmental Quality (ODEQ), 2000-Step2Compliance, 2221-Texas Pipeline Association, 2326-American Exploration & Production Council (AXPC), 2337-Kansas Department of Health and Environment (KDHE), 2393-Oklahoma Office of the Secretary of Energy and Environment, 2428-API, 2433-EDF et al.) request various clarifications and revisions to the definition of fugitive emissions component.

Commenter (2000-Step2Compliance) states the definition of a fugitive emissions component<sup>4</sup> in OOOOa includes verbiage about devices that vent as part of normal operation. The definition of fugitive emissions component<sup>5</sup> in OOOOb and OOOOc was significantly reduced from the definition of fugitive emissions component in OOOOa, excluding the verbiage about venting due to normal operations, and there was a new definition added of fugitive emissions<sup>6</sup> which defines any visible emission detected with an OGI camera as a leak.

Commenter (2000-Step2Compliance) states with the original proposal that would have covered all facility types under the Appendix K protocol, there would have been the additional and clarifying definition Persistent Leak that is in the Appendix K definitions<sup>7</sup> to account for venting due to normal operations. The commenter states now that Appendix K only applies to natural gas processing plants, that leaves other facility types (well sites, centralized production facilities, and compressor stations) that are utilizing OGI for leak detection without the additional persistent leak definition that makes it appear that venting due to normal operations falls under the definition of fugitive emissions.

Commenters (2000-Step2Compliance, 2221-Texas Pipeline Association, 2283-Endeavor Energy Resources, 2399-GPA Midstream Association, 2433-EDF et al, 2363-Continuous Emission Monitoring Coalition (CEMC), 2448-Project Canary, PBC) state that the rule lacks a clear definition as to what is a fugitive emissions component and some offer alternatives for a definition and what it should include.

Commenters (2221-Texas Pipeline Association, 2283-Endeavor Energy Resources, 2399-GPA) ask that EPA not adopt a revised definition of “fugitive emissions component,” in proposed §60.5430b and §60.5430c, as the revisions could present substantial confusion and potentially unduly broaden the scope of fugitive emissions to include emissions from equipment designed as part of the process to vent emissions. The commenters urge EPA not to make this revision.

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<sup>4</sup> Under OOOOa, Fugitive Emissions Component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411 or § 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395 or § 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

<sup>5</sup> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411b, thief hatches or other openings on a storage vessel not subject to §60.5395b, compressors, instruments, meters, and in yard piping.

<sup>6</sup> Fugitive emissions are defined as any indication of visible emissions observed from a fugitive emissions component using optical gas imaging or an instrument reading of 500 parts per million (ppm) or greater using Method 21 of appendix A-7 to this part.

<sup>7</sup> Persistent leak is any leak that is not intermittent in nature.

Commenter (2283-Endeavor Energy Resources) finds EPA's definition of fugitive emissions sources is unnecessarily broad and vague. The requirements should be clear and straightforward so that operators do not inadvertently miss inspections.

Commenters (2221-Texas Pipeline Association, 2326-AXPC) believe EPA should limit the list of fugitive emission components to equipment that is not designed to vent as part of its intended operations, so as to keep the rules' focus on equipment that creates emissions as the result of an abnormal, unintended condition that needs to be repaired. The definition should not include equipment such as thief hatches and crankcase vents, which are intended to release emissions as part of normal operations; as such, revising the definition to clearly exclude such equipment would bring the definition more in line with the traditional concept of what constitutes a fugitive emissions component, *i.e.*, a piece of equipment that is emitting fugitive emissions due to unintended malfunction, not intended operations. Commenter (2326-AXPC) adds uncontrolled storage vessels are designed and intended to emit to atmosphere and may do so through thief hatches or other openings. It is illogical for the observance of allowable and intended emissions from this equipment to trigger repair requirements.

Commenter (2221-Texas Pipeline Association) believes narrowing the list in this manner would also have the benefit of reducing the number of individual components that would be subject to the extensive survey, repair, replacement, and recordkeeping/reporting requirements that would apply to components covered by the fugitive emissions rules. The application of such onerous requirements should be as limited as possible, and in no event should such requirements be applied to equipment that is allowing emissions as an integral part of its design and operations. EPA has not seen fit to include an unrealistically expansive list of fugitive emissions components in other NSPS subparts; the leak detection and repair regulations in Subpart VVa, for example, list only the following covered equipment: "pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart."<sup>8</sup>

Commenters (2326-AXPC, 2428-API) propose that EPA exclude buried in yard piping from the definition of fugitive emissions component. Buried in yard piping will remain difficult to monitor – in fact, impossible to monitor – so long as it remains buried. As proposed, difficult and unsafe-to-monitor equipment designations are available only where the operator monitors using Method 21, and for difficult-to-monitor equipment, an operator must monitor at least once per calendar year. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.<sup>16</sup> Commenter (2326-AXPC) expects most operators to utilize OGI cameras, which have no difficult or unsafe-to-monitor equipment designation. Operators cannot ever monitor buried components and thus cannot comply with the requirement to monitor buried in yard piping, even on an annual basis if designated as difficult-to-monitor.

Commenter (2337-KDHE) believe AVO surveys on yard piping sound reasonable, but it is not reasonable to demand sensors be run up and down and around pipes as for Method 21 monitoring. Piping inspection should be limited to AVO, exempting Method 21 (when used in place of OGI) from inspection of plant piping.

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<sup>8</sup> 40 CFR § 60.481a.



Commenter (2428-API) argues monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.

Commenter (2428-API) states definitions should also include the appropriate references to NSPS OOOO and OOOOa. As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring.

Commenter (2428-API) recommends the following revisions, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411, §60.5411a, or §60.5411b, thief hatches or other openings on a controlled storage vessel not subject to §60.5395, §60.5395a, or §60.5395b, compressors, instruments, and meters, ~~and in yard piping~~. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Commenters (2393-Oklahoma Office of the Secretary of Energy and Environment, 2433-EDF et al.) and 1583-Oklahoma Department of Environmental Quality (ODEQ) commented that the definition for “fugitive emissions component” needs clarification regarding whether emissions from control devices should be included.<sup>9</sup> The December 2022 Supplemental Proposal preamble states, “EPA agrees that control devices should not be treated as fugitive emissions components and is therefore revising the definition in this proposal to not include those devices.” The commenters support this revision.

Commenter (2433-EDF et al.) recommends including tank batteries and other site types in the definition to avoid potential ambiguity about where fugitive monitoring is required. Including a specific reference or a cross-reference to the affected facility definition is important to avoid

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<sup>9</sup> See “State of Oklahoma’s Comments on EPA’s Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review” Document ID EPA-HQ-OAR-2021-0317-0727.

ambiguity and ensure fugitive monitoring occurs at tank batteries and centralized production facilities, which are known large sources of fugitive emissions. Finally, the commenter recommends that EPA include a non-exhaustive but more comprehensive list of fugitive emission components and equipment to help ensure they are not overlooked during fugitive monitoring and to reduce the potential for interpretations that might incorrectly narrow the scope of fugitive monitoring.<sup>10</sup>

Commenter (2433-EDF et al.) supports the inclusion of yard piping, and again urge EPA to clarify that the list of components is non-exhaustive. The commenter recommends that EPA revise the language to ensure fugitive emissions components include all components on all types of equipment located anywhere at a well site, centralized production facility, tank battery, or compressor station.

Commenter (2433-EDF et al) believes EPA is not defining control devices as fugitive emissions components and has proposed separate monitoring requirements to ensure control devices operate as intended, including monthly Method 22 inspections. The commenter agrees with this approach, but urge EPA to also require that flares and control devices be monitored for compliance assurance during all fugitive emissions surveys, both under the OGI and AVO program and under the alternative periodic screening options. Control devices and flares are among the most commonly-observed sources of methane emissions, including super-emitter events.<sup>11</sup> It is therefore critical that they are regularly inspected and monitored to ensure proper operation. Monitoring flares and control devices during fugitive emission surveys poses very little additional burden and can ensure emission events are avoided. Large methane slip, unlit flares, and other types of malfunctions are all violations of EPA's proposed and existing requirements for the operation of control devices.<sup>12</sup> We therefore support regular monitoring for compliance assurance purposes both through EPA's proposed requirements and during fugitive emissions surveys.

Commenter (2433-EDF et al.) urges EPA to make clear that fugitive monitoring would be required at any source receiving a variance under EG OOOOc or otherwise not subject to the standards applicable to pneumatics, control devices, covers and closed vent systems, and tanks. If given a variance, those sources would not be required to monitor for compliance assurance and any leaks would therefore properly be characterized as fugitive emissions and must be monitored during fugitive emissions surveys. The commenter urges the agency to ensure that entire sites are comprehensively monitored (whether as part of LDAR or for compliance assurance) during every survey and believe that emissions from equipment in violation of underlying standards are properly characterized as violations rather than fugitives.

Commenter (2433-EDF et al) analyzed the most commonly reported leaking components.<sup>13</sup> The commenter found that the dataset contained 56,836 reported component leaks from 174 unique component types and 20 types of equipment. Table 6 within the commenter's attachment displays the most commonly reported component leaks in upstream fugitive emissions surveys

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<sup>10</sup> See *id.*

<sup>11</sup> See, e.g., Genevieve Plant et al., Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane, 377 Sci. 6614 (2022), <https://www.science.org/doi/10.1126/science.abq0385>.

<sup>12</sup> See Proposed 40 C.F.R. § 60.5412b(a)-(c).

<sup>13</sup> For a full description of the methodology, see Env't Def. Fund, OOOOa Compliance Report Analysis Methodology, *supra* note 116.

using OGI. This information confirms the importance of monitoring at failure-prone equipment types that contain the most commonly leaking fugitive emissions component types.

Commenters (2393-Oklahoma Office of the Secretary of Energy and Environment, 2433-EDF et al) and 1583-ODEQ) state EPA is defining fugitive emissions components to include all thief hatches and other openings on storage vessels that are not also subject to control as storage vessel affected facilities. Commenters support this structure as long as all storage vessels and controls on storage vessels are regularly monitored. EPA's newly proposed compliance monitoring requirements ensure this, and the commenters believe this structure is appropriate given the underlying tank control standards.

Commenter (2399-GPA) argues EPA provided no rationale for altering the longstanding definition and did not either acknowledge the revision or the change in interpretation that appears to significantly expand the types of equipment considered to be "fugitive emissions components."<sup>14</sup> Any final rule should restore the previous definition of "fugitive emissions components."

Commenter (2399-GPA Midstream Association) request that EPA restore the word "Controlled" in the definition of "Fugitive Emissions Component," which the commenter states EPA deleted without any explanation. The definition in §60.5430a currently includes "thief hatches or other openings on a controlled storage vessel not subject to §60.5395 or §60.5395a." Fugitive emissions from thief hatches or openings on uncontrolled tanks are expected as the tank breathes in and out through these vents to prevent the tank from rupturing. EPA should acknowledge that the vents on uncontrolled tanks are expected to vent and should not be considered fugitive emissions.

The commenter (2399-GPA Midstream Association) recognizes that even uncontrolled, atmospheric tanks are operated under a slight amount of pressure, often at approximately one ounce. The commenter ran a generic process simulation in ProMax comparing uncontrolled tanks with one ounce of pressure and uncontrolled tanks with zero pressure. Assuming all other inputs are the same, the total tank emissions were nearly identical with only a two percent difference (2.53 tpy vs. 2.58 tpy).

Commenter (2399-GPA Midstream Association) continues, the TSD's discussion of model production facility plants further supports the commenter's position. That discussion states that "Model Plant 3 contains tanks, but as they are uncontrolled, the emissions from these tanks are allowed to vent to the atmosphere. Controlled tanks in Model Plant 4 must be vented through a closed system to a control device. Here, an open thief hatch or leak in the closed vent system could require action to repair the leak."<sup>15</sup> The TSD's Table 1 showed zero tanks for Model Plant 3 because there are zero controlled tanks.<sup>21</sup>

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<sup>14</sup> Despite changing the definition of "fugitive emission components" to include thief hatches and other openings, EPA's Technical Support Document does not account for them. It expressly states that the "analyses for fugitive emissions from compressor stations included in the November 2021 proposed TSD has not changed." EPA, Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emission Guidelines (EG), EPA-HQ-OAR-2021-0317-1578 (Oct. 2022) ("TSD") at 5-1.

<sup>15</sup> Coburn-Strott Memo at 14.

Commenter (2399-GPA Midstream Association) states this indicates that EPA failed to realize the importance of the definitional change, the proposal has made the change without providing any explanation. Conversely, if EPA intended to require leak detection monitoring for components that are no longer part of a closed vent system, then the agency must explain the rationale for this regulation and define the benefit EPA claims this could possibly yield. Otherwise, the commenter requests that EPA expressly state that it will apply the definition of “fugitive emission component” currently found in §60.5430a to NSPS OOOOb and EG OOOOc.

Response II-4-5: As summarized above, the EPA received a number of comments requested various revisions to the definition of fugitive emissions component. The final rule retains the definition of fugitive emissions components mostly as proposed and reads as follows:

*Fugitive emissions component* means any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, such as valves (including separator dump valves), connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411b, thief hatches or other openings on a storage vessel not subject to §60.5395b, compressors, instruments, meters, and yard piping.

The EPA disagrees with comments asserting that the EPA did not explain the reason for the change in the definition of a fugitive emissions component. The December 2022 Supplemental Proposal explained why EPA found it appropriate to propose certain revisions to the definition that was proposed in November 2021.<sup>16</sup> This included EPA acknowledging that it was correcting an error made in the November 2021 proposal, which inadvertently included storage vessels that would already be subject to control as storage vessel affected facilities/designated facilities, including regular inspections of thief hatches and other sources of fugitive emissions that are separately required as part of the proposed standards for storage vessel affected facilities/designated facilities. As reflected in the final definition of fugitive emissions components shown above, the EPA is defining fugitive emissions components to include all thief hatches and other openings on storage vessels that are not subject to control as storage vessel affected facilities. The EPA does not believe it is appropriate to specify “controlled storage vessel” because thief hatches and other openings (except vents) on uncontrolled tanks are not expected to allow emissions during normal and proper operation and thus the openings should be monitored for fugitive emissions. As discussed in the December 2022 Supplemental Proposal, EPA maintains that control devices should not be treated as fugitive emissions components. The EPA anticipates that control devices will be used to meet at least one of the emissions standards in the final rules, and as such, they would be subject to the control device requirements in NSPS OOOOb or EG OOOOc. The EPA believes these revisions provide clarity and eliminate overlapping and redundant requirements.

In the final NSPS OOOOb and EG OOOOc rules, the EPA has retained yard piping<sup>17</sup> in the definition of fugitive emissions components. A definition of yard piping was added for clarity.

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<sup>16</sup> 87 FR 74723-74724.

<sup>17</sup> The EPA recognizes that the terms “yard piping” and “in yard piping” were used interchangeably in the December 2022 Supplemental Proposal. The final rule uses the term “yard piping” consistently.

As discussed in the December 2022 Supplemental Proposal, pipes can experience cracks or holes, which can lead to fugitive emissions. The inclusion of yard piping in the definition of fugitive emissions components will help ensure that fugitive emissions from these sources do not go undetected during fugitive emissions monitoring and that issues found from the pipe itself leading to the fugitive emissions are addressed. If industry is already conducting checks for leaks as standard practice and code, this would further assist in ensuring that fugitive emissions are minimized. AVO and OGI can be used to detect fugitive emissions from cracks and other defects in yard piping by scanning along the length of the piping. However, the EPA acknowledges that EPA Method 21 does not include instructions for monitoring yard piping; therefore, the EPA is providing directions in this final rule on how to monitor yard piping while conducting an EPA Method 21 monitoring survey in NSPS OOOOb and EG OOOOc.

The EPA recognizes the difficulty of monitoring yard piping that is buried, as it may require disturbing the surface, which could inadvertently cause emissions; therefore, the final NSPS OOOOb and EG OOOOc rules only require monitoring of yard piping and associated fugitive components (*e.g.*, connectors) that are “at or above ground level.”

Regarding a commenter’s request that the definition of fugitive emissions components explicitly includes separators, the EPA agrees that, although the list of components in the definition is not exhaustive, it is worthwhile to eliminate any ambiguity that separator dump valves are fugitive emissions components. The EPA is finalizing a definition of fugitive emissions components in NSPS OOOOb and EG OOOOc that specifically includes separator dump valves, thus clarifying that the separator dump valve is subject to monitoring by OGI, AVO, or other detection methods. In addition, because malfunctioning separator dump valves are a known source of large emissions (as the commenter noted) and because sometimes there is visual evidence of the malfunction, the EPA is requiring in the final rule that, during the regular AVO monitoring surveys (either quarterly or bimonthly depending on the site), a visual inspection must be conducted of all separator dump valves to ensure that they are free of debris and not stuck in an open position, and any dump valve not operating as designed must be repaired.

The EPA believes that the fugitive emissions components definition and the fugitive emissions components affected facility definition both clearly include centralized production facilities, which include tank batteries in the production segment.

See the final rule preamble section XI.H.2 for the response to the request for monitoring of flares for compliance assurance.

Comment: Commenter (2286-Colorado Department of Public Health and Environment (CDPHE)) requests that EPA define “yard piping” as used in the supplemental proposal and proposed regulatory language.<sup>18</sup> Under Colorado’s LDAR program and Storage Tank Emission Management (STEM) requirements pursuant to Colorado’s Regulation Number 7, the Division has included various piping in control configurations and as components subject to the LDAR program or as a piece of a closed vent system subject to monitoring. The commenter requests

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<sup>18</sup> See 87 FR 74702 at 74723, EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component ... to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly.

that EPA define yard piping to ensure clarity in application of both the federal and Colorado's programs.

Response II-4-6: The EPA agrees with the commenter that a definition of yard piping should be included in the regulatory language. The final rule defines yard piping as follows:

*Yard piping* means hard-piping at a well site, centralized production facility, or compressor station that is not part of a closed vent system.

Comment: Commenter (2197-Roy Massengale) notes the current proposed definition of fugitive emissions component would include rod packing vents already regulated under §60.5385b (*i.e.*, duplicative regulation). The commenter recommends including a sentence in the definition of fugitive emissions component such as:

“Rod Packing vents regulated under §60.5385b would not be considered a Fugitive emissions component.”

Response II-4-7: The fugitive emissions requirements in §60.5397b of the final rule do not apply to rod packing for reciprocating compressors because this is a regulated source under the rule. The EPA believes the rule make this clear, and EPA does not find it necessary to revise the definition of fugitive emissions components for this purpose.

#### 4.1.2.5 Open-Ended Valve/Line

Comment: Commenter (2433-EDF et al.) cites the definition of open-ended valve or line or open-ended vent line:

*“Open-ended valve or line or open-ended vent line* means any valves, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.”

Commenter (2433-EDF et al.) states EPA should eliminate the exception for safety relief valves. Safety relief valves can malfunction and cause unintended and fugitive emissions, and should therefore be considered a fugitive emissions component.

Response II-4-8: The EPA disagrees with the suggestion to remove the exception for safety relief valves. The definition of open-ended valve or line or open-ended vent line is consistent with the definition of this term in 40 CFR part 60, subparts VV and VVa and has been retained in this final rule.

#### 4.1.2.6 Wellhead Only Well Site

Comment: Commenter (2179-KIOGA) states the EPA needs to include a definition for wellhead only well sites and low production wells in the yet to be proposed regulatory text.

Response II-4-9: The final rule includes the following definitions for wellhead only well sites:

*Single wellhead only well site* means a wellhead only well site that contains only one wellhead and no major production and processing equipment.

*Multi-wellhead only well site* means a well site that contains two or more wellheads and no major production and processing equipment.

Comment: Commenter (2428-API) notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the DOE study is unavailable.

Response II-4-10: EPA acknowledges the commenter's observation. Following the December 2022 Supplemental Proposal, the EPA received the underlying dataset for the DOE Study, which was previously not available. The EPA further evaluated the methane emissions data obtained during the field campaigns of the DOE Study, as discussed in section XI.A.1.d of the preamble to the final rule.

#### 4.1.2.7 Small/Marginal Well Sites

Comment: Several commenters (2177-Ute Indian Tribe, 2348-Energy Workforce and Technology Council, 2436-Louis Pochet, 2439-State of Michigan Department of Environment, Great Lakes and Energy, 2446-IPAA, 2462-Cynthia Walter) express concern over how EPA has defined and classified a small well site in the proposed rule.

Commenter (2177-Ute Indian Tribe) recommends that EPA revise the definition of "small well site" removing references to natural gas-driven pneumatic controllers, or specifying high-bleed natural gas-driven pneumatic controllers.

Commenter (2177-Ute Indian Tribe) recommends an exemption for wells producing less than 60 MCF/day or 10 BOE/day, as defined by the IOGCC (Interstate Oil & Gas Compact Commission). Wells of these size generally have fewer vented emissions and there is therefore a diminishing rate of return in requiring emission controls for these small sources.

Commenter (2436-Louis Pochet, 2462-Cynthia Walter) provide the following comments on the definition of small well site:

1. The criteria to require monitoring might have been made based on the "potential to emit," but that potential is very hard to predict. Small, new, or old wells that did not produce much gas or oil still have the potential to emit substantial, unintended pollution.
2. Many processes can alter geologic conditions around a well and allow releases of emissions.
3. The large number of abandoned wells, *e.g.*, 200,000 for Pennsylvania alone, and unknown location for most abandoned wells means that more than one well may intersect with a well that was intended to be "small."
4. Research on water contamination from intersecting wells indicates the changing nature of geology and emission potentials from wells. For example, "well" water became contaminated, and chemistry of the water differed substantially among neighbors only 300 feet apart and across days because nearby fracking altered underground geology and the movement of contaminants among aquifers.

Commenter (2348-Energy Workforce and Technology Council) suggests that a small well site be defined as “two or less wells on pad with no other production equipment.” Pad size is an incomplete or insufficient metric on which to base monitoring. Instead, the amount of production should also be factored in, as well as other considerations such as whether artificial lift or other operations with high emission potentiality operate onsite.

Commenter (2439-State of Michigan Department of Environment, Great Lakes and Energy) notes the EPA is defining small well sites as any site with a single wellhead and no more than one piece of certain major production and processing equipment, and associated meters and yard piping. The commenter notes it is unusual for there to be only a single wellhead and one piece of equipment on a wellsite. Typical well sites for small operators and marginal wells are a single wellhead, separator, or heater-treater, and two tanks. Changing the definition of a small well site to include a single wellhead and two to three pieces of equipment would be appropriate.

Commenter (2446-IPAA) indicates that the definition of a small well site appears to overly constrain the scope of sites that should fall into it. For example, EPA estimates that 95,000 sites will fall within its small well site definition. 83 percent of low production wells produce 6 boe/day or less. In total, there are over 600,000 wells in this category (over 330,000 are less than one boe/day and 200,000 are between 1 and 4 boe/day). While many will be single well or multiple well sites, it is highly likely that a sizable number of these wells will fall into EPA's large well definition. Because the large well matrix category captures everything above a threshold of not being a single well site, a multiple well site and a small well site, EPA needs to ensure that its threshold is appropriate. EPA notes in the preamble that the larger end of the DOE Study found wells that were emitting 3 to 4 tpy. In its FEAST model analysis EPA uses an emissions threshold of 8.51 tpy. This emissions rate translates into a well producing about 290 mcf/d and is within EPA's concept of a large facility. However, a facility emitting 3 to 4 tpy will essentially be at the top end of the low production well definition and its emissions will likely be consistent with EPA's small well site matrix category.

Response II-4-11: The EPA is finalizing the definition of a small well site as follows:

*Small well site* means, for purposes of the fugitive emissions standards in §§60.5397b and 60.5398b, a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. Small well sites cannot include any controlled storage vessels (or controlled tank batteries), control devices, natural gas-driven process controllers, or natural gas-driven pumps.

#### 4.1.2.8 Major Production and Processing Equipment

Comment: Commenter (2433-EDF et al) states for the definition of major production and processing equipment, EPA should eliminate the last clause of the definition (“for the purpose of determining whether a well site is a wellhead only well site.”) because major production and processing equipment is also referenced in section 60.5397b(g)(1)(iii)(D) for purposes beyond determining whether a well site is a wellhead only site. The commenter therefore recommends that qualifier be eliminated. EPA should also add language to ensure that all types of storage vessels are included.



Response II-4-12: The EPA disagrees with the commenter that it should remove the wellhead only well site qualifier from the definition of major production and processing equipment. The EPA believes this is a necessary inclusion in order to ensure the requirements that apply for fugitive emissions monitoring are clear. The EPA agrees that it is appropriate to include all types of storage vessels in the definition. The EPA is finalizing the following definition of major production and processing equipment, which also includes the addition of control devices, natural gas-driven process controllers, natural gas-driven pumps, and tank batteries.

*Major production and processing equipment* means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site.

Comment: Commenter (2288-Department of Environmental Quality (NDDEQ)) notes that North Dakota state law requires that any emission of organic compound gases and vapors, except from an emergency vapor blowdown system or emergency relief system be controlled by a flare or an equally effective control device as approved by the NDDEQ. As such, even well sites with minimal emissions are required to have an operating control device onsite to control those emissions as well as to act as a backup in case there is an upset that would temporarily generate more significant emissions. It appears that EPA's supplemental proposal would count any such control device located at a well site as major production and processing equipment" 40 CFR 60.5397c(g)(1)(iii)(B), making the well site subject to more stringent monitoring and reporting requirements. The commenter requests that control devices that are not being used to comply with the requirements in the supplemental proposal be excluded from the definition of control devices for the purposes of determining rule applicability. The commenter does not want operators to encounter a situation where they are only subject to the supplemental proposal due to compliance with a previously existing state requirement.

Response II-4-13: The EPA understands the commenter's concerns, however, EPA is finalizing a definition of major production and processing equipment that includes control devices. Control devices, and other major production and processing equipment specified in §60.5397b(g)(1)(iv) and §60.5397c(g)(1)(iv) are sources individually are known sources of large emissions and emissions can leak from this equipment in substantial quantities if not functioning properly. Fugitive emissions components affected facilities located at well sites or centralized production facilities that have a control device would be subject to the requirements in §60.5397b and §60.5397c regardless of any separate requirements that the control device may or may not be subject to.

#### 4.1.2.9 Tank Battery

Comment: Commenter (2433-EDF et al) states for the definition of tank battery, EPA should clarify that if a tank battery exists at or near a well site, it is considered part of the well site for purposes of the fugitive emissions standards in sections 60.5397b and 60.5398b. EPA must clarify that tank batteries are subject to fugitive monitoring requirements regardless of where they are located, including tank batteries that are not part of a centralized production facility.

Response II-4-14: The EPA disagrees with the commenter. The definition of tank battery for the purposes of storage vessel applicability is unrelated to the scope of fugitive emissions at well sites, centralized production facilities, or compressor station sites. The fugitive emissions components affected facilities requirements in §60.5397b and §60.5398b and the definition of fugitive emissions components already include how to determine which components on storage vessels are included in the fugitive emissions monitoring and repair program.

#### 4.1.2.10 Definition of Centralized Production Facility

Comment: Commenters (2326-AXPC, 2433-EDF et al.) provide recommendations for revisions to the definition of centralized production facility.

Commenter (2326-AXPC) states the definition is important because requirements may differ if an affected facility is located at a well site or a centralized production facility. For example, reciprocating compressors located at a well site are not affected facilities, while those located at centralized production facility are affected facilities. EPA's definition of a well site does not provide complete information for an operator to determine if a location is a well site or a centralized production facility. The commenter requests that EPA clarify that a centralized production facility is a facility serving wells in which all wells are located off-site (*i.e.*, not on the same location as the centralized production facility). EPA's discussion of centralized production facilities in the November 2021 proposal does not make clear why EPA chose to define a centralized production facility as one servicing any offsite well, rather than a centralized facility receiving liquids from exclusively offsite wells.

Commenter (2428-API) suggests EPA add clarification to the definition for centralized production facility that addresses custody transfer.

Commenter (2433-EDF et al) recommend eliminating words that could support overly narrow interpretations of what constitutes a centralized production facility. The commenter recommends encompassing any site used to gather any produced hydrocarbons, again to prevent overly narrow interpretations. If EPA does not eliminate the word "offsite" from this definition, it must clarify that tank batteries at or near well sites are part of the well site fugitive emissions component affected facility. The commenter recommends the following changes:

*"Centralized production facility means one or more storage vessels and all equipment at a single surface site used to gather, ~~for the purpose of sale or processing to sell,~~ crude oil, condensate, produced water, ~~or~~ intermediate hydrocarbon liquid, or any other produced hydrocarbons, from one or more ~~offsite~~ natural gas or oil ~~production~~ wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. ~~Process vessels and process tanks are not considered storage vessels or storage tanks.~~ A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."*

Response II-4-15: In the November 2021 Proposal, the EPA determined that it was appropriate to include a definition of a centralized production facility to clearly distinguish between well sites and centralized production facilities (where liquids are received from at least one well site located offsite). The EPA provided extensive rationale for how the proposed definition of a

centralized production facility was developed at that time.<sup>19</sup> The EPA did not modify the definition in the December 2022 Supplemental Proposal. Further, the EPA did not propose to amend the definition of “well site,” except to remove the criteria for tank battery surface sites, which was being replaced (and expanded) with the definition of centralized production facility.

In response to one commenter’s request that EPA clarify that a centralized production facility is a facility serving wells in which all wells are located offsite (*i.e.*, not on the same location as the centralized production facility), the EPA disagrees, for the following reasons. First, the EPA believes that the proposed definition of “centralized production facility” was not clear for a facility receiving liquids from both on-site and offsite wells, as the proposed definition of centralized production facility was silent on the presence of on-site wells. Further, the proposed definition of “well site” was “one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well,” which could overlap with the definition of “centralized production facility” if the “centralized production facility” receives liquids from both on-site and offsite wells.

Next, the EPA notes that the proposed “modification” provisions at 40 CFR §60.5365b(i)(2) for “centralized production facility” clearly anticipated that an on-site well may be present at an existing centralized production facility, because the modification actions include the drilling of an on-site well, or the hydraulic fracturing or refracturing of an on-site well. To address the overlap that the proposed definitions of well site and centralized production facility created, the EPA is finalizing the following definitions for centralized production facility and well site.

*Centralized production facility* means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. The centralized production facility also may include one or more on-site wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

*Well site* means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. If the surface site also receives liquids from one or more off-site natural gas or oil production wells, the surface site is a centralized production facility, not a well site.

Regarding the comment that the proposed definition of centralized production facility could result in overly narrow interpretations, the EPA believes that the concepts of on-site vs offsite are necessary, as described above, to avoid confusion where two definitions may appear to apply. The changes should not result in a gap, where the fugitive emissions standards do not apply. A tank battery located near well sites which receives liquids from at least one offsite well is a centralized production facility. If all of the wells are on-site, the site is a well site. The definition of fugitive emissions component clearly states that components at a centralized production

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<sup>19</sup> 86 FR 63183-63185 (November 15, 2021).

facility and well site are included in the definition. Regarding the elimination or addition of other terms in the definition of “centralized production facility” that the commenter suggested, the commenter did not provide rationale as to why these changes are necessary and the EPA is not making these changes.

Regarding one commenter’s recommendation to address custody transfer in the definition centralized production facility, EPA included language in §60.5365b of the final rule that facilities located inside and including the Local Distribution Company (LDC) custody transfer station are not subject to this subpart.

### **4.1.3 Proposed BSER**

#### **4.1.3.1 General Comments**

Comment: Commenters (2248-NDPC, 2433-EDF et al.) express general support of the proposed BSER based on OGI monitoring.

Commenter (2458-MiQ) notes that based on their experience with its methane certification process, it supports the supplemental proposal’s frequency for OGI and AVO surveys and monitoring. The commenter recommends that the frequency of and monitoring requirements for OGI and AVO technologies and practices be updated annually based on available research.

Commenter (2248-NDPC) states before NSPS OOOOa, the oil and natural gas industry has been conducting OGI camera surveys and has learned much about fugitive emission leaks, their causes, and potential mitigation. As such, the OGI camera is a sustainable methane detection technology in North Dakota, especially with the challenges not present in, or significantly different than, other basins throughout the United States, such as inclement and harsh winter conditions presenting challenges precluding the use of a variety of methane detection technologies.

Commenter (2433-EDF et al.) states building from extensive experience, past regulations, and the experience of leading states, EPA has appropriately proposed leak detection and repair using OGI cameras as the best system of emission reduction for addressing fugitive emissions. OGI is a proven technology that has now been deployed for detecting and mitigating fugitive emissions from oil and gas operations for well over a decade.<sup>20</sup> EPA and other regulators have long relied on OGI monitoring because of its proven ability to detect emissions from a wide range of equipment and its ability to precisely pinpoint emission sources that can then be prioritized for repair.<sup>21</sup> This technology has been extensively tested and evaluated in the field,<sup>22</sup> and it has also

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<sup>20</sup> See, e.g., Reg’l Air Quality Council, RAQC Announces Optical Gas Imaging Camera Loan Program (April 23, 2012), [https://raqc.org/regional\\_air\\_quality\\_council\\_announces\\_optical\\_gas\\_imaging\\_camera\\_loan\\_prog/](https://raqc.org/regional_air_quality_council_announces_optical_gas_imaging_camera_loan_prog/).

<sup>21</sup> See Teledyne FLIR, Optical Gas Imaging Regulations in the United States and Europe, <https://www.flir.com/discover/instruments/gas-detection/optical-gas-imaging-regulations-in-the-united-states-and-europe/> (last visited Feb. 11, 2023).

<sup>22</sup> See, e.g., Daniel Zimmerle et al., Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions, 58 Env’t Sci. Tech. 11506 (2020), <https://pubs.acs.org/doi/10.1021/acs.est.0c01285>; Seth N. Lyman et al., Aerial and ground-based optical gas imaging survey of Uinta Basin oil and gas wells, 7 Elementa: Sci. of the Anthropocene 43 (2019), <https://online.ucpress.edu/elementa/article/doi/10.1525/elementa.381/112514/Aerial-and-ground-based-optical-gas-imaging-survey>.

been deployed and used successfully by operators for years.<sup>23</sup>

Commenter (2433-EDF et al) OGI cameras have a very low detection threshold, meaning they are sensitive and can detect small leaks that other technologies miss. As proposed, OGI cameras would be required to have a 100% detection limit of 60 grams per hour. This is far more sensitive than the technologies that may be permitted under the alternative options, which only require the ability to detect emissions ranging from 1 to 30 kg/hr. This means that when used with the same frequency and coverage, OGI will always be more effective at reducing emissions because it will detect all the same large emissions and the portion of smaller emissions that are below the detection threshold of less sensitive technologies. In addition, OGI can almost always immediately pinpoint the emissions source, while alternative options may require a follow up on site survey to locate the emission source before a repair can be attempted. Technologies with higher detection thresholds will always miss a certain fraction of smaller emissions and therefore cannot mitigate certain emissions that OGI can, regardless of frequency.

Commenter (2433-EDF et al) continues, LDAR programs using OGI cameras are a highly effective, low cost, and proven means for reducing fugitive emissions. Numerous studies have shown that over time and with repeated inspections, OGI programs reduce emissions and also help to prevent large emission events.<sup>24</sup> Studies have indicated that such LDAR programs are highly effective—some finding that more than 90% of leaks remained fixed a year later.<sup>25</sup> The same study found that “emissions reduced by 44% across all 8 facilities between the first and second LDAR survey,” similar to EPA and Environment and Climate Change Canada’s assumption that an annual OGI-based LDAR survey will reduce emissions by 40%.<sup>26</sup> However, it also found that each individual survey reduced a site’s overall fugitive emissions by only 22% on average because of new leaks that occurred afterwards, indicating that “frequent LDAR surveys might be necessary for long-term emissions management.”<sup>27</sup>

Commenter (2433-EDF et al) states EPA’s assumptions about the effectiveness of OGI are supported by recent data and FEAST modeling. In Colorado for example, instrument-based monitoring (typically with OGI cameras) inspections found 90% of leaks, despite constituting just 5% of total inspections in 2020<sup>28</sup> Based on 2019 annual data, 89% of leaks were found with instrument-based monitoring. Studies have produced similar results, for example finding that

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<sup>23</sup> Jonah Energy, for example, has used this technology since 2005 to reduce its emissions by 75%. See FLIR Media, Optical Gas Imaging at Jonah Energy (May 2016), [http://www.flirmedia.com/MMC/THG/Brochures/OGI\\_014/OGI\\_014\\_EN.pdf](http://www.flirmedia.com/MMC/THG/Brochures/OGI_014/OGI_014_EN.pdf); Teledyne FLIR, Jonah Energy Reduces Fugitive Natural Gas Emissions by 75% Using FLIR OGI Camera (Feb. 2021), <https://www.flir.eu/discover/instruments/gas-detection/jonah-energy-reduces-fugitive-natural-gas-emissions-by-75-percent-using-flir-ogi-camera/>.

<sup>24</sup> Jiayang Wang et al., Large-Scale Controlled Experiment Demonstrates Effectiveness of Methane Leak Detection and Repair Programs at Oil and Gas Facilities, EarthArXiv (2021) (non-peer reviewed preprint), <https://eartharxiv.org/repository/view/2935/>; Arvind P. Ravikumar et al., Repeated leak detection and repair surveys reduce methane emissions over scale of years, 15 Env’t Rsch. Letters 034029 (2020), <https://iopscience.iop.org/article/10.1088/1748-9326/ab6ae1/pdf> [hereinafter Ravikumar 2020].

<sup>25</sup> Ravikumar 2020, supra note 104.

<sup>26</sup> Id.

<sup>27</sup> Id.

<sup>28</sup> Colo. Dep’t Pub. Health & Env’t, 2020 LDAR Annual Reports (Regulation 7 Section XVII), <https://cdphe.colorado.gov/2020-ldar-annual-reports-regulation-7-section-xvii> (last visited Feb. 11, 2023).

“over 80% of emissions can be detected [with OGI] from an imaging distance of 10 m.”<sup>29</sup> EPA has long assumed an 80% mitigation effectiveness for quarterly OGI and has updated that number to 77% in the supplemental proposal based on FEAST modeling results.<sup>30</sup> This assumption is reasonable and aligns with the literature, EPA’s past practice, and our own assumptions derived from FEAST.<sup>31</sup>

Response II-4-16: The EPA acknowledges the support for the general BSER determination for fugitive emission components. The EPA is finalizing the BSER determination as proposed.

Comment: Commenter (2193-California Air Resources Board (CARB)) argues the present proposed structure creates different LDAR requirements for every different type of facility, which is likely to result in extreme difficulty with respect to enforcement and compliance due to the different rules for nearly every type of facility as well as a great deal of regulatory complexity in implementation. In contrast, California’s Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities (California Code of Regulations, Title 17, Sections 95665-95677) has the same LDAR requirements regardless of the facility type. Specifically, components in place after January 1, 2018, require quarterly Method 21<sup>32</sup> inspections.<sup>33</sup> OGI is permissible for leak detection and/or monitoring but may not be used in place of quarterly Method 21 inspections and the time limitations for leak repair are also applied evenly across the facilities.<sup>34</sup> This method has worked very well in California and enforcement of the regulation has proceeded smoothly. Amending this portion of the proposed Supplemental Rule to require quarterly Method 21 inspections, or alternatively, bimonthly advanced technology inspections with annual OGI monitoring, regardless of the type of facility, would ensure a streamlined process for states to implement and enforce in their plans.

Commenter (2193-CARB) argues to amend this portion of the proposed Supplemental Rule to require quarterly Method 21 inspections, or alternatively, bimonthly advanced technology inspections with annual OGI monitoring, regardless of the type of facility, would ensure a streamlined process for states to implement and enforce in their plans.

Response II-4-17: We disagree that a one-size-fits-all approach is appropriate for BSER analysis. A reasonable portion of the costs to monitor a site stem from fixed charges for monitoring crew to travel to the site and charges related to monitoring equipment rental fees. For facilities with few fugitive emission components, it is common that no new leaks will be present at the site

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<sup>29</sup> Arvind P. Ravikumar et al., Are Optical Gas Imaging Technologies Effective For Methane Leak Detection?, 51 Env’t Sci. Tech. 718 (2017), <https://pubs.acs.org/doi/10.1021/acs.est.6b03906>.

<sup>30</sup> U.S. Env’t Protection Agency, Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, or Modified Sources and Emissions Guidelines for Existing Sources: Oil and Gas Climate Review at 231, Table 7 (Nov. 2022) (Doc. ID No. EPA-HQ-OAR-2021-0317-1566) [hereinafter Supplemental RIA].

<sup>31</sup> See Arvind P. Kumar, FEAST: US – Alternative LDAR Programs for Representative US O&G Production Facilities (Jan. 2022) (included as Attachment L to 2022 Joint Environmental Comments, supra note 1).

<sup>32</sup> 40 CFR §60, Appendix A7: “Method 21: Determination of Volatile Organic Compound Leaks” The summary provides that “a portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in section. 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.”

<sup>33</sup> 17 Cal. Code Regs. 95669(g) (2018).

<sup>34</sup> Id.

during quarterly or even semi-annual monitoring events. When considering the fixed costs of a monitoring event and the lower emission reductions achieved at sites with few equipment components (small sites), we determined that quarterly OGI (or Method 21) monitoring is not cost effective. The CAA at section 111(a)(1) specifically states that a “standard of performance” must reflect “...the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” As such, the EPA must consider the costs of achieving the emission reductions. Because the costs of achieving the emission reductions varies significantly based on the size of the site (number and types of fugitive emission components), we determined BSEER and develop different standards of performance for production facilities of different sizes.

Comment: Commenter (2410-California Office of the Attorney General et al.) states EPA’s revised approach seems to be largely based on Colorado’s leak detection and repair (LDAR) program, which has been in place since 2014, and requires each well site to calculate its baseline methane emissions for all of the equipment at the well site, the number of fugitive emissions components associated with each piece of equipment, and the site-specific gas composition. Colorado’s regulatory approach to leak detection and approved instrument monitoring method (AIMM) inspection of well production facilities is multi-layered. First, as of a December 2021 program update, all new well production facilities must conduct monthly AIMM inspections unless they are constructed and operated with specified design features that reduce the potential for emissions, such as constructing the site without hydrocarbon liquid storage tanks (i.e., tankless design).<sup>35</sup> Existing well production facilities must conduct inspections at a frequency that depends on the actual, uncontrolled VOC emissions from a storage tank.<sup>36</sup> Inspection frequencies range from annual, for the smallest sites, to monthly for the largest sites.<sup>37</sup> Colorado also incorporates stricter standards for operations in disproportionately impacted communities and, in some cases, where the operations are located within 1,000 feet of an occupied area.<sup>38</sup>

Commenter (2410-California Office of the Attorney General et al.) adds alternatively, EPA may consider streamlining the proposed LDAR program by requiring the same LDAR requirements for all facilities. California’s regulation requires quarterly LDAR inspections at all new and existing well sites without exemptions, and operators in California—including large and small entities—have complied with the requirements for many years now.<sup>39</sup> Specifically, components in place after January 1, 2018 require quarterly EPA Method 21<sup>40</sup> inspections.<sup>41</sup> OGI is permissible for leak detection and/or monitoring but may not be used in place of quarterly EPA

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<sup>35</sup> 5 Colo. Code Regs. § 1001-9:D.II.E.4.e-f (adopted Dec. 17, 2021).

<sup>36</sup> Id. § II.E.4.g. tbl. 4.

<sup>37</sup> Id.

<sup>38</sup> Colo. Rev. Stat. § 24-4-109.

<sup>39</sup> See Cal. Code Regs., tit. 17, § 95669.

<sup>40</sup> 40 C.F.R. § 60, Appendix A7 (“Method 21: Determination of Volatile Organic Compound Leaks”). The summary of Method 21 provides that “a portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in section 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.” Id.

<sup>41</sup> Cal. Code Regs., tit. 17, § 95669(g) (2018).

Method 21, and the time limitations for leak repair are also applied evenly across the facilities.<sup>42</sup> Similarly, New Mexico's recently promulgated regulations apply LDAR requirements to all wells with no exceptions, with every well to receive leak inspections at least once a year, and larger, potentially higher emitting wells receiving semiannual or quarterly inspections.<sup>43</sup> And New York's recently adopted regulations require semiannual LDAR at all well sites with no exceptions.<sup>44</sup> Uniformity may facilitate and ensure that states are able to implement and enforce these requirements in their plans.

Response II-4-18: The EPA appreciates the summary of different state requirements. We note that our proposed provisions are very similar to those of New Mexico's. As noted in the immediately previous comment and response, we determined, based on the authority and requirements in section 111 of the CAA, that the fugitive emission component monitoring requirements should be different for differently-sized facilities.

Comment: Commenter (2180-Pennsylvania Department of Environmental Protection (DEP)) recommends the frequency of LDAR inspections should be as follows:

- Monthly AVO inspections at all affected facilities;
- Semiannual instrument-based LDAR inspections for well sites and remote pigging stations emitting less than 2.7 tpy of VOC;
- Quarterly instrument-based LDAR inspections for well sites and remote pigging stations emitting equal to or greater than 2.7 tpy of VOC, and for gathering and boosting stations, natural gas processing plants, and transmission stations.

Commenter (2180-DEP) notes Pennsylvania has required similar sources to perform monthly AVO inspections and quarterly or semiannual instrument-based LDAR inspections since 2013.

Response II-4-19: In EPA's November 2021 proposal, EPA proposed a monitoring approach using a potential emissions threshold for subcategorizing facilities for the fugitive emissions requirements. The EPA decided that there were several practical issues related to using such an emissions threshold (*e.g.*, should it be based on default emission factors versus actual emissions; what should happen if a facility has a large event – does this trigger into more frequent monitoring and, if so, how long?). The EPA determined that using the number of major equipment at the well site provided a more clear and appropriate method by which to subcategorize facilities relative to the fugitive emissions requirements. The EPA is finalizing the fugitive emission components monitoring and repair requirements as proposed.

Comment: Commenter (2394-Earthworks) provides detailed results from a number of case studies and field surveys in several states in order to track the progress of oil and gas regulations. The commenter provides information and results on case studies conducted in Colorado from which the commenter notes that despite the adoption of stricter oil and gas regulations in Colorado, pollution from the industry is still pervasive and persistent. The commenter provides a

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<sup>42</sup> Id.

<sup>43</sup> See New Mexico Administrative Code 20.2.50, at 20.2.50.16, available at <https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2022/07/Oil-and-Gas-SectorOzone-Precursor-Pollutants-Final-rule-20.2.50-NMAC-06Jul22.pdf>.

<sup>44</sup> 6 New York Codes, Rules and Regulations (NYCRR) 203-7.2(a) (effective Mar. 3, 2022).



similar summary based on a case study conducted in Pennsylvania, which the commenter believes demonstrates a clear need for frequent monitoring of emissions at every oil and gas well pad, including those previously overlooked due to production volume or size. Case studies performed in Texas where the commenter conducted thousands of individual site visits and submitted over 400 complaints with OGI video as evidence to various agencies, including the TCEQ. Based on those case studies, the commenter reports that there is an alarming failure to protect public health and safety and local environments. The commenter also notes that it has documented air pollution and emissions in New Mexico, reporting results of field surveys to the regulatory agency and highlights enforcement shortfalls, including the lack of appropriate capacity to enforce current rules and regulations. More information on the specific case study findings is provided in the commenter's letter.

Response II-4-20: The EPA acknowledges the information provided by the commenter and notes that it is aware of information available from multiple case studies in various areas reporting on results from different fugitive emissions monitoring and repair programs. The EPA is finalizing requirements that update, strengthen, and expand on the current requirements under CAA section 111(b) for methane and VOC emissions from sources that commenced construction, modification, or reconstruction after December 6, 2022

#### 4.1.3.2 AVO/OGI/Method 21

Comment: Commenters (2168-INOGA, 2177-Ute Indian Tribe, 2181-Ute Indian Tribe of the Uintah and Ouray Reservation, 2217-Religious Action Center of Reform Judaism, 2433-EDF et al., 2248-North Dakota Petroleum Council (NDPC), 2458-MiQ) appreciate EPA's consideration and implementation of AVO inspections to identify emissions sources. The commenters believe this is a cost-effective method to identify when there is a leak, so it can be identified and repaired.

Commenter (2433-EDF et al.) is supportive of AVO because regular site visits and upkeep are important at all sites and will help to prevent and mitigate fugitive emissions and equipment failures. Regular AVO inspections can also help secure additional emissions reductions from large and very obvious equipment failures. The proposed AVO requirements can help ensure operators actually address issues they find at sites indicating a potential leak rather than turning a blind eye. Especially at marginal and declining sites, lack of maintenance can lead to persistent and long-lasting leaks, and can sometimes result in major failures.<sup>45</sup> AVO can therefore serve an important additional purpose aimed at site hygiene and preventative maintenance that is not necessarily encompassed by OGI or periodic screening, which are both aimed at reacting after a problem has occurred.

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<sup>45</sup> Jacob Deighton et al., Measurements show that marginal wells are a disproportionate source of methane relative to production, 70 J. Air Waste Mgmt. Assoc. 1030, 1030–42 (2020), <https://www.tandfonline.com/doi/epdf/10.1080/10962247.2020.1808115?needAccess=true&role=button> (finding that “the main driver of emissions from the wells visited is neglect. The state of maintenance at these wells was poor. Often, pumpjacks, tanks, and other infrastructure were rusty and sometimes appeared to have temporary fixes to just keep the well mechanically operational. . . . Some wells looked like they had not been serviced in years.”)

Commenter (2433-EDF et al) argues, to ensure the preventative value of AVO is realized, EPA should alter the regulatory language to require action when “evidence of a potential leak or likely future leak is found at any time.”

Commenter (2433-EDF et al) notes regulatory exemptions can result in irresponsible operations and business models that aim to keep declining wells in production beyond their useful lives in order to avoid plugging costs and exploit tax benefits.<sup>46</sup> This can lead to rusted, overgrown, and unmaintained sites that leak methane, create dangerous conditions, and are prone to orphanage.<sup>47</sup> Requiring the responsible operator to inspect these sites and fix visible problems will help combat these issues while disincentivizing business models centered on accumulating and neglecting declining sites.

The commenter’s (2433-EDF et al) compliance report analysis found much shorter OGI survey and travel times in reported data. This underscores that EPA is likely overestimating those same figures (and thus costs) in its assumptions about AVO as well.<sup>48</sup> Indeed, travel times for AVO surveys are likely to be the same as for OGI, and inspection times will be shorter for AVO than OGI.

Response II-4-21: The EPA is finalizing fugitive emissions monitoring requirements that requires different AVO inspection frequencies depending on the type of site; either by itself, or in combination with regular OGI surveys. Inspections using AVO is a cost-effective method to identify when there is a leak, but is, as discussed in the December 2022 Supplemental Proposal preamble<sup>49</sup> not sufficient for well sites with additional fugitive emissions components such as connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO. See section X.A.1.a.ii for the final standards for all well sites and centralized production facilities, which includes quarterly AVO for single wellhead only well sites and small well sites, and a combination of AVO and OGI monitoring for multi-wellhead only well sites and well sites with major production and processing equipment.

Comment: Commenter (2433-EDF et al) argue EPA’s OGI and AVO cost-effectiveness assumptions are reasonable and conservative. Fugitive monitoring and repair with OGI cameras is low cost, with a commonly cited per-site inspection cost of \$600.<sup>50</sup> With new regulatory requirements, company-set emission reduction targets, and rapid growth in the methane

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<sup>46</sup> See, e.g., Zachary R. Mider & Rachel Adams-Heard, *An Empire of Dying Wells*, Bloomberg (Oct. 2021), <https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/>.

<sup>47</sup> Deighton et al., *supra* note 123, at 1030–42.

<sup>48</sup> Supplemental TSD, *supra* note 121, at 5–18 (“a travel time of 1.25 hours round trip was assumed at the same hourly rate for operators as is used for the development of a monitoring plan and other actions. Inspection times ranging from 15 minutes (single wellhead only well sites) to 1 hour (centralized production facilities) to account for the added complexity at larger sites, were assumed.”)

<sup>49</sup> 86 FR 74732 (December 6, 2022).

<sup>50</sup> U.S. Env’t Protection Agency, EPA’s Methane Detection Technology Virtual Workshop Transcript Day Two at 24 (Aug. 24, 2021) (Doc. ID No. EPA-HQ-OAR-2021-0317-0181).

mitigation sector,<sup>51</sup> it is likely that OGI monitoring will become even lower cost in the coming years and prior to the initial date for existing source compliance.

Commenter (2433-EDF et al) states in this supplemental proposal, EPA's cost assumptions remain largely unchanged from the November 2021 proposal. There, EPA examined three elements of OGI monitoring costs: (1) periodic monitoring for leaks; (2) repair of leaks identified; and (3) documentation of the detection and repair activities. EPA breaks these down into specific cost components that include: reading of the rule and instructions; development of a company-wide fugitives monitoring plan; recordkeeping database system set-up fee; cost for OGI monitoring (OGI camera survey); repair costs; costs to resurvey; annual recordkeeping database maintenance/license fee; additional recordkeeping/data management costs; and preparation of annual reports. EPA assumes a fugitive monitoring program will cover an average 22-site area and then distributes costs across sites. EPA uses these cost estimates and the reductions achieved by various inspection frequencies to estimate cost-effectiveness.

Commenter (2433-EDF et al) analyzed EPA's assumptions underlying the OGI cost estimates and cost-effectiveness analysis.<sup>52</sup> The commenter found that various cost components included double counting—meaning the same cost was accounted for in two or more cost components. EPA's 2021 analysis of OGI costs for well sites overestimated costs by double counting reporting, recordkeeping and data management, and other costs such as travel time. In addition, EPA relies on averages of API data that overestimate costs for recordkeeping and data management. The commenter reviewed compliance reports from EPA's WebFIRE database and found that most reported travel and survey times were far shorter than EPA's assumptions.

Commenter (2433-EDF et al) presents an updated and fully comprehensive cost analysis based on their review of data from over 16,000 upstream OGI surveys included in compliance reports submitted under NSPS OOOOa.<sup>53</sup> The commenter downloaded and reviewed all of the 26,724 annual compliance reports submitted to EPA from 2017 to early 2021 via the WebFIRE database. This timeframe captures the most recent reporting using an EPA template that includes survey time data; after March 31, 2021, annual compliance reports submitted to EPA do not include survey times.

Commenter (2433-EDF et al) states these annual compliance reports shows an average combined travel and survey time of 1.75 hours, much less than EPA's 2.5-hour assumption. The commenter also found a median survey time of 30 minutes and an average of 60 minutes.<sup>54</sup> This supports and aligns with EPA's use of a 30-minute survey time in its recent cost analysis. The average is affected by a small number of surveys that took over 90 minutes, as presented in the

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<sup>51</sup> See Marcy Lowe, Datu Rsch., Advanced Methane Monitoring: Gauging the Ability of U.S. Service Firms to Scale Up (July 22, 2021), [http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey\\_DatuResearch\\_8-10-2021.pdf](http://blogs.edf.org/energyexchange/files/2021/08/Advanced-Methane-Monitoring-Survey_DatuResearch_8-10-2021.pdf).

<sup>52</sup> 2022 Joint Environmental Comments, *supra* note 1, at 72–84.

<sup>53</sup> For a complete description of the methodology, see Env't Def. Fund, OOOOa Compliance Report Analysis Methodology (included as Attachment B).

<sup>54</sup> See OGI Survey Time Analysis Final (included as Attachment C), for a full printout of the figures.

histograms included in with the full attached analysis. The results of this analysis are presented in the Figures 1 and 2 of the commenter's letter.<sup>55</sup>

Commenter (2433-EDF et al) notes their analysis also examined all the available information on travel time between surveys. For the upstream LDAR surveys with reported start- and end-time data in the dataset, the commenter looked at surveys conducted by the same surveyor at multiple locations on the same date (*i.e.*, at least two surveys conducted on the same date by the same surveyor). They then calculated the time elapsed between the end of one survey and the start of the next. The average time between surveys that occurred on the same date by the same surveyor was 43 minutes.<sup>56</sup> Figures 3 and 4 show the distribution of times between surveys (*e.g.*, there were 2,905 occurrences in the dataset when the elapsed time between the end of one survey and the beginning of the next was less than 15 minutes).

Commenter (2433-EDF et al) states given that their analysis encompassed every reported survey time and all of the available information on travel, EPA should use both the 30 minute median survey time and 43 minute average travel time in its analysis, for a total combined time of 73 minutes. Sites subject to OOOOa fugitive monitoring are likely more complex than the average site, and the commenter expects that survey times for OOOOb/c sites would typically be shorter.

Commenter (2433-EDF et al) states using their revised survey and travel time, as well as a revised labor rate and recordkeeping and reporting costs, which avoid double counting as described in their initial comments,<sup>57</sup> the commenter recreated EPA's cost-effectiveness tables from the TSD accompanying the supplemental proposal.<sup>58</sup> For each model plant, the commenter analyzed the single pollutant cost-effectiveness of OGI monitoring under six scenarios:

- Scenario 1m: includes revised median survey and average travel time, labor rate, and recordkeeping/reporting costs;
- Scenario 2m: includes revised median survey and average travel time, and labor rate; and
- Scenario 3m: includes revised median survey and average travel time.
- Scenario 1a: includes revised average survey and travel time, labor rate, and recordkeeping/reporting costs;
- Scenario 2a: includes revised average survey and travel time, and labor rate; and
- Scenario 3a: includes revised average survey and travel time.<sup>59</sup>

Commenter (2433-EDF et al) states for the single wellhead-only model plant, the commenter finds that semiannual OGI is within the range EPA considers cost-effective under scenarios 1m and 1a using both leak rate assumptions (0.5% and 1% leak rates). For both the multi-wellhead-only and the well site and centralized production facility model plants, the commenter finds that quarterly OGI is cost-effective and incrementally cost-effective under all scenarios. These

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<sup>55</sup> For full compliance report analysis, see Env't Def. Fund, OOOOa Compliance Report Analysis Full Workbook (Attachment D).

<sup>56</sup> See OGI Travel Time Analysis Final (included as Attachment E) for a full printout of the figures.

<sup>57</sup> 2022 Joint Environmental Comments, *supra* note 1, at 72–84.

<sup>58</sup> See U.S. Env't Protection Agency, Supplemental Background and Technical Support Document for the Proposed NSPS and EG, Tables 5–10 to 5–17b (Oct. 2022) (Doc. ID. No. EPA-HQ-OAR-2021-0317-1578) [hereinafter Supplemental TSD].

<sup>59</sup> These tables are included with our comments as PDF's located in the Revised OGI Cost Effectiveness Tables (included as Attachment F) and each is also accompanied by the associated revised cost evaluation spreadsheet with revisions and notes in green.

findings support the reasonable cost of EPA's proposed standards and also support the commenter's recommendations for more frequent monitoring at certain site types.

Response II-4-22: The EPA acknowledges the information and analysis the commenter has conducted. The EPA has undertaken a significant effort to estimate the costs of various fugitive emissions monitoring and repair program, which has included information from NSPS OOOOa compliance reports, industry-provided information, and other sources. The EPA discussed extensively the inputs to the costs of the program in the 2021 TSD, and described additional edits to the costs in the December 2022 Supplemental Proposal.<sup>60</sup>

The EPA determined that due to the nature of emissions sources located at single wellhead only well sites (including large emission sources identified in the DOE Study), identification of emissions would not require the use of OGI, but AVO inspections would easily identify these sources. Therefore, the EPA evaluated a periodic AVO inspection and repair program and found that quarterly AVO inspections for fugitive emissions from single wellhead only well sites was cost-effective.

Consistent with the commenter's conclusion, the EPA also found that quarterly OGI monitoring at multi-wellhead only well sites and well sites with major production and processing equipment and centralized production facilities are cost-effective. But, for multi-wellhead only well sites, as discussed in the December 2022 Supplemental Proposal, the EPA did not find the incremental cost-effectiveness of moving from semiannual OGI monitoring to quarterly OGI monitoring to be reasonable. However, the EPA analyzed the possibility of additional monitoring in the form of AVO inspections outside of semiannual OGI monitoring for multi-wellhead only well sites, and found that the addition of quarterly AVO inspections would be cost-effective as well. Note that under the scenario of evaluating quarterly AVO inspections, only two AVO inspections would be required outside of the OGI surveys, thus the inspection costs would be half what is estimated for quarterly AVO inspections. The EPA also evaluated the addition of AVO inspections in addition to quarterly OGI monitoring for well sites with major production and processing equipment and centralized production facilities. The EPA found that the addition of bimonthly AVO in combination with quarterly OGI monitoring would be cost-effective in that case. The EPA is finalizing the fugitive emissions monitoring requirements as proposed under the December 2022 Supplemental Proposal.

Comment: Commenters (2202-Texas Oil and Gas Association (TXOGA), 2403-The Petroleum Alliance of Oklahoma (PAO) supports the removal of the requirement to comply with Appendix K for well sites and centralized production facilities.

Commenter (2202-TXOGA) requests that EPA not incorporate Appendix K as the OGI monitoring protocol for NSPS OOOOb and EG OOOOc. The commenter provides that the EPA acknowledges that extensive comments were filed on this issue after the November 2021 proposal. The commenter acknowledges that EPA's December 2022 supplemental proposal appears to have been responsive to comments/concerns raised in its November 2021 proposal. Indeed, the commenter states that the December 2022 supplemental proposal states that EPA is "not including a requirement to conduct OGI monitoring according to the proposed appendix K . . . as" was stated in the November 2021 proposal.<sup>1</sup> Instead, the commenter states that EPA is now

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<sup>60</sup> 87 FR 74727-74729 (December 6, 2022).

proposing “to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21.” While the commenter appreciates that EPA has incorporated their comments in regard to OGI monitoring, they do not agree with the proposed alternative approach of using NSPS OOOOb to accomplish the same.

Commenter (2403-PAO) states that they provided significant concerns with Appendix K in their comments on the November 2021 proposal. In the December 2022 supplemental proposal, the commenter acknowledges that the EPA is proposing to require OGI monitoring for well sites and centralized production facilities following the monitoring plan required in proposed 40 CFR 60.5397b instead of requiring the procedures being proposed in Appendix K for these sites. The commenter supports this change.

Response II-4-23: The comments are supportive on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenters (2167-West Virginia Surface Owners' Rights Organization, 2200-NuEnergy Operating Inc., 2314-Miller Energy Company, 2462-Cynthia Walter) question why EPA is not allowing other devices such as gas sniffers/meters as an alternative to detecting fugitive emissions.

Commenter (2167-West Virginia Surface Owners' Rights Organization) is concerned about the inadequacy of AVO inspections to detect methane leaks when it is so incredibly cheap and effective to use a meter capable of detecting methane. A simple search for "methane detector meters" on Amazon results in a wide choice of meters capable of detecting methane appearing starting at a price of only \$32. Perhaps some are only sensitive to explosive levels of methane, but one by Forensic for \$100 advertises it has a detection range from “0-10,000ppm”.

Commenters (2167-West Virginia Surface Owners' Rights Organization, 2462-Private Citizen) continue, an inspection using an actual meter is obviously much more effective than an olfactory inspection since methane has no odor unless the gas being produced has impurities. Worse, a visual inspection is not all that useful since methane is clear -- though if there is water standing in the equipment you can often see methane bubbling out of a well. Audio listening can sometimes tell a person there is a big leak, but lots of leaks are not large enough to make a sound.

Commenter (2167-West Virginia Surface Owners' Rights Organization) asks to determine the volume of the leak, would a FLIR camera be better, or a dynamic flux chamber, or testing using the inverse dispersion model? Yes. But not requiring testing with a handheld methane meter costing \$100 because they are not as good at testing volumes would be the epitome of letting the perfect interfere with the good. Whatever the size of the leak, it needs fixed, and often at the wells to which we are exposed it could be fixed with only a wrench.

Commenter (2167-West Virginia Surface Owners' Rights Organization) states the extent of the problem in West Virginia is demonstrated scientifically by a study done by Princeton and McGill

Universities.<sup>61</sup> They did a variety of testing in 13 counties in northern West Virginia. They tested 338 conventional vertical wells in those counties in West Virginia and found that 53% of active wells, 28% of unplugged inactive wells, and even 20% of plugged wells were leaking significant methane into the atmosphere. In particular they tested 79 active, conventional (vertical) wells by first using a handheld detector capable of detecting 10 ppm or more. If methane was detected at or above that level they then used either a flux chamber or inverse dispersion. They found that 53% of those wells were leaking 9 cubic feet of gas -- per hour. So testing even with just handheld meters can detect methane and could make a big impact on stopping fugitive methane emissions.

Commenter (2167-West Virginia Surface Owners' Rights Organization) note there are many small single wells owned by individual surface landowners in West Virginia. The commenter's Department of Environmental Protection counts 75,000 total wells in West Virginia, the vast majority of those being single wells on individual surface property owners. Methane leaking from these wells is just plain wasteful, deprives our members who are royalty owners of some royalties, deprives the state of severance taxes, contributes to climate change, and often stinks.

Commenter (2462-Cynthia Walter) also argues AVO inspections are not reliable because fugitive emissions could easily be invisible, have no smell, and the sounds can be masked by other equipment or road noise. In-person inspections of sites are important, however, to make sure monitoring equipment is in the correct place and to document that equipment is working or idle, and conditions are normal.

Commenter (2462-Cynthia Walter) provides an example, a researcher was contracted to compare air pollutants upwind and downwind from a compressor station adjacent to a water treatment facility for 130,000 people, Beaver Run Reservoir in Westmoreland Co., PA. Values were similarly low for all sensors. Later, the researcher was told that the compressor was not in use that week.

Commenter (2200-NuEnergy Operating Inc.) indicates there are alternative cost-effective solutions that could be performed during normal operation visits from company staff like daily or weekly AVO site visits and annual OGI with monthly AVO surveys with an inexpensive handheld gas meter. The commenter indicates that it is already performing leak surveys during routine visits, and requests guidance whether this would meet the EPA's desired increase of fugitive emissions monitoring.

Commenter (2200-NuEnergy Operating Inc.) additionally questions if gas sniffers could be used during inspections instead of costly OGI equipment. The commenter asks if increased AVO monitoring with inexpensive hand-held gas meters used by field operators during normal work routines be a cost-effective alternative to expensive OGI equipment.

Commenter (2314-Miller Energy Company) notes that the investment required to install fixed monitoring equipment on 600+ marginal wells would not be financially feasible. The commenter has a hands-on, low-tech approach to ensuring their operations are environmentally sound. The commenter's field staff visit sites daily and complete AVO inspections at each well and facility.

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<sup>61</sup> Available on the commenter's website: <https://wvsoro.org/a-study-by-scientists-conventional-vertical-wells-in-west-virginia/>.

If regular AVO inspections are not deemed adequate, the field staff may be able to utilize mobile devices on a reasonable schedule to confirm emissions are within regulation. The commenter encourages the EPA to consider low-cost solutions that would be sufficient for monitoring low-emission wells/facilities, specifically looking at mobile gas meters that can be used across the operation instead of fixed units per well.

Response II-4-24: The EPA acknowledges the commenter's remarks regarding gas sniffers and low-cost methane detectors. As specified in §60.5397b(g) of the final rule, techniques for determining fugitive emissions include AVO, Method 21 of appendix A-7 of 40 CFR part 60, or OGI. However, owners and operators can apply for an alternative means of emissions limitation for technologies that achieve an equivalent level of emissions reduction as the technologies in the final rule under §60.5399b of the final rule. In addition, the final rule at §60.5398b includes provisions for owners and operators to apply to use alternative technologies to meet the standards that apply to fugitive emissions components affected facilities. We do not expect low-cost methane detectors to be as sensitive as the required instrument monitoring alternatives (specifically Method 21) nor has EPA developed a method for use of these detectors. Operators may elect to use these as part of their AVO surveys to help find leaks; however, we are not requiring the use of low-cost methane detectors as part of the AVO program.

First, we disagree with commenters suggesting that AVO is completely ineffective. While we understand that pure methane is colorless and odorless, production facilities do not produce pure methane. The gas produced commonly includes trace compounds, like hydrogen sulfide or benzene and other aromatic hydrocarbons, that are readily identified by olfactory methods. Liquids are also commonly co-produced with natural gas and leaks of liquid containing fluids are readily identified by visual methods.

Second, for these low-cost methane detectors to identify appreciably more leaks than a typical AVO inspection, the operator would have to sniff each individual component at very close range, similar to Method 21, greatly increasing the time and costs associated with conducting AVO inspections. The cost of Method 21 monitoring is driven by the time needed to conduct the monitoring rather than the cost of the Method 21 instrument. Thus, we find that a requirement to effectively use low-cost methane detectors to identify fugitive emissions is not appreciably different than the instrument monitoring methods that we evaluated in our BSER analysis. We expect the instrument would be less accurate and sensitive, so it would find fewer leaks than the instrument methods we included in the rule, but it would be just as expensive to conduct as those methods. Therefore, we maintain our BSER determination that instrument monitoring be conducted at the frequency determined to be cost effective and that AVO monitoring be conducted at specified frequencies to enhance the instrument monitoring program.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2205-Kriebel Well Services, Inc., 2304-PIOGA) believe that EPA should support and recommend soap bubble tests as a cost-effective method second step to isolate the location of a leak after it has been identified by an AVO inspection. Soap bubble verification should also be an acceptable method to verify that a leak has been repaired. Soap bubble tests have been effectively used for decades for leak checks in residential and commercial buildings. The commenters believe that this method is just as effective at identifying leaks for oil and gas production assets, especially those that are not complex or do not cover a large area. Using soap bubbles does not require expensive equipment



and an operator with specialized training to be paid to travel to a well site, tank battery, or gas processing location, as EPA is currently proposing.

Response II-4-25: Similar to the allowance in NSPS OOOOa, EPA proposed to allow the use of a soap bubble test to verify that emissions from fugitive emissions components have been repaired. Method 21 allows a user to spray a soap solution on components that are operating under certain conditions (e.g., no continuous moving parts or no surface temperatures above the boiling point or below the freezing point of the soap solution) to determine if any soap bubbles form. If no bubbles form, the components are deemed to be operating with no detected emissions. We note that spraying soap solution to confirm whether a component has been repaired may not work for all fugitive emissions components, such as a leak found under the hood of the thief hatch since it would be difficult to apply the soap solution or observe bubbles. However, we believe that this alternative will provide some owners and operators a simple, low-cost way to confirm that a fugitive emissions component has been repaired. This would also allow the resurveys to be performed by the same personnel that completed the repairs instead of other certified monitoring personnel or hired contractors that would have to come back to verify the repairs. Therefore, we are finalizing the use of the alternative screening procedures specified in Section 8.3.3 of Method 21 for resurveying repaired fugitive emissions components, where appropriate.

#### 4.1.3.3 Equipment-Based Approach

Comment: Commenters (2036-National Parks Conservation Association (NPCA), 2236-Physicians for Social Responsibility Pennsylvania (PSR), 2303-National Tribal Air Association (NTAA), 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al., 2433-EDF et al, 2462-Cynthia Walter) express support for an equipment-based fugitive emissions monitoring approach and provide specific comments below.

Commenters (2036-National Parks Conservation Association (NPCA), 2303NTAA), 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al.) appreciate EPA's revised approach for fugitive emissions monitoring at all well sites based on the specific types of leak-prone equipment or equipment that can be the source of large emission events—such as flares, storage vessels, and pneumatic devices—rather than just well production.

Commenters (2236-PSR, 2433-EDF et al, 2462-Cynthia Walter) state the PTE is very hard metric to predict. Existing non-measurement-based estimation methods, like the PTE calculation in the initial proposal, tend to misrepresent emissions and, in particular, miss super-emitters. The commenters urge EPA to move toward an equipment-based approach where monitoring requirements depend on the presence of equipment at a site and that equipment's potential to leak or fail.

In their previous comments, commenter (2433-EDF et al) submitted extensive evidence outlining the serious problems with an approach that based monitoring requirements on potential emissions calculated by operators using an equation that did not adequately predict actual emissions nor account for equipment failures.<sup>62</sup>

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<sup>62</sup> 2022 Joint Environmental Comments, *supra* note 1, at 84–91.

Commenter (2433-EDF et al) states it is appropriate to base monitoring frequency on the presence of certain types of equipment at a site because such equipment has been commonly observed as the source of large emission events through numerous field studies. The presence of major equipment also indicates higher component counts, which correlate to a greater probability of fugitive emissions.

Commenter (2433-EDF et al) cites a study, Zavala-Araiza et al. (2017) explains that abnormal process conditions, both persistent or episodic, include “failures of tank control systems, malfunctions upstream of the point of emissions (for example, stuck separator dump valve resulting in produced gas venting from tanks), design failures (for example, vortexing or gas entrainment during separator liquid dumps) and equipment or process issues (for example, over-pressured separators, malfunctioning or improperly operated dehydrators or compressors).”<sup>63</sup> Another study by Lyon et al. found that emissions from tank vents and hatches accounted for roughly 90% of all detected hydrocarbon sources emitting more than 3–10 kg per hour.<sup>64</sup> Lyon et al. also observed emissions from separator pressure relief valves, dehydrators, and flares.

Commenter (2433-EDF et al) notes a more recent study, Rutherford et al., found that tanks are the largest emission source and biggest reason for disagreement between the study results and EPA Greenhouse Gas Inventory (GHGI) data.<sup>65</sup> Rutherford et al. also found that flare methane emissions are underestimated in the GHGI, and that pneumatics and separators are also large sources of emissions.<sup>66</sup> Tyner and Johnson (2021) also recently found that “[m]ore than half of emissions were attributed to three main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%).”<sup>67</sup> Robertson et al. (2020) found that simple sites with less equipment had lower emissions than those with more equipment.<sup>68</sup> And Zavala-Araiza et al. (2015) found that stuck separator dump valves and tank flashing events were causes of super-emitters.<sup>69</sup>

Commenter (2433-EDF et al) states their PermianMAP project has observed many emission events from tanks and flares.<sup>70</sup> Helicopter surveys found 79% of methane plumes were from tanks; and among marginal wells, 17% of complex sites (with multiple pieces of equipment) had emissions, while none were detected at “pump-jack only” sites.<sup>71</sup> Ravikumar et al. (2020)

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<sup>63</sup> Daniel Zavala-Araiza et al., Super-emitters in natural gas infrastructure are caused by abnormal process conditions, 8 *Nature Commc’n* 14012 (2017), <https://www.nature.com/articles/ncomms14012#Sec6> [hereinafter Zavala-Araiza, Super-emitters].

<sup>64</sup> David Lyon et al., Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites, 50 *Env’t. Sci. Tech.* 4877 (2016), <https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705> [hereinafter Lyon et al., Aerial Surveys].

<sup>65</sup> Jeffrey Rutherford et al., Closing the methane gap in US oil and natural gas production emissions inventories, 12 *Nature Commc’n* 4715, at Figure 3 (2021), <https://www.nature.com/articles/s41467-021-25017-4>.

<sup>66</sup> *Id.*

<sup>67</sup> David Tyner & Mathew Johnson, Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data, 55 *Env’t Sci. Tech.* 9773 (2021), <https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572>.

<sup>68</sup> Anna Robertson, et al., New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, 54 *Env’t. Sci. Tech.* 13926 (Oct. 15, 2020), <https://pubs.acs.org/doi/10.1021/acs.est.0c02927>.

<sup>69</sup> Daniel Zavala-Araiza et al., Reconciling divergent estimates of oil and gas methane emissions, 51 *Proc. Nat’l Acad. Sci.* 15597 (2015), <https://www.pnas.org/content/112/51/15597>.

<sup>70</sup> Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%. PermianMAP, Prevalence of Emissions by Equipment Type, (Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%).

<sup>71</sup> *Id.*

similarly found the largest emissions from tanks, concluding that “[t]he outsized role of tanks in contributing to overall methane emissions at natural gas facilities has been a defining feature in many recent studies, and points to a critical need for tank-focused LDAR regulations.”<sup>72</sup>

Commenter’s (2433-EDF et al) review of OOOOa compliance reports further supports EPA’s equipment-based approach.<sup>73</sup> The commenter downloaded over 20,000 compliance reports and isolated 80,121 reported component leaks from instrument-based fugitive emissions surveys. They then categorized each reported leak by component type and by equipment type when possible. The commenter was able to assign an equipment category to 46% of reported component leaks. Table 2 of the commenter’s letter contains information on leaks that could be categorized by equipment type.

Commenter (2433-EDF et al) states EPA’s proposed equipment-based approach aligns with the substantial body of science and data characterizing emissions from certain types of failure-prone equipment, in particular flares, storage tanks, and gas-driven pneumatic controllers.

Commenter (2433-EDF et al) adds another benefit of the tiered equipment-based approach is that it incentivizes operators to eliminate polluting sources from their sites by designing sites with minimal emissions points and electrifying certain equipment types. For example, instead of creating five separate well sites with tanks and other major processing equipment that would all be subject to quarterly OGI, EPA’s proposed structure incentivizes the use of centralized production facilities and wellhead-only well sites. By utilizing this type of design, operators can focus monitoring resources on the centralized production facility.

Commenter (2462-Cynthia Walter) states well-head failure is common even for new wells, resulting in substantial fugitive emissions. For example, Ingraffea et al. reported wells after 2005 had well-head failure rate of about 10% within the first year and rising to 40% likelihood of failure within the first 10 years, based on real world inspections of thousands of wells in Pennsylvania.<sup>74</sup>

Response II-4-26: The EPA agrees that an equipment-based fugitive emissions component monitoring and repair approach is appropriate. This approach has been retained in the final rule. The specific requirements being finalized are described in section X.A.1 of the preamble to the final rule.

Comment: Commenter (2353-CrownQuest Operating, LLC.) states EPA used the referenced study<sup>75</sup> to show that emissions strongly correlate to the amount of equipment on site and no other significant factors. The EPA uses this study to mark all well sites as affected facilities by component counts and potential for fugitive emissions while ignoring the specifics of types of wells, equipment used for unique well types, geological particularities, and geographic location

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<sup>72</sup> Ravikumar 2020, supra note 104 (citing Lyon et al. Aerial Surveys, supra note 132).

<sup>73</sup> For a full description of this analysis and methodology, see Env’t Def. Fund, OOOOa Compliance Report Analysis Methodology, supra note 116.

<sup>74</sup> Ingraffea. 2014. Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012 Proc. National Academy of Sciences 111 (30) 10955-10960. <https://doi.org/10.1073/pnas.1323422111>.

<sup>75</sup> Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells[<https://www.osti.gov/servlets/purl/1865859>].

cannot be considered as the correct application of this study. This study does support the idea that leak frequency is strongly correlated to major component counts present. It is logical to deduct that more equipment on-site results in a higher frequency of leaks. However, this point fails to justify regulation when the purpose is to decrease emissions and not instances of leaks.

Commenter (2353-CrownQuest Operating, LLC.) argues the justification that the EPA should use to support the implementation of NSPS OOOOb/EG OOOOc is a strong correlation between major component count and the emission rates and inspection frequency and a decrease in emissions. This study does not demonstrate either of those two categories but instead says more leaks will occur when more equipment is present. This study states that equipment count has a weak correlation to emission rates while also admitting that emission monitoring frequency does not correlate with the frequency of detected emissions.

Commenter (2353-CrownQuest Operating, LLC.) notes the EPA reference data shows that increasing LDAR surveys might find more leaks but will not decrease the overall emission rates. The study finds that the second strongest correlation in their dataset is the Basin lending significant credence to the point that sweeping federal regulation across all basins would be unnecessary and ineffective. Overall, this study does not address the magnitude of emissions, emissions root cause, or the reduction of emissions. To use this study as the basis for implementing a BSER of more frequent surveying is an incorrect application of the actual conclusions of this study.

Response II-4-27: The EPA does not agree with most of the arguments presented by the commenter. The EPA did not solely use the results of the DOE Study to justify BSER. The BSER analysis presented in the December 2022 Supplemental Proposal was based on data and information from several sources including results from FEAST modeling and a cost analysis of different fugitive emissions monitoring and repair programs. The EPA found that the DOE Study supported the development of various model plants based on equipment and component counts, where the DOE Study indicated a strong correlation between the major equipment count and the frequency of fugitive emissions. As discussed in the December 2022 Supplemental Proposal preamble, EPA noted that it requested comment on other thresholds that could be used to set monitoring requirements for well sites. One option was to include an equipment-based approach, in which well sites with specific leak-prone equipment would have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment) would have a different set of requirements. This was the fugitive emissions monitoring approach the EPA proposed in the December 2022 Supplemental Proposal, which is also the approach for the final rule.

The EPA notes that the information collected in the DOE Study regarding the frequency of routine leak inspections did not include data on the type of inspection conducted. Facilities indicating weekly or monthly inspections were likely using AVO methods, whereas facilities reporting annual or semiannual inspections are more likely to have been referring to OGI inspections. The EPA's FEAST modeling suggests that less frequent OGI inspections achieve similar emission reduction performance as frequent AVO inspections, which could be the reason emission performance was not strongly tied to leak inspection frequency in the DOE Study. The EPA recognizes that leak generation rates and leak size are highly variable. Therefore, the EPA relied on Monte Carlo simulations of the model plants (plants with different number and types of equipment) using FEAST to assess the average performance of different LDAR programs for reducing emissions. The EPA maintains that this is the appropriate method for evaluating the

average performance of different LDAR programs for the BSER determination considering the variability in fugitive emissions.

Comment: Commenter (2353-CrownQuest Operating, LLC.) states the EPA references the report by Omara, *et al.*<sup>76</sup> to support the claim that marginal wells are responsible for approximately half of the well site emissions. However, this study fails to support the EPA's claims for several reasons. First, the study references six other studies that used data collection methods that are not admissible by the EPA's inspection standards. The referenced studies use "Top-Down" data collection methods that fail the OGI and LDAR standards required by EPA Method 21.

Commenter (2353-CrownQuest Operating, LLC.) states the data collected in these studies and their results are not acceptable. Beyond being unacceptable, much of the data is too old to be accurate. Several studies happened before the implementation of NSPS OOOOa regulation and did not account for the industry's decrease in emissions over the past decade. Finally, the study collects data from only a few basins and does not represent the entire US's oil and gas production. Overall, the data drawn for this study is not comprehensive and is inadequate to support regulation. The production data referenced (from Enverus) is generic and not site-specific. Each emissions study referenced does not meet the EPA's requirements for LDAR inspections. Many of these referenced studies are older than the EPA OOOOa regulation. If the EPA wants to justify action, it is perplexing that the EPA refuses to reference or use its data from OOOOa, which contains over 10 years' worth of legally submitted OGI surveying results.

Commenter (2353-CrownQuest Operating, LLC.) argues this data is the best available data and science on emission reductions. The EPA should use the supplemental data voluntarily submitted to and aggregated by The Environment Partnership, which with the willing participation of more than 70% of onshore oil and gas production and midstream companies, has performed more than 345 million legal and EPA-acceptable LDAR inspections on sites in almost all basins across the US. The EPA should not cherry-pick studies that use cherry-picked data with inadequate methods by their standards to justify nationwide new regulations.

Commenter (2353-CrownQuest Operating, LLC.) adds the EPA claims they do not have any accurate analysis of component-specific emissions and that natural gas-actuated controllers, controlled storage vessels, and controllers are "known to be sources of large emissions events." This conclusion is contradictory and has no significant data to be the basis for classifying specific components as "known sources of large-scale emissions." Ultimately, the study's conclusions take a step towards categorizing wells based on age and production. However, their conclusions contradict this study (<https://www.osti.gov/servlets/purl/1865859>) referenced elsewhere in the preamble. It concludes the frequency of detected emissions and magnitude of emission rates are "weakly correlated" to total production.

Response II-4-28: As part of response to comments on the November 2021 proposal requesting that production volumes be a factor in establishing different fugitive emissions monitoring requirements for different well sites, the EPA referenced the report by Omara, *et al.*<sup>77</sup> in the December 2022 Supplemental Proposal in conjunction with other reports (including the DOE Study) to support why EPA could not draw a conclusion that production levels should provide

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<sup>76</sup> <https://www.nature.com/articles/s41467-022-29709-3>.

<sup>77</sup> <https://www.nature.com/articles/s41467-022-29709-3>.

the basis for consideration of different fugitive emissions requirements for well sites, but that there are significant emissions from well sites producing less than 15 boe/day and that distinguishing among well sites based on equipment and component counts would be appropriate. The EPA did not directly use the data collected in the six studies mentioned in the Omara, *et al.*<sup>78</sup> report. Furthermore, EPA acknowledged in the preamble to the December 2022 Supplemental Proposal that the study was not limited to fugitive emissions, but included, conclusions from this study cannot be directly applied to the specific fugitive sources covered by this action.

Comment: Commenters (2392-Earthjustice et al., 2433-EDF et al.) ask EPA to specifically consider regulating sites that have separators, which are known to be a source of large emissions.

Commenter (2392-Earthjustice et al.) argues EPA should strengthen the LDAR requirements by adding separators to the list of failure-prone equipment such that any site with a separator is subject to quarterly OGI.

Commenter (2433-EDF et al.) believes that EPA should add any sites with a separator to the definition of fugitive emissions component, thereby excluding a single separator from the list of permissible equipment at small well sites. Separators are a known source of large fugitive emission events.

Commenter (2433-EDF et al.) notes EPA clearly explains why fugitive emissions from wellheads and tanks can be detected and remedied without an OGI survey. However, this justification is not provided for separators, even though numerous studies find that separator malfunctions are a source of large emissions events.<sup>79</sup> In the DOE marginal well study, three of the ten largest measured emissions events stemmed from separator dump valves.<sup>80</sup> This study identified separators with ages as high as 72 years in their survey of field sites and found that 26% of separators at light oil sites and 67% of separators at gas sites had detectable emissions using OGI.<sup>81</sup> Separators are well-documented as a source of frequent and often large emissions events, and they are also a source of smaller emissions that may not be detectable through AVO.<sup>82</sup>

Commenter (2433-EDF et al.) states separators are a very prevalent piece of failure-prone equipment at smaller well sites. The commenter used 2016 Information Collection Request (ICR) data to analyze single well sites with a single piece of major processing or production equipment. Our analysis found that 11% of the well sites reported to the ICR would meet EPA's proposed definition of a small well site. Of those sites, 77% had a single separator present. EPA's proposed definition of small well sites therefore likely exempts many single well sites

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<sup>78</sup> <https://www.nature.com/articles/s41467-022-29709-3>.

<sup>79</sup> Rutherford et al., *supra* note 133 (Figure 3 shows separators as large source of emissions within the equipment leak category.); Zavala-Araiza, Super-emitters, *supra* note 131 (In the second paragraph of their discussion, they cite stuck separator dump valves, design failures like vortexing or gas entrainment during separator liquid dumps, and equipment or process issues such as over-pressured separators as some of the many abnormal process conditions observed in field campaigns.).

<sup>80</sup> Richard L. Bowers, Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells Report at 19 (2022), <https://www.osti.gov/biblio/1865859>. [hereinafter "Bowers Report"].

<sup>81</sup> Richard L. Bowers, Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells. at Slide 21 (Aug. 2021), [https://netl.doe.gov/sites/default/files/netl-file/21CMOG\\_OG\\_Bowers.pdf](https://netl.doe.gov/sites/default/files/netl-file/21CMOG_OG_Bowers.pdf).

<sup>82</sup> Zavala-Araiza, Super-emitters, *supra* note 131; Lyon et al., Aerial Surveys, *supra* note 132.

with separators from regular OGI inspections. This is concerning given the prevalence of large emissions events originating from separators.

Commenter (2433-EDF et al) states EPA notes in modeling the rule's impacts that small well sites were not treated differently than single wellhead-only sites on the assumption that these sources would have comparable emissions. However, because separators will be present at the majority of sites falling into EPA's proposed small well site category, the commenter does not believe that assumption is correct. Based on their review of EPA's model plants, they believe that the emissions profile of a single wellhead site with a separator is much closer to the well site model plant and the multiple wellhead only model plant than the single wellhead only model plant.

Using Rutherford 2021 emission factors, commenter (2433-EDF et al) estimates the emissions from small sites with separators to be 3.94 tpy per gas site and 1.13 tpy per oil site. Applying the direct ICR equipment proportions (77% of small sites have a separator, 2% have a reciprocating compressor, 1% have a dehydrator, 19% have a tank) yields average Rutherford emissions of 3.71 tpy and 1.04 tpy for gas and oil wells, respectively. Even when averaged with the lower DOE study emission factors, the average baseline emissions from small sites is much closer to the 0.5% leak generation rate baseline emissions of multi-wellhead only sites. The commenter believes that when equipment types at small sites are accurately represented, these sites more closely represent the multiple wellhead only or well site model plants.

Commenter (2433-EDF et al) argues OGI surveys are effective at detecting emissions from separators. Their analysis of upstream OGI surveys in OOOOa compliance reports finds that reported leaks from separators are common and only eclipsed in frequency by tanks, pneumatic devices, and flares.<sup>83</sup> However, the commenter does not have data to indicate that AVO surveys can effectively detect emissions from this component. Continuing to include sites with separators in the small well site category will likely lead to significant fugitive emissions and super-emitters that could otherwise be detected and repaired with OGI. EPA should therefore remove a single separator from the list of major production and processing equipment that can be present at a small well site and ensure any site with a separator is subject to quarterly OGI. The commenter estimates that doing so will increase the emissions coverage of OGI to over 80% of total emissions, thereby ensuring greater overall reductions.

Response II-4-29: The EPA acknowledges the commenters' concerns regarding regulating sources to be known to be sources of large emissions, including separators. As discussed in the December 2022 Supplemental Proposal preamble, EPA noted that it requested comment on other thresholds that could be used to set monitoring requirements for well sites, one option which was to include an equipment-based approach, in which well sites with specific leak-prone equipment would have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment) would have a different set of requirements. This was the fugitive emissions monitoring approach the EPA proposed under the December 2022 Supplemental Proposal and this approach is being finalized.

To ensure that large emissions from well sites and centralized production facilities with separators do not go undetected, the EPA is specifying that owners and operators of well sites

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<sup>83</sup> See Table 6, *infra*, (finding 699 separator leaks).

and centralized production facilities that have separators conduct a visual inspection of all separator dump valves to ensure the dump valve is free of debris and not stuck in an open position must be conducted in conjunction with the monitoring survey. The owner or operator must repair any dump valve not operating as designed. This requirement would specifically apply fugitive emissions components affected facilities at small well sites, and well sites or centralized production facilities with major production and processing equipment.

In addition to including the specific requirement to inspect the separator dump valve in conjunction with the monitoring survey, the EPA is also clarifying in the fugitive emissions component definition that “valves” include separator dump valves in order to eliminate any ambiguity as to whether separator dump valves are considered fugitive emissions components. The EPA is finalizing a definition of fugitive emissions components that specifically includes separator dump valves, thus clarifying that the separator dump valve is subject to monitoring by OGI, AVO, or other detection methods. In addition, because emissions from malfunctioning separator dump valves are a known source of large emissions (as the commenter noted) and because sometimes there is visual evidence of the malfunction, the EPA is requiring in the final rule that during the regular AVO monitoring surveys (either quarterly or bimonthly depending on the site), a visual inspection must be conducted of all separator dump valves to ensure that they are free of debris and not stuck in an open position, and any dump valve not operating as designed must be repaired.

#### 4.1.3.4 Single Wellhead Only/Small Well Sites

Comment: Commenters (2039-Citizens to Preserve Ligonier Valley, Inc., 2179-KIOGA, 2200-NuEnergy Operating Inc., 2205-Kriebel Well Services, Inc., 2223-Texas Alliance of Energy Producers, 2238-SOOGA, 2294-Ohio Oil and Gas Association, 2428-API, 2433-EDF et al, 2439-State of Michigan Department of Environment, Great Lakes and Energy) support the ability to use AVO at single wellhead only well sites.

Commenter (2428-API) states an AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727).<sup>84</sup> Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods.

Commenter (2428-API) argues given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled

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<sup>84</sup> On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.



with proposed requirements<sup>85</sup> for conversion to nonemitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

Commenter (2433-EDF et al) notes EPA estimates that approximately 95,000 well sites nationwide, or approximately 12 percent of the total nationwide well site count, would meet the definition of "small well site."<sup>86</sup> EPA's analysis also estimates that roughly 50% of total well sites nationwide would be classified as either single wellhead-only well sites or small well sites. Based on the commenter's analysis, 408,700 well sites are responsible for 24% of fugitive emissions. Therefore, small well sites should be subject only to quarterly AVO inspections.<sup>87</sup>

Commenter (2433-EDF et al) urges EPA to consider instrument-based inspections or a single initial OGI inspection at smaller and marginal sites to further drive down emissions. At minimum, EPA should provide an alternative semiannual OGI compliance option for any site subject to the proposed quarterly AVO only requirements. While the commenter supports the proposed AVO requirements, AVO cannot detect emissions as effectively as OGI, especially emissions from certain equipment types. The commenter recommends the site be required to reclassify and conduct quarterly OGI (or the equivalent alternative).

Commenter (2433-EDF et al) notes that while stakeholders have raised concerns about compliance burdens associated with monitoring at smaller wells, 92% of marginal wells are owned by large companies with average revenues of over \$100 million per year.<sup>88</sup>

Response II-4-30: The EPA agrees AVO inspections for fugitive emissions monitoring for single wellhead only well sites and small well sites are appropriate. This approach has been retained in the final rule. The specific requirements being finalized for single wellhead only well sites and small well sites are described in section X.A.1.a.ii of the preamble to the final rule for new sources under NSPS OOOOb and in section X.A.1.b.ii of the preamble to the final rule for existing sources under EG OOOOc.

Comment: Commenters (2185-New York State Common Retirement Fund (CRF), 2333-LongPath Technologies, Inc. (LongPath), 2408-Colorado Local Government Coalition, 2436-Louis Pochet, 2462-Cynthia Walter) have concerns with the proposed AVO-only requirements

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<sup>85</sup> See Comment 7.0.

<sup>86</sup> Data from the 2016 ICR.

<sup>87</sup> Env't Def. Fund., Methodology for Estimating Emissions Covered by AVO-Only Standards (Attachment G).

<sup>88</sup> Env't Def. Fund, Updated Marginal Well Operatorship Analysis (included as Attachment H). Our updated analysis uses improved Enverus from 2022. This impacted EDF analysis of well operatorship based on Enverus 2019 production data; however, the overarching conclusion remains the same. With respect to coverage, the number of well sites with non-zero oil and gas production in 2019 increased from ~704k to ~745k and the corresponding number of operators increased from ~12k to ~13k. The percentage of marginal wells owned by large operators remains the same at 92%. Total 2019 gross revenue generated by large operators decreased slightly but remains above \$300B (\$303B down from \$329B). The average 2019 gross revenue per operator decreases slightly but remains above \$100M (\$111M down from \$128M).

for small well sites and single wellhead only sites. Small well sites can have leaks<sup>89</sup> and AVO is not an effective method for identifying leaks.

Commenter (2185-CRF) urges EPA to consider concerns with the sole use of AVO techniques raised by the Interstate Technology and Regulatory Council (ITCR) in its 2018, Evaluation of Innovative Methane Technologies, Methane-1.<sup>90</sup> As noted by ITCR, the use of this technique relies on the use of an individual person's senses, which are subject to individual variation. It is important to note that these senses may be impaired in individuals either by age or by regular exposure to the loud noises and strong odors that may be found on oil and gas production sites. The commenter states the EPA should consider requiring the use of additional technologies, such as handheld natural gas detectors, to back up the use of AVO monitoring to ensure that leaks are accurately detected at this class of sites.

Commenters (2333-LongPath, 2348-Energy Workforce and Technology Council) state AVO inspection may detect leaks after the event, but AVO inspection does not identify potential failures caused, *e.g.*, by seal failures or loosening of threaded/flange connections. This is an inherent flaw in the AVO inspection methodology, *i.e.*, it is not predictive, and it only catches emissions happening at the moment of inspection. Continuous monitoring, on the other hand, allows an inspector to monitor over time.

Commenter (2408-Colorado Local Government Coalition) recommends that EPA require annual OGI for single wellhead only and small well sites, based on rules adopted by Colorado and New Mexico. While the commenter does appreciate the proposed AVO inspections, OGI methods can detect leaks that a human may not be able to detect. AVO inspections, in contrast to OGI inspections, rely on a person's senses of smell, hearing and sight to achieve maximum emissions reductions. Such senses may not be as reliable as instruments. Moreover, EPA may require operators retain video footage demonstrating that OGI inspections in fact occurred and documenting the results of those inspections. The same is not true for AVO inspections. Absent a way to document reliably that an operator, or more likely a contractor, conducted a thorough AVO inspection, the commenter fears this requirement will be abused and will not lead to the emissions reductions EPA expects.

Commenter (2408-Colorado Local Government Coalition) goes further, Colorado and New Mexico require instrument-based inspections for small wells, and New Mexico requires instrument-based inspections for wellhead only facilities. Colorado requires all well production facilities that commence operation on or after May 1, 2022, to conduct monthly instrument-based inspections, regardless of size or emissions potential.<sup>91</sup> The only exceptions to this is for facilities which are not home to leak-prone equipment (*i.e.*, facilities without storage tanks, natural gas-fired reciprocating internal combustion engines and gas-powered pneumatic devices)<sup>92</sup> or those that contain robust monitoring for leak prone equipment (*i.e.*, those that install an automatic pressure management and pilot light system on controlled storage tanks).<sup>93</sup> Such facilities must

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<sup>89</sup> LGC Comments, EPA's Proposal to Reduce Greenhouse Gasses and other Pollutants from the Crude Oil and Natural Gas Source Category under the Clean Air Act, p. 10-15 (Jan. 31, 2022).

<sup>90</sup> Interstate Technology and Regulatory Council, Evaluation of Innovative Methane Technologies, Methane-1, Washington, D.C. 2018. Available at: <https://methane-1.itrcweb.org/>.

<sup>91</sup> 5 Colo. Code Regs. § 1001-9-D-II.E.4.e.(ii).

<sup>92</sup> 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(i).

<sup>93</sup> 5 Colo. Code Regs. § 1001-9-D-II.E.4.f.(ii).

conduct instrument-inspections semi-annually or annually, depending on emissions potential.<sup>94</sup> Well production facilities that commenced operation before May 1, 2022 must conduct at least annual instrument-based inspections.<sup>95</sup> New Mexico requires at least annual OGI inspections of **all** well sites, including wellhead only well sites.<sup>96</sup> New Mexico's proposal has the support of the local community and national environmental groups.<sup>97</sup>

Commenter (2436-Louis Pochet) adds AVO inspections are – by themselves - helpful but not fully reliable. Fugitive emissions could easily be invisible, have no smell, and the sounds can be masked by other equipment or local noise. In-person inspections of sites are extremely important, however, to make sure monitoring equipment is in the correct place and to document that equipment is working or idle, and conditions are normal. Researchers could be contracted to compare air pollutants upwind and downwind from the compressor stations, wells and mercaptan addition locations.

Response II-4-31: While we agree that the performance of AVO is more variable and dependent on the sensitivity and thoroughness of the inspector; however, we found that it is not cost-effective to require instrument monitoring for the well-head only sites, even at an annual frequency. While our assessment of instrument monitoring specifically considered OGI, we expect that it is indicative of the costs of any monitoring inspection that can achieve comparable emission reductions to OGI. We specifically considered instrument monitoring first because we expect less variability in the performance of instrument monitoring. However, after determining the cost-effective OGI monitoring frequency, we evaluated the ability of using AVO inspections to achieve additional emission reductions. For the wellhead only sites, this assessment determined that annual instrument monitoring was not cost effective, but that AVO inspections would produce cost-effective emission reductions and determined to be BSER. We are finalizing the requirements for small well sites as proposed.

Comment: Commenters (2304-PIOGA), 2713-Northeast Natural Energy LLC) state a "well site" consists of a well head, tank, meter, and perhaps a separator, all confined within perhaps a 25 foot diameter. EPA's characterization of this as "major production and processing equipment" is just nonsensical. It would almost be laughable, except that the adverse economic consequences to the family-run, "small business" as defined by the Regulatory Flexibility Act is anything but funny. These businesses are their livelihoods. EPA has abandoned terminology accepted by the industry – and regulators – that often characterized these truly small well sites as "marginal wells." That terminology aptly describes the economic reality of these wells - their existence is marginal. Unnecessary costly quarterly OGI requirements will make many of these wells uneconomical to operate. Commenter (2304-PIOGA) and the families and local economies that depend on the continued operation and existence of these low production wells ask that EPA sharpen its pencil and find a more fair and workable solution.

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<sup>94</sup> 5 Colo. Code Regs. §1001-9-D-II.E.4.f.

<sup>95</sup> 5 Colo. Code Regs. §1001-9-D-II.E.4, Table 5.

<sup>96</sup> N.M. Code R. §20.2.50.116.

<sup>97</sup> Community and Environmental Parties Joint Proposed Statement of Reasons, New Mexico Environmental Improvement Board rulemaking in the Matter of Proposed New Regulation, 20.2.50 NMAC, Oil and Gas Sector, Ozone Precursor Pollutants (Jan. 20, 2022), available at <https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/2022-01-20-EIB-No.-21-27-Comty.-and-Env.-Parties-Proposed-Statement-of-Reasons-pj.pdf>.

Commenter (2713-Northeast Natural Energy LLC) states the monitoring/screening requirements for small well sites seem reasonable until one examines the definition of a small wellsite. A small wellsite is defined as single wellhead well sites that do not contain any controlled storage vessels, control devices, pneumatic controller affected facilities, or pneumatic pump affected facilities, and include only one other piece of major production and processing equipment. Major production and processing equipment that would be allowed at a small well site would include a single separator, glycol dehydrator, centrifugal and reciprocating compressor, heater/treater, and storage vessel that is not controlled. The forgoing does not consider the production rate at the site, therefore a marginally producing gas or oil well located on a site with a single separator and a single water storage tank would no longer be considered a small well site and would be required to follow the same screening frequency and screening methods as a large multi-well unconventional site producing 100 mmcf per day and includes multiple gas processing units, possibly a glycol dehydrator unit and several storage tanks, as well as other "major production and processing equipment". EPA should consider using a production threshold regardless of the equipment count or type methodology.

Response II-4-32: The EPA disagrees with the commenter. Fugitive emissions are not a function of production or throughput, but the number of fugitive emission components in service at the site and the types of major equipment at the site. Therefore, if a marginal wellsite has several major production or processing equipment, the EPA determined that OGI monitoring is cost-effective and therefore BSER.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2238-Ohio Oil and Gas Association, 2294-SOOGA, 2304-PIOGA, 2403-PAO) urge EPA to create a fifth (intermediate) source category via the expansion of the components in the "small well site" facility, to ensure that higher producing, albeit still "low production", wells are not regulated as a "large well site." This includes increasing the count of major production equipment from one to two, to further differentiate the requirements applicable to the lowest of the low production wells. Limiting a "small well site" to only one of those pieces of equipment inherently – albeit inaccurately – disqualifies true small well sites from the "small well site" classification. AVO inspections should apply to this "intermediate" source category.

Response II-4-33: The EPA disagrees with the commenter. Fugitive emissions are not a function of production or throughput, but the number of fugitive emission components in service at the site. The commenter appears to suggest that "large well sites" would have lower emissions if they have lower throughput, but that is not the case. The EPA maintains that sites with two or more major production or processing equipment must conduct quarterly OGI (or the equivalent advanced technology monitoring).

Also, the EPA developed well site model plants for the December 2022 Supplemental Proposal that were believed to be representative of common well site configurations. The well site model plants developed were not expected to represent every possible well site setup, but the distinct model plants that were developed were designed to account for various equipment types located at sites ranging from single wellhead only well sites and small well sites to complex sites with various major production and processing equipment known to be sources of large emissions.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2279-U.S. Small Business Administration, 2304-PIOGA, 2205-Kriebel Well Services, Inc.) believe EPA underestimates how often well and

production sites are visited by the operator's personnel, dramatically reducing the potential for any leak that would develop and go unnoticed for any length of time. Production equipment present at these types of locations, whether compressors, separators, or dehydrators, are very important for continuous operation and require frequent visits. The two pieces of equipment used or occasionally used at well or production sites with the greatest potential to have fugitive emissions are heavily used valves that may develop small stem leaks and pressure relief valves that could very rarely malfunction and stick partially open after being actuated. In both cases, this type of equipment is located at sites that are regularly visited and would be quickly identified and corrected. EPA's eliminating the requirement of OGI for fugitive emission surveys at wells and small production sites to identify methane leaks is more than compensated by the frequency with which the small operator's personnel visit the sites potentially identifying any leaks that might develop.

Commenter (2172-KOGA) notes most single wellhead gas well sites still use orifice meters to measure gas flow utilizing paper charts, the wells are visited by a pumper on at least a monthly basis. Most oil wells are visited daily. The commenter believes that limiting fugitive methane emissions from legacy producing properties typical of small operators is best accomplished for the small operator by utilizing existing personnel who know what a leak is and how to repair it and educating them as to the urgency of repairing and reporting leaks found.

Response II-4-34: The EPA acknowledges the commenters' remarks. As proposed, the rule finalizes quarterly AVO inspections for single wellhead only well sites and small well sites.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2198-University of Denver College, 2351-Jonah Energy LLC, 2433-EDF et al) agree small well sites should be subject only to quarterly AVO inspections.<sup>98</sup> Commenter (2198-University of Denver College) feel quarterly monitoring of these new or modified sites under NSPS, for the entire life of the site, is a needed addition to the proposal. This will provide information on fugitive emissions and emissions from covers and CVS.

Response II-4-35: The EPA acknowledges supportive comments. As proposed, the EPA is finalizing quarterly AVO inspections for single wellhead only well sites and small well sites.

Comment: Commenter (2304-PIOGA) believes EPA needs to create an "Intermediate Well Site" category based on a combination of throughput and component count, and the associated monitoring should be more heavily based on AVO surveys, with perhaps an initial OGI survey, which is phased out or not at all necessary if no leaks are detected. The reality is that EPA's proposed definition of a small well site fails to understand typical conventional/vertical wells sites in Pennsylvania and much of Appalachia.

Commenter (2304-PIOGA) states most conventional wells in this region involve one well (occasionally two), one or two brine tanks, a separator, and/or possibly one controller. Nonetheless, these sites typically will have two pieces of equipment that EPA has deemed "major production and processing equipment." Most of these single well, or even two well, sites provide 1-3 barrel of oil equivalent (BOE) per day – if that. Sites producing more than 8 BOE a day are the exception. For example, one family run company with approximately 50 employees

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<sup>98</sup> Env't Def. Fund., Methodology for Estimating Emissions Covered by AVO-Only Standards (Attachment G).

owns/operates approximately 1,900 low (very low) production wells. Approximately 90% of their wells would fall into the "large category" because they have more than one piece of "major production and processing equipment."<sup>99</sup> This is also a problem for conventional "centralized production facilities" as well. One of the commenter's members reported they operated approximately 21 "centralized productions facilities" that typically have 20 or more wells "feeding" the production facility, and yet all of them are under EPA's previous exemption threshold of 15 BOE a day. The previous low production well exemption was a reasonable compromise and would have allowed most low production wells to operate – but perhaps that was why EPA shifted away from the production-based exemption.

Commenter (2304-PIOGA) adds the Department of Energy (DOE) study on emissions from low production/marginal wells demonstrated that lowering the throughput from 15 BOE to 8 or perhaps even slightly lower would have had minimal adverse impact on emission reductions but would have allowed hundreds of thousands of existing low production/marginal wells to continue to operate. Again – perhaps that is why EPA shifted away from basing requirements on throughput. Regardless, the commenter has proposed yet another compromise that is more realistic utilizing both "component count" and throughput.

Response II-4-36: The EPA disagrees with the commenter. Fugitive emissions are not a function of production or throughput, but the number of fugitive emission components in service at the site. The commenter appears to suggest that "large well sites" would have lower emissions if they have lower throughput, but that is not the case. The EPA maintains that sites with two or more major production or processing equipment must conduct quarterly OGI (or the equivalent advanced technology monitoring).

The EPA developed well site model plants for the December 2022 Supplemental Proposal that were believed to be representative of common well site configurations. The well site model plants developed were not expected to represent every possible well site setup, but the distinct model plants that were developed were designed to account for various equipment types located at sites ranging from single wellhead only well sites and small well sites to complex sites with various major production and processing equipment known to be sources of large emissions.

Comment: Commenters (2205-Kriebel Well Services, Inc., 2304-PIOGA, 2359-Kevin D. Dayaratna, Heritage Foundation) state EPA's pollution is the commenter's product – there can be no more pure economic incentive to capture and not waste every molecule of methane. EPA paints a picture with its discussion of "super-emitters" as if the owner/operators of low production wells are scofflaws that do not care if something breaks and there are uncontrolled emissions to the environment. Nothing could be further from the truth. The owners/operators of wells visit well sites frequently – and the more productive the well, the more frequently they visit. One small business in Pennsylvania reported over 70% of their wells are visited weekly, if not daily. Again, all of these wells are still below the low production well exemption threshold, but the more productive wells are visited multiple times a week. Even the least productive wells are typically visited at least monthly. Owners/operators are looking for signs of leaks – whether

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<sup>99</sup> This is not an isolated example. An operator with a similar number of wells reported over 80% of their wells would trigger the quarterly OGI requirements despite an average gas production of 5 mcf/d and oil production of 0.6 BOE/d. Another family owned business reported that, of their approximate 550 wells, approximately 98% are low production wells with an average production of 4 mcf/d – anything less than 90 mcf/d or 15 BOE/d is considered a low production or marginal or stripper well.

smelling gas, hearing gas or seeing signs that a connection is leaking (discolored vegetation), and to the greatest extent possible, they fix leaks on-site and confirm they are fixed – often with simple soap and bubbles – an OGI camera is not needed. To the extent the issues cannot be addressed onsite when leaks or malfunctions are identified, owners/operators will normally close-in or make process changes to minimize or eliminate the leaks – they are protecting the environment and their product.

Response II-4-37: The EPA acknowledges the commenters’ remarks. As proposed, the rule finalizes quarterly AVO inspections for single wellhead only well sites and small well sites.

Comment: Commenter (2166-Ohio Department of Natural Resources (ODNR)) states additional factors need to be considered when requiring a surface casing valve to be closed. Since 2012, Ohio has required that the valve on the surface production casing annulus or surface-intermediate casing annuli be accessible and equipped with a pressure gauge to allow continual monitoring of mechanical integrity. The valve is also required to be equipped with a properly functioning pressure relief valve to be set in a manner that prevents annular over pressurization for safety. Simply closing a surface casing valve without proper monitoring and safety considerations can endanger public health and safety. Ohio is currently proposing strengthening annular monitoring for all wells and revising rules to require horizontal wells to route pressure relieve systems into their vapor recovery system.

Response II-4-38: The EPA acknowledges the commenter’s remarks regarding surface casing valves. As discussed in the December 2022 Supplemental Proposal, AVO can easily be used to identify whether the surface casing valve is open or closed during an inspection and would not require the use of OGI to detect the leak.

EPA acknowledges that on certain pieces of equipment pressure relief devices need to be used for safety reasons. However, safety relief devices should not be continuously left in the open position, and it is important to check that these devices are in the closed position when there is no safety concern, as pressure relief devices will release fugitive emissions when open. These devices are a large source of emissions when they are continuously left in the open position. In a properly designed system, there should be no need to have a continuously open pressure relieve device.

#### 4.1.3.5 Multi-Wellhead Only Well Sites

Comment: Commenter (2433-EDF et al) supports EPA’s proposal to require semiannual OGI monitoring at wellhead-only sites with more than one wellhead. Numerous studies have found emissions from wellheads and the risk of greater emissions and larger leaks increases with the number of wellheads.<sup>100</sup> As determined by EPA, semiannual OGI monitoring is cost-effective at multiple wellhead-only well sites.<sup>101</sup>

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<sup>100</sup> Deighton et al., *supra* note 123 (measuring wellhead emissions and finding that “[s]ome wells were emitting all or more of the reported gas produced at each well, or venting gas from wells with no reported gas production”); Stuart Riddick et al., Measuring methane emissions from abandoned and active oil and gas wells in West Virginia, 651 *Sci. of the Total Env.* 1849 (2019), <https://doi.org/10.1016/j.scitotenv.2018.10.082> (measuring wellhead emissions and finding a “mean of 8.8% of production lost (leaked) at the wellhead.”).

<sup>101</sup> See Revised OGI Cost Effectiveness Tables Folder (included as Attachment F).

If EPA does not adopt the commenter's recommendation to require quarterly OGI at single wellhead sites with separators, the commenter (2433-EDF et al) urges EPA to require semiannual OGI at those sites. The commenter believes ongoing OGI is important for detecting emissions from separators. Their analysis of EPA's model plants also shows that single wellhead sites with separators have an emissions profile that is more similar to well sites and multiple wellhead only sites than to wellhead only sites. The commenter believes this justifies similar treatment and supports ongoing OGI inspection requirements.

Response II-4-39: The EPA acknowledges the supportive comments. As proposed, the EPA is finalizing semiannual OGI with quarterly AVO inspections for multi-wellhead only well sites.

Comment: Commenters (2202-TXOGA, 2326-AXPC, 2428-API, 2446-IPAA) argue that EPA should only require quarterly AVO inspections for multi-wellhead well sites.

Commenter (2202-TXOGA) supports only AVO for wellhead only well sites and not OGI, due to its cost and because the incremental benefit of using OGI on top of AVO would not meaningfully reduce emissions, even using the rationale in the proposal.

Commenters (2202-TXOGA, 2428-API) argue that wellhead only sites make up a very small proportion of methane emissions. Indeed, a study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience emissions two orders of magnitude smaller than complex sites.<sup>102</sup> Another study that addressed over 5000 pieces of equipment at over 1400 facilities across 250 square miles showed that only 2 percent of detected emissions were from wells, and in terms of incidence, similarly, only 5 percent of total detections were from wells.<sup>103</sup>

Commenter (2202-TXOGA) states EPA suggests that it received comments that the emissions from these sources can be large, but clearly such emissions events are not common; otherwise, wellhead only sites would comprise a larger share of methane emissions from the Crude Oil and Natural Gas Source Category. EPA then concludes that OGI is reasonable at multi-wellhead only sites because of the increased number of pipes, connections, valves, and other potential leak sources when there is more than one wellhead.<sup>104</sup>

Commenters (2202-TXOGA, 2428-API) argue BSER factors do not support a conclusion that OGI is reasonably applied to multi-wellhead only sites. As we understand the rationale, EPA would conclude that more resource-intensive OGI surveys are warranted to chase small leaks from multi-wellhead only sites, which comprise a small subset of an already small share of sector methane emissions. In support of the decision to remove the exemption for wellhead only sites, EPA explains that AVO is appropriate for detecting large emissions for single wellhead only sites in the context where there is a lack of ambient noise.<sup>105</sup> Commenter (2202-TXOGA) agrees with this conclusion, and this logic applies equally to multi-wellhead only sites. The commenter

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<sup>102</sup> See 87 Fed. Reg. at 74,729.

<sup>103</sup> Methane Collaboratory, Permian Basin Survey: An Array of Aerial Surveys in the Permian Basin to Acquire the Baseline Distribution of Methane Emission Rates and Sources, available at [https://methanecollaboratory.com/wpcontent/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021\\_vFinal.pdf](https://methanecollaboratory.com/wpcontent/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf).

<sup>104</sup> 87 Fed. Reg. at 74,732.

<sup>105</sup> See id. at 74,727.



urges EPA to remain focused on detecting large emissions from multi-wellhead only sites as well and only require AVO at these sites. Multi-wellhead only sites share key features with single wellhead only sites that make AVO effective, in particular the lack of ambient noise.

Commenters (2202-TXOGA, 2428-API) continue, given that AVO is effective and does not require the specialized equipment and training of OGI, imposing OGI on top of AVO should not be determined to constitute BSER. This is particularly so given the tens of thousands of wellhead-only well sites across the United States, from which methane emissions comprise only a small fraction of overall methane emissions.<sup>106</sup>

Commenter (2326-AXPC) believes quarterly AVO inspection of wellhead only sites would be an effective and economic means to monitor for leaks at wellhead only sites.

Commenter (2326-AXPC) indicates that wellhead only sites generally have fewer fugitive emissions components, and wellheads are constructed with thicker, higher pressure-rated iron causing flanges to be larger such that AVO inspections are able to reliably detect any leaks that may occur. In addition, quarterly AVO requirements would allow operators to train field personnel who are already familiar with sites to conduct AVO inspections during their routine rounds.

Commenter (2428-API) states more frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While the commenter believes quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

Commenter (2428-API) notes EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions.<sup>107</sup> While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

Commenter (2446-IPAA) notes that since the output from the FEAST analyses becomes the baseline for EPA's assessment of emissions reductions from various control strategies and the

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<sup>106</sup> Methane Collaboratory, Permian Basin Survey: An Array of Aerial Surveys in the Permian Basin to Acquire the Baseline Distribution of Methane Emission Rates and Sources, available at [https://methanecollaboratory.com/wpcontent/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021\\_vFinal.pdf](https://methanecollaboratory.com/wpcontent/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf).

<sup>107</sup> Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

basis for the calculations of cost effectiveness, these differences that are two to six times the DOE Study values can produce significant changes in some of the determinations. The commenter states models assuming an average DOE Study methane emissions value of 0.82 tpy and VOC emissions value of 0.23 tpy make different conclusions evident. Based on using more accurate assessments of the emissions from multiple well sites, EPA's proposed approach fails to pass the cost-effectiveness threshold test of \$2,165/ton of methane and the \$5,540/ton of VOC. Consequently, the commenter recommends that EPA use a quarterly AVO program only for its multi-wellhead well sites category like it proposes for the single well sites.

Commenter (2446-IPAA) believes that EPA should have developed its regulatory strategy by first applying an AVO control approach and determining its cost effectiveness. Next, EPA should assess the impact of adding an OGI component, like the semiannual proposal or perhaps an annual proposal. EPA should then evaluate the incremental costs per ton of these additions to determine whether such requirements were cost effective. In other words, the baseline for control would be a periodic AVO requirement and any OGI would be judged on its incremental costs and benefits. This does not appear to be the approach EPA used. EPA appears to have used an OGI baseline and then substituted AVO for quarterly OGI to generate its OGI-AVO combination of requirements.

Response II-4-40: The EPA disagrees that only quarterly AVO inspections should be required for fugitive emissions monitoring for multi-wellhead only well sites. The EPA specifically disagrees that BSER factors are not supportive of EPA's proposal for multi-wellhead only well sites. As discussed in detail in the December 2022 Supplemental Proposal, EPA evaluated the cost-effectiveness of various frequencies of OGI monitoring alone, as well as in combination with different AVO monitoring frequencies.<sup>108</sup> The EPA determined that semiannual OGI monitoring is cost-effective by itself, and in combination with quarterly AVO inspection.

As also discussed in the December 2022 Supplemental Proposal, multi-wellhead only well sites feature both large emission sources that can be identified with AVO as well as additional, generally smaller sources of emissions that are more challenging to identify using AVO. In order to capture both large and small emissions from multi-wellhead only well sites, the EPA proposed semiannual OGI monitoring and quarterly AVO surveys for NSPS OOOOb and EG OOOOc.

The commenters do not appear to be challenging EPA's cost analysis for multi-wellhead only well sites, and in response to comments that EPA should have assessed AVO first, the EPA disagrees (see discussion in section XI.A.1.c of the preamble to the final rule). The EPA is therefore finalizing semiannual OGI with quarterly AVO inspections for multi-wellhead only well sites, as proposed.

Comment: Commenter (2351-Jonah Energy) asks that EPA consider annual LDAR inspections of multi-wellhead only well sites rather than semiannual LDAR inspections in addition to quarterly AVO inspections of all wellheads. The commenter makes the following arguments:

- Semiannual LDAR inspections at multi-wellhead only well sites will divert the commenter's LDAR team from conducting more frequent LDAR inspections at larger centralized production facilities that have a higher potential to emit.

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<sup>108</sup> 87 FR 74732-74733 (December 6, 2022).

- The commenter conducts wellhead LDAR inspections currently. The latest data set shows that less than 10% of inspections find an actionable leak and only 5% of the leaks exceed 6 scf/hr. The commenter agrees with wellhead inspections, and the commenter conducts a robust wellhead maintenance program as a business best practice. While the commenter has periodically found, measured, and repaired emissions at their wellheads, they are not nearly as material of an emission source as the production equipment. And the leaks have found from wellheads represent a small percentage of overall leaks, which itself is a relatively small percentage of the commenter's overall emission inventory as determined through measurement campaign.

Response II-4-41: The EPA disagrees. As discussed in the December 2022 Supplemental Proposal, EPA evaluated the cost-effectiveness of various OGI frequencies and found that semiannual OGI monitoring is cost-effective.<sup>109</sup> In fact, EPA additionally found that the cost of quarterly OGI monitoring was also reasonable compared to a baseline level of no monitoring. However, the incremental value of going from semiannual monitoring to quarterly monitoring was outside the range of costs the EPA has found to be reasonable for this source category. Instead, the EPA evaluated whether the addition of less expensive AVO inspections would be reasonable and EPA found that the addition of quarterly AVO to semiannual OGI monitoring was cost-effective and was determined to be BSER for this category of well sites.

#### 4.1.3.6 Well sites with Major Production/Processing Equipment and Centralized Production Facilities.

Comment: Commenters (2177-Ute Indian Tribe, 2433-EDF et al., 2351-Jonah Energy LLC) express support for the proposed monitoring requirements for well sites with major production and processing equipment.

Commenter (2177-Ute Indian Tribe) agrees that quarterly OGI surveys are reasonable for well sites and centralized production facilities with major production and processing equipment, but bimonthly AVO inspections are not necessary combined with the quarterly OGI survey. The quarterly OGI requirement should suffice, in the commenter's opinion. If the requirement is kept, the commenter recommends adding language to allow for monitoring survey to be conducted "when personnel is on site, or bimonthly, whichever is less frequent."

Commenter (2351-Jonah Energy LLC) agrees with, and currently conducts, OGI inspections at well sites with production and processing equipment.

Commenter (2433-EDF et al.) supports EPA's subcategorization of well sites, which ensures that more complex sites and those with failure-prone equipment are subject to quarterly OGI and bimonthly AVO.

Response II-4-42: As discussed in the December 2022 Supplemental Proposal, the cost of quarterly OGI with bimonthly AVO inspections was found to be reasonable and was determined to be BSER.<sup>110</sup> In the final rule, the EPA is finalizing the work practice standards for monitoring and repairing (including replacing) fugitive emissions components at fugitive emissions

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<sup>109</sup> 87 FR 74732-74733 (December 6, 2022).

<sup>110</sup> 87 FR 74733-74736 (December 6, 2022).

components affected facilities located at well sites and centralized production facilities, as proposed in the December 2022 Supplemental Proposal. This includes requiring well sites with major production and processing equipment and centralized production facilities to conduct quarterly OGI (or EPA Method 21) monitoring combined with bimonthly AVO inspections.

Comment: Commenter (2279-U.S. Small Business Administration) asks EPA to consider whether there can be a further subcategorization of well sites with major equipment such that some sites might have bimonthly AVO and semiannual OGI. The commenter also suggests that EPA clarify that sites can change between subcategories, and thus change monitoring requirements, as equipment is installed and removed from the site.

Response II-4-43: The EPA developed well site model plants for the December 2022 Supplemental Proposal that were believed to be representative of common well site configurations. The well site model plants developed were not expected to represent every possible well site setup, but the distinct model plants that were developed were designed to account for various equipment types located at sites ranging from single wellhead only well sites and small well sites to complex sites with various major production and processing equipment known to be sources of large emissions.

The final rule at §60.5420b(c)(14)(iii) requires the owner or operator to track and record the removal of all major production and processing equipment such that the well site contains only one or more wellheads. Conversely, if major production and processing equipment is subsequently added back to the well site, record the date that the first piece of major production and processing equipment is added back to the well site.

#### 4.1.3.7 Small/Marginal Wells

Comment: Commenters (2157-Division of Air Pollution Control Tennessee Department of Environment & Conservation, 2168-Indiana Oil and Gas Association (INOGA), 2172-KOGA, 2179-KIOGA, 2237-Industrial Commission of North Dakota, 2186-Missouri Department of Natural Resources, 2204-LIP, LLC), 2205-Kriebel Well Services, Inc., 2211-Lambda Energy Resources, 2219-Wyoming Oil and Gas Conservation Commission (WOGCC), 2220-Wyoming Department of Environmental Quality, 2238-Southeastern Ohio Oil and Gas Association (SOOGA), 2248-North Dakota Petroleum Council (NDPC), 2249-NACAA, 2257-Michigan Oil and Gas Association (MOGA), 2279-U.S. Small Business Administration, 2288-North Dakota Department of Environmental Quality, 2294-Ohio Oil and Gas Association, 2295-Timothy Hauck, 2297-Petro-Vest, 2308-National Stripper Well Association, 2310-Montana Department of Environmental Quality (DEQ), 2314-Miller Energy Company, 2321-Apollo Exploration and Development, Inc., 2325-Aclima, 2330-Kentucky Division for Air Quality, 2353-CrownQuest Operating, LLC., 2401-State of Wyoming, 2403-PAO, 2437-Muskegon Energy Company (MEC), 2438-Muskegon Operating Company (MOPC), 2439-State of Michigan Department of Environment, Great Lakes and Energy, 2713-Northeast Natural Energy LLC, 3185-Lease Management, Inc) recommend that EPA maintain an exemption for low production wells. This exemption has been discussed between industry and EPA for several years. This is meaningful relief for small businesses with minimal potential impact from exempting the wells from compliance requirements.

Commenter (2157-Division of Air Pollution Control Tennessee Department of Environment & Conservation) believes EPA should reconsider its removal of the exemption for low-producing well sites. The commenter notes that there are 16,434 wellheads within the state, and removal of the exemption is likely to add substantially to the state's permitting and compliance workload.<sup>111</sup> The commenter notes that cost effectiveness alone may not consider the ability of a single wellhead-only site, or of a multiple well-head only site with a small number of low producing wells, to afford the cost of compliance, since a small facility's ability to comply depends not only upon the cost per ton but also the total cost of compliance and the revenue generated by the site. The commenter urges EPA to consider not only the cost effectiveness for the regulated entity, but also the cost to delegated air programs that have seen relatively flat federal funding support under Section 105 of the CAA for about two decades.

Commenter (2168-INOGA) adds Illinois Basin crudes are typically undersaturated with associated gas. The initial gas to oil ratios is typically in the 300-400 cubic feet/bbl range, while greater than 1,000 cubic feet/bbl in other basins. In older Illinois Basin waterfloods the gas to oil ratios is too low to reliably operate a separator. For example, an operator made a discovery in 1974 that produced 10 cubic feet per bbl upon initial production. This well is still producing with virtually no associated gas produced. Requiring additional regulations on this type of low production well is not cost effective or provides meaningful environmental benefits.

Commenters (2168-INOGA, 2172-KOGA) state small operators cannot afford to perform OGI surveys, and it is often not available. Each FLIR camera cost more than \$90,000 and requires training to properly operate the equipment. Utilizing EPA Method 21 requires each operator to pay an outside contractor to visit each location with monitoring equipment and produce a report of leaking components. Because of the size of a single wellhead well site, particularly those found in the Appalachian and Illinois Basins constructed of less than 120 total components (including fewer than 25 valves), a brief walk around the surface wellhead and associated equipment by the operations team allows for easy discovery of most gas leaks. The natural composition of the gas in these basins gives it a distinctive odor without any additives and the smallest leaks allow even an untrained person to sense if a leak is present through their olfactory senses.

Commenters (2168-INOGA, 2172-KOGA) states the next commonsense step would be to narrow the location by sound, or if too small to hear, soap bubbles can be applied. Plumbers have been using soap bubbles to identify leaks in domestic low pressure plumbing for decades and the plumbing of a low-pressure low volume gas well is essentially the same. The design gas pressure for residential appliances is approximately 7 inches of water column, which is 0.25 psig. If soap bubbles can detect a gas leak at 0.25 psig, the soap bubbles will also be able to detect a gas leak at this low pressure well sites.

Commenters (2168-INOGA, 2179-KIOGA, 2205-Kriebel Well Services, Inc., 2257-MOGA, 2279-U.S. Small Business Administration, 2283-Endeavor Energy Resources, 2308-National Stripper Well Association, 2325-Aclima, 2353-CrownQuest Operating, LLC) express concern

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<sup>111</sup> TDEC's Division of Air Pollution Control has no information on the size of specific oil and gas wells within the state, but TDEC's Division of Mineral & Geologic Resources advises that Tennessee's wells tend to be small, lower-producing operations.

over the fugitive emissions monitoring requirements, especially as they relate to small businesses.

Commenters (2179-KIOGA, 2283-Endeavor Energy Resources) ask that EPA simplify and clarify the LDAR requirements. The commenters find EPA's proposed approach confusing and asks that the requirements in any final rule be simplified. Upstream operators are frequently small businesses and will have to track monitoring requirements across many sources and facilities.

Commenters (2168-INOGA, 2179-KIOGA, 2205-Kriebel Well Services, Inc., 2257-MOGA), 2279-U.S. Small Business Administration, 2308-National Stripper Well Association, 2325-Aclima, 2353-CrownQuest Operating, LLC.) state small entities remain concerned about the cost of OGI requirements and their ability to procure the services of OGI contractors, particularly within the timeframes that EPA's proposal would require. Although EPA's analysis is that OGI is cheaper than AVO inspection, the small businesses with whom the commenter (2279-U.S. Small Business Administration) has consulted insist that AVO inspections are generally preferred. They can be done more frequently and without specialized equipment, more people can be trained to perform them properly, and they are well-suited to detect the leaks most likely to occur at small sites.

Commenters (2172-KOGA, 2237-Industrial Commission of North Dakota, 2288-North Dakota Department of Environmental Quality) state EPA's premise seems to be that every wellhead will develop a leak every year and the more times a site is surveyed the more leaks are found. The commenter believes these are incorrect assumptions. A wellhead constructed properly has no reason to develop a leak without some significant "catastrophic" occurrence such as a tree falling on it.

Commenters (2237-Industrial Commission of North Dakota, 2288-North Dakota Department of Environmental Quality) provide an anecdotal example, a small shallow gas field in S.E. Kentucky drilled in 2005. The wellheads are constructed with between 30 and 45 components including between six and eight 1" and 2" valves. All 19 wells have been checked for leaks multiple times over the last ten years using AVO and soapy water, and there have never been any leaks found. These inspections are performed by the operator because the company is a good environmental steward and to prevent the loss of revenue from equipment leaks. Commenters (2237-Industrial Commission of North Dakota, 2288-North Dakota Department of Environmental Quality) have only observed a handful of wellhead-only well sites with fugitive emissions over the past few years. It appears that in those handful of cases that the emissions were more a result of specific operator error rather than being indicative of widespread fugitive emissions at well sites.

Commenter (2179-KIOGA) states EPA never took any significant data to identify the emissions profile of low production wells. It has relied on specious studies by environmentalists, used outdated studies from the mid-1990s that were never designed for regulations, and in its most recent NSPS OOOOa proposal relied on data from about 25 wells in one area, half of which do not appear to be low production wells. Only the DOE conducted a study of emissions from low production wells. That study was complete in May 2022. If any federal agency is creating regulations that have the capability of wiping out three-quarters of the facilities in an industry, it must have a full understanding of the industry and its regulatory actions. This has not been done.

Commenter (2186-Missouri Department of Natural Resources) encourages EPA to fully consider whether the inclusion of these sites will result in meaningful environmental protection or improvement when weighed with the costs that both industry and the regulating agencies will bear. Due to the low emissions expected from these sources, the Air Program does not expect measurable improvement to air quality by regulating these sources and requests EPA to consider removing requirements on these sites in the final action.

Commenter (2205-Kriebel Well Services, Inc.) states their main concern is that there appears to be a disconnect with understanding the differences between a large natural gas and oil producer (*i.e.*, Shell and BP) and a small marginal natural gas and oil producer (approximately 100 employees or less). This misunderstanding appears to have led to an excessive NSPS proposal that imposes a strong cost burden on the marginal well producer.

Commenters (2211-Lambda Energy Resources, 2257-MOGA) are concerned regarding the costs of maintaining a LDAR program, including the costs of surveys, data capture and collection, reporting and variable costs regarding repair as non-marginal well progress into the marginal and low production category. Low production and marginal wells cannot internalize the same regulatory costs as non-marginal wells.

Commenter (2211-Lambda Energy Resources) state regulations that might be appropriate in the Permian Basin are not necessarily feasible for lower pressure, less productive Michigan wells. Most hydrocarbon emissions come from newer, higher production (and higher pressure) wells, rather than from lower pressure, lower production sources. The proposed regulations are geared toward higher producing, higher pressure wells, and not to marginal wells.

Commenter (2219-WOGCC) notes in Wyoming there are over 6,000 of these low producing wells. In 2021 they produced over 7,000,000 bbls of oil and 20,000,000 mcf of gas. These are wells that are typically operated by small, local Wyoming businesses. These small business owners and their employees live and work in the local communities. The premature shut in or plugging of these wells caused by the proposed rule will cost the local communities jobs and revenue.

Commenter (2219-WOGCC) continues, orphaned wells will become the responsibility of the BLM in the case of federal or tribal wells and the commenter in the case of fee or state wells. Forfeited bonds may cover some of the costs to plug the orphaned wells and reclaim the sites, but it is likely other sources of funding will need to be utilized to plug these wells. The premature shut in and plugging of these wells will result in lost royalties and taxes, likely far more than what little may be gained by capturing the small amount of gas that is not already sold from these low producing wells. Operation of these wells also generates additional revenue in local communities in the form of sales taxes and spending by their employees in local communities.

Commenter (2220-Wyoming Department of Environmental Quality) is concerned how the compliance requirements in the proposed regulatory text for NSPS OOOOb and EG OOOOc would affect “low production” wells or smaller companies. While EPA revised some of its proposed monitoring and repair requirements for well sites in the supplemental proposal from what was required in the 2021 proposed rule, there are still potentially onerous requirements in the proposed NSPS OOOOb and EG OOOOc regulatory texts. These requirements could affect many stripper wells in Wyoming (defined by the Wyoming Oil and Gas Conservation

Commission (WOGCC) as wells that produce an average of 15 barrels of crude oil (BBLs) or less per day) and some very small-scale, independent well site operations that strictly operate on a single owner's private property. According to the commenter, Wyoming has approximately 6,524 stripper wells.

Commenter (2249-NACAA) states one area of the proposal that offers a measure of uncertainty is the extension of wellsite monitoring to apply to the smallest wells. On November 23, 2022<sup>112</sup>, the commenter requested an extension of the comment period for this proposal in order to analyze technical aspects such as the implications of this extension of applicability. EPA denied this request on February 3, 2023.<sup>113</sup> As such, the commenter cannot offer a detailed response about the implications of discontinuing waivers for these sources, or unqualified support for these provisions of the proposal if they are not given the resources to succeed. Anecdotally it appears as though this expansion could represent a dramatic increase in the responsibilities falling to state and local clean air agencies to permit, monitor, inspect, and assure compliance by, these wells. The commenter champions the goal of reducing wellsite emissions, but new programs will require new resources, and EPA cannot ignore the possibility that this provision could overburden them beyond state and local agencies' ability to successfully implement it. EPA should better understand these implications, and where they increase the responsibilities of our agencies, EPA should take steps to assure those responsibilities are met with appropriate federal support and resources for implementation.

Commenter (2257-MOGA) believes the EPA has not considered the broader economic and environmental impacts the early plugging of wells may have in Michigan. Further, the EPA has not provided a cost-benefit analysis showing a valuable correlation between any possible benefits of expanding the NSPS regulations to the economic and environmental costs associated with additional drilling to offset lost production from the early plugging of wells.

Commenter (2308-National Stripper Well Association) adds the vast majority of those small operators have actively producing stripper wells in the United States that produce 15 barrels of oil equivalent/90 MCF of gas or less per day. In fact, almost 80 percent of the oil and gas infrastructure in the U.S. are stripper wells.

Commenter (2314-Miller Energy Company) states the cost-benefit analysis did not consider operators like Miller Energy that are comprised of marginal-stripper wells producing ½ to 2 BOED on average. The commenter's wells are vastly different from super-emitters yet the bill recommends they be treated the same. With less production comes less emissions per well/facility. With smaller production outputs also comes less available profit margin to recapture the capital investments required to install the proposed monitoring and field equipment.

Commenter (2314-Miller Energy Company) would like the EPA to consider excluding marginal wells from this regulation. If existing marginal wells cannot be excluded, the commenter would like to propose a tiered system that uses production quantities and potential emissions to determine the level of compliance requirements. With reduced production and emissions,

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<sup>112</sup> This letter is available online at <https://www.4cleanair.org/wp-content/uploads/NACAA-OilandGasSectorExtensionRequest-11292022.pdf>.

<sup>113</sup> This letter is available online at <https://www.4cleanair.org/wp-content/uploads/EPA-methane-extension-denial.pdf>.



marginal wells should require less monitoring and controls than the super emitters. The removal or reduction of regulation for marginal wells will not impact the EPA's goal to reduce methane emissions as they have a de-minimis impact. The removal will also reduce state and federal tax spending for the oversight required to manage this program.

Commenter (2321-Apollo Exploration and Development, Inc.) notes that the proposed rules are designed to be one size fits all which does not make sense when you compare emissions from a large production well to a marginal well. The economics of compliance and the emissions reductions will be drastically different, yet the proposed rules seem to ignore that fact. This will discriminate against small businesses and make fair competition in a free-market economy unattainable. Depleted reservoirs/marginal wells have less pressure, make less production and in effect have smaller potential for emissions. By making additional costs, some marginal wells may end up being plugged prematurely which wastes natural resources as well as ignores mineral owners correlative rights. Prematurely plugged wells are a detriment not only to the industry but also to the local, state and national economy.

Commenter (2321-Apollo Exploration and Development, Inc.) iterate a significant one-time financial and environmental cost is required to drill a single well. Over-regulation of marginal wells, as proposed in Subpart OOOOb and Subpart OOOOc, will lead to the early plugging of wells while the remaining assets are still economically viable to recover. This will prevent small business operators from recovering their initial capital investment. Also, the early plugging of marginal wells, while still economically viable, will likely exacerbate the need to drill additional wells to meet consumer demand. The unrecovered initial capital investment from drilling a well, combined with the demand to drill additional wells would yield a spiraling economic decline for small businesses by not allowing them to manage profit revenue from existing marginal wells for investment in new wells to meet future demand. This impact would have a rippling effect through our nation as oil, natural gas, gasoline and petroleum derivative prices would skyrocket based on declining supply and rising demand.

Commenter (2403-PAO) notes the DOE study provides data showing that marginal well sites overwhelming fall below the 3 tpy of methane emissions (as provided in the 2021 Proposal) based on actual sampling.<sup>114</sup> The commenter requests EPA incorporate thresholds at which the requirements for fugitives emission monitoring no longer applies. These thresholds should use terminology that is understandable, and useable by small oil and gas businesses so they can easily comply, avoiding the need to hire consultants which will increase the cost of compliance. As an alternative, EPA could develop a framework that provides smaller operators the option to use in lieu of conducting detailed calculations to determine if the methane emission at their site exceed the proposed thresholds. This would benefit state delegated agencies to better manage the large number of existing facilities in their state.

Commenters (2179-KIOGA, 2248-NDPC, 2310-DEQ, 2713-Northeast Natural Energy LLC) argue the proposed monitoring requirements and schedule are excessive for these sites, provide little environmental benefit, and are prohibitive for small owners and operators and will result in the end of their operations. Commenter (2179-KIOGA) states it is an issue when the regulated emission is methane which triggers a nationwide existing source requirement where the brunt of

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<sup>114</sup> U.S. Department of Energy, National Energy Technology Laboratory, Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells, April 28, 2022.

the impact falls on the 750,000 low production wells that average about 2.5 barrels/day and 25 mcf/d.

Commenter (2179-KIOGA) urges the EPA to modify the rule to include a production rate threshold which would exempt wells making less than 6 BOEPD.

Commenters (2168-INOGA, 2172-KOGA) support EPA's position that operators should perform one leak inspection on low production wells to ensure that no emission sources exist and then do not need to perform additional inspections and maintain associated documentation. This will be a significant step in reducing the complexity of the regulations. The commenters state most of the low production wells are low pressure, requiring artificial lift, and have a low Gas to Oil Ratio (GOR). The PTE from the low production wells is low, yielding reduced benefits for the cost incurred and efforts employed. Dedicating resources to emission sources with a greater PTE will yield greater reduction in emissions. The commenters recommend that the threshold for low production wells match the tax definition of a stripper well for consistency, 15 BOED.

Commenter (2179-KIOGA) states results from the DOE third-party methane emission study of low production wells and facilities indicates that wells producing less than 6 BOED would emit less than 3 tpy of emissions. The emission calculation is based on Subpart W, but most low production existing well producers fall below the Subpart W reporting threshold and the cost and complexity of completing Subpart W reporting for these operators is not just burdensome, it is cost prohibitive for many small businesses. If EPA needs to design a low production well program, it should utilize the emissions profile information developed by the DOE and then focus on the most cost-effective options to address the key sources.

Several commenters support EPA exempting very small wells and establishing subcategories of sources for low production wells and small well sites that have less onerous monitoring, recordkeeping and reporting requirements. This will be a benefit to small business entities with limited staffing resources. In addition, EPA could unintentionally incentivize small businesses to abandon low production wells without these exemptions. This would be a lose-lose situation for small businesses and the environment.

Commenter (2205-Kriebel Well Services, Inc.) notes the DOE study report provides a perspective for an effective low production (marginal) well leak management program that is far less costly compared to the very expensive OGI program. This includes:

1. Routine AVO inspections of tanks and other equipment to assure proper operation,
2. Routine AVO inspection of wellheads to assure proper operation,
3. Periodic simple testing (*i.e.*, use of soap & water bubbles), to check for leaks as needed, and
4. Use of production rates and equipment counts to determine the applicability of the program, rather than costly emissions calculations that were not done for the low production well.

Commenter (2205-Kriebel Well Services, Inc.) asks the EPA to please consider AVO as the means to detect leaks for the marginal well producer. Anything above and beyond simple AVO proves to be unnecessary and extremely cost burdensome.

Commenters (2257-MOGA, 2437-MEC) suggest the EPA consider past small businesses' documented emission reductions as a factor in their required fugitive monitoring schedule. Once again, the EPA appears to be penalizing small businesses that have adhered to requirements outlined in the current Subpart OOOOa and previous Subpart OOOO rule. These small businesses feel "targeted" for their emission reduction efforts based on past regulations and the commenters wonder if it will end. The commenter attended several meetings with the EPA during which, the EPA admitted the bulk of emissions come from a small group of sites and companies. For these reasons, commenter (2257-MOGA) believes the EPA should avoid penalizing small businesses with documented emission reduction efforts with an "Exemption Classification" for fugitive emission monitoring.

Commenters (2297-Petro-Vest, 2321-Apollo Exploration and Development, Inc., 2437-MEC, 2438-MOPC) argue it is unfair and unwise to treat marginal wells in the same manner as larger producers. Marginally producing wells (15 BOEPD/90 MCFPD or less) must be exempt from EPA rules because the emissions are insignificant and the rules would make the wells uneconomic. There must be a regulatory "off ramp" for wells such as ours that are low producers.

Commenters (2295-Timothy Hauck, 2403-PAO) notes that essentially, EPA is placing the same requirements on facilities that produce thousands of barrels of oil per day in the same category as a marginal well that produces 1.4 barrels of oil per day (Bpd) while claiming the requirements are cost effective for these lower producing, marginal wells. A one-size-fits-all rule that applies to all wells is not appropriate or reasonable, is an inefficient use of manpower and funds, and fails to understand the unique aspects of the lifespan of an oil and gas well as production declines over time. The expansive regulations provided in the proposed rule will lead to service and equipment availability issues that will unnecessarily increase costs for the low producing, marginal well operator, and it may limit the ability of operators to comply with the proposed rule and/or continue to operate. Supply chain issues are still a significant issue for our members, and it is more difficult for smaller operators to secure services or equipment (as compared to larger companies).

Commenter (2204-LIP, LLC) states a well making 200 barrels of oil or 2,000 million cubic feet of gas a day does not have the same emissions and economics as a well making 5 barrels or 5 million cubic feet a day. The majority of wells in this county are more of the later, namely marginal wells. The commenter only does oil field consulting with marginal well producers. The proposed regulations would force the plugging of most of the wells they produce as it would not be economically justified to make these upgrades. This in effect would wipe out over half of Michigan's natural gas production, which is badly needed to heat homes in this climate and generate electricity.

Commenter (2437-Muskegon Energy Company (MEC)) states the economic viability of companies relies on efficient and low-cost operations. The commenter opposes the proposed regulations known as NSPS OOOOb and EG OOOOc. The proposed rules will have significant detrimental impacts on our economic viability, costs, overhead, reserve recovery, and plugging costs. The regulations will unnecessarily, unreasonably, and disproportionately raise company's costs and jeopardize our ability to produce marginal wells. The commenter's company will not be able to absorb the additional regulatory costs and the proposed regulations will put them out of business.

Commenters (2297-Petro-Vest, 2437-MEC) are not in agreement with the process or the proposed regulations. Many of the proposed regulations are not feasible and/or do not pass costs-benefits analysis. The EPA's proposed regulations are a "one size fits all" approach and do not adequately take into account smaller companies and marginally producing wells.

Commenter (2713-Northeast Natural Energy LLC) argues a single well or multiple well sites that do not exceed 15 bbls of oil per day or 90 mcf of natural gas per day should be considered as small well sites and be subject only to the quarterly AVO requirement. Sometimes it is not clear if a quarterly OGI survey requirement can always be satisfied using method 21 in lieu of a FLIR/OGI instrument.

Commenter (2439-State of Michigan Department of Environment, Great Lakes and Energy) states the following adjustments to the proposed rule would be equally protective and have less impact to production and small businesses:

- Additional consideration for economic solutions, such as allowing AVO and reasonable reporting frequency for compliance at Small Well Sites;
- Less frequent OGI verification;
- Modification of the small well site definition to include additional pieces of equipment;
- Acceptance of state oil and gas program approved plans and plugging records;
- Consideration of production levels.

Commenter (3185-Lease Management, Inc.) states the proposed rules are based on 1974 data from a large producer in Fort Worth Texas, which is not valid for current operations and totally irrelevant to current operations for small, marginal producers. Ignoring the differences between large 1974 operations and 2023 small operations is totally unacceptable and should never be used for proposing new rules. The DOE recognized these flaws and performed a current, technically sound study of actual emissions from small producers across the country. This data was made available to the EPA last year and should be utilized as a basis for new rules, not 49-year-old data. The proposed rule discriminate against small operations and will shut down small businesses like ours. As a marginal well operator in Michigan, the commenter notes that it can understand and can manage logical regulations, but these rules are simply logical for small producers. The EPA did not allow enough time for me to fully understand all the details, but on the surface these proposed rules fail the logic test. The EPA is ignoring the best available data, using 49-year-old data, and rushing forward with bad rules. The commenter questions the following:

1. The EPA using this 49-year-old irrelevant data as a basis.
2. The EPA ignoring the current data generated by the DOE.
3. Is this EPA intentionally trying to shut down small businesses?
4. Why is the EPA rushing these rules forward?
5. How does the EPA rationalize using 49-year-old data as a one size fits all approach to current small producers?

The comments submitted by the IPAA and MOGA have more detailed comments of the commenter's concerns.

Response II-4-44: As EPA has discussed,<sup>115</sup> emissions from lower producing wells can be a significant source of fugitive emissions and EPA did not find that production rates correlate to the amount of fugitive emissions. Therefore, the EPA is establishing a fugitive emissions monitoring and repair program in the final rule that is based on distinguishing among well sites with different equipment and component counts.

The EPA is maintaining AVO inspections for fugitive emissions monitoring for single wellhead only well sites and small well in the final rule. The specific requirements being finalized for single wellhead only well sites and small well sites are described in section X.A.1.a.ii of the preamble to the final rule for new sources under NSPS OOOOb and in section X.A.1.b.ii of the preamble to the final rule for existing sources under EG OOOOc.

As stated in the November 2021 Proposal, the EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. The EPA discusses the financial conditions of marginal wells in section 5.2 of the RIA. There are many factors that might affect the profitability of marginal wells and the decision to shut-in and plug a well, making it difficult to determine the full impact of regulation on the financial status of marginal well owners. The EPA has also taken steps to include regulatory flexibility and streamline recordkeeping requirements in the fugitive emissions standards of the final rules.

Comment: Commenters (1611-East Liberty Presbyterian Church, 1648-Presque Isle Audubon Society and PA Audubon Council, 1649-The Sisters of St. Francis of Philadelphia, 1655-AAP, 2028-Westmoreland Marcellus Citizens' Group, 2185-New York State Common Retirement Fund (CRF), 2203-Ceres, Inc., 2212-Union of Concerned Scientists, 2226-Thermo Fisher Scientific, 2236-Physicians for Social Responsibility Pennsylvania (PSR), 2285-Bailard, 2299-NEI Investments, 2302-Texas State Representatives, 2303-NTAA, 2364-CleanEarth4Kids.org, 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al., 2429-Wyoming Outdoor Council, 2433-EDF et al, 2461-Conservatives for Responsible Stewardship, 2766-1000 Grandmothers for Future Generations) support EPA's elimination of the exemption from fugitive monitoring and repair for low production or marginal wells—including well sites with a potential to emit (PTE) of less than 3 tpy—and are encouraged that EPA is requiring regular fugitive emissions monitoring and repair for all well sites regardless of their PTE or production level.

Response II-4-45: The EPA acknowledges the comments. The final rule maintains the requirements as proposed in the December 2022 Supplemental Proposal, specifically requiring regular fugitive emissions monitoring and repair for all fugitive emissions components affected facilities.

Comment: Commenters (1643-Ohio River Valley Institute (ORVI), 1648-Presque Isle Audubon Society and PA Audubon Council, 1655-AAP, 2199-Rocky Mountain Farmers Union, 2226-Thermo Fisher Scientific, 2429-Wyoming Outdoor Council, 2433-EDF et al, 2462-Cynthia Walter) note lower-producing wells contribute a significant amount of methane emissions. Nationally, low producing (marginal) wells account for only 6 percent of oil and gas production,

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<sup>115</sup> 87 FR 74731 (December 6, 2022).

but are responsible for roughly 50 percent of all wellsite pollution.<sup>116</sup> Marginal wells represent an outsized source of leaked methane and GHGs relative to their production benefit. Given this context, the commenters think it's appropriate to have regular inspections on all sites with leak-prone equipment (with more frequent inspections required for sites with more significant potential for emissions).

Response II-4-46: The EPA agrees that emissions from lower producing wells can be a significant source of fugitive emissions. The EPA is maintaining AVO inspections for fugitive emissions monitoring for single wellhead only well sites and small well in the final rule. The specific requirements being finalized for single wellhead only well sites and small well sites are described in section X.A.1.a.ii of the preamble to the final rule for new sources under NSPS OOOOb and in section X.A.1.b.ii of the preamble to the final rule for existing sources under EG OOOOc.

Comment: Commenters (2038-Private Citizen, 2303-NTAA, 2433-EDF et al, 2460-Private Citizen) emphasize EPA has historically underestimated methane emissions from the oil and natural gas industry and that the sources' emissions are likely causing even more harm than previously believed. In addition, the commenters note that marginal wells can have high methane emissions and should be included within programs such as fugitive emissions leak detection and repair that require a root cause analysis to ensure that an owner or operator can identify equipment and operational issues that could trigger high emission events. They also noted that the distribution of emissions rates is skewed so the speed of detecting and stopping large emission sources is critical for reducing total emissions.

Commenter (2038-Private Citizen) gives an example on a facility grossly underreporting annual methane emissions, in response to the NJDEP request for comments on the Tennessee Gas Pipeline TGP) Title V Operating Permit in Wantage TWP, New Jersey. In this comment, the commenter detailed out based on TGP's own documentation and specifications provided to FERC that the operator has been publishing false impossibly low methane emissions in a range between .4 tons to 1.5 tpy from 2009 through to 2023 when the potential emissions as identified by TGP to FERC was expected to be greater than 650 tons of methane each year. NJDEP issued their response to comments on 1/19/2023<sup>117</sup>.

Th commenter (2038-Private Citizen) has discovered and uncovered through research and interaction with agencies:

1. Currently, only a subset of the natural gas fired compressor station facilities are being required to provide annual GHG and HAP emissions estimates each year.
2. The few stationary sources that are required to provide annual estimate emissions severely underreport annual emissions based only on combustion emissions and not venting or leaking fugitive emissions. In all of the facilities that the commenter has reviewed in many different states, it is clear that none of the facilities the commenter has reviewed report emissions anywhere close to estimate or even actual emissions each year.

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<sup>116</sup> Omara, M., Zavala-Araiza, D., Lyon, D.R. et al. Methane emissions from US low production oil and natural gas well sites. Nat Commun 13, 2085 (2022). <https://doi.org/10.1038/s41467-022-29709-3>.

<sup>117</sup> <https://dep.nj.gov/wp-content/uploads/boss/public-notices/final-hearing-officer-report-1-19-23-signed.pdf>.

3. There are many facilities within the natural gas supply chain that are not required to provide any estimate emissions. Most notably for New Jersey are natural gas electric compressor station facilities. While these facilities can emit more than 100 tons of methane each year along with the associated HAP (such as benzene) due to leaking and venting fugitive emissions, there are no requirements for these facilities to report their annual emissions.

Yet, the commenter (2038-Private Citizen) has found operational electric facilities that the commenter has visited which routinely smell like major gas leak even 2,000 feet away from the facility during times when demand is high (indicating that emissions is not blowdown, but just fugitive leaks) such as on cold winter mornings. Commenter (2038-Private Citizen) has also uncovered new proposed electric facilities that specify the facility will emit more than 100 tons of methane each year (example is TGP CS-327, where TGP provided in its submissions to FERC indicating that CS-327 will emit 142 tons of methane each year). Yet these facilities remain undocumented, unmonitored and none existent in the EPA GHG stationary source inventory.

Of all the facilities that Commenter (2038-Private Citizen) has researched and or visited, the few that have to report, always underreport by at least a factor of 50; that the emissions do not include fugitive emissions and that the reporting is inconsistent across facilities owned by different companies and also varies by which state the facility resides in.

Commenter (2460-Private Citizen) adds to ensure under-reporting ends, the following provision should be regulated:

- Monitoring of emissions need to be continuous over sufficiently long periods of time to obtain information about emissions during abnormal, as well as normal, operating conditions.
- Alarm systems are needed to alert facility personnel when emissions unexpectedly rise.
- Occasional independent checks are needed to determine if on-site monitoring systems are in compliance.
- Emissions from small operation should be allowed to be significantly greater than those from large ones. The current situation is so dire as to require that all emissions be limited to the greatest degree possible.
- The EPA should consider using data obtained by citizens using techniques such as OGI to track leakage at downstream sites such as compressor stations. This could identify areas that need to be formally monitored, perhaps using services from organizations such as Climate TRACE.

Response II-4-47: The EPA acknowledges the commenters' concerns and notes reports cited to and the recommendations provided.

Comment: Commenter (2254-Permian Basin Petroleum Association (PBPA)) states EPA's proposed monitoring schedule is challenging for many basins, including the Permian Basin, due to the distance between sites. There are not enough LDAR technicians in the basin to comply with the new requirements and, even if there were, it would be prohibitively expensive for producers. EPA should instead allow periodic inspections to occur through areal fly-overs or

through the use of other remote technology and only require in-person monitoring on a much less frequent basis.

Commenter (2254-PBPA) states their environmental partnerships have demonstrated that emissions are much lower than EPA projects. The Environmental Partnership, which launched in 2017, has surveyed over 340,000 sites and over 750 million components. The average leak rate from companies participating in the partnership is 0.08%. The partnership is comprised of over 95 companies in industry, from operators to midstream. EPA used the FEAST model, but has not explained why the FEAST model is preferable to data collected by the Environmental Partnership, calling into question the basis for its BSER proposals.

Response II-4-48: The final rule at §60.5398b includes provisions for owners and operators to apply to use alternative technologies to meet the standards that apply to fugitive emissions components affected facilities.

With respect to FEAST modeling, the EPA noted in the December 2022 Supplemental Proposal preamble that although EPA used this model for the purposes of evaluating the various fugitive emissions monitoring and repair programs, similar results are expected using other available modeling tools.

#### 4.1.3.8 Initial and Subsequent Monitoring Surveys

Comment: Commenter (2453-Carbon Mapper and RMI) support the monitoring of small well sites within 90 days of startup or modification of well sites and compressor stations, as long standing and/or undiscovered leaks may generate considerable emissions over time. This is particularly true of remote sites not frequently visited by operators otherwise.

Response II-4-49: In the final rule, the EPA has retained the requirement to conduct the initial monitoring survey at single wellhead only sites and small sites, multi-wellhead only well sites, well sites or centralized production facilities that contain major production and processing equipment, and compressor stations within 90 days of the startup of production.

Comment: Commenter (2399-GPA Midstream Association) proposes that EPA provide 180 days to conduct the initial fugitive emissions monitoring. Conducting compliance monitoring is a lengthy process requiring the development, coordination, and scheduling of internal and contracted services. Often, these monitoring services must be planned and scheduled more than 90 days in advance. Here, affected facilities and service contractors must first develop and update required systems and plans under proposed §60.5397b(b)-(d) for newly affected facilities. Then they – along with the rest of the industry – must attempt to schedule contractors for the initial fugitive emissions monitoring. EPA should accept the initial fugitive monitoring results performed in accordance with NSPS OOOOa for sites constructed after the applicability date of NSPS OOOOb as those sites had to meet NSPS OOOOa requirements until NSPS OOOOb was finalized. Further, the fugitive monitoring requirements under both subparts are effectively the same.

Response II-4-50: The EPA disagrees and has retained in the final rule, the requirement to conduct the initial monitoring within 90 days of the startup of production. The EPA believes this



amount of time is sufficient for facilities to achieve normal operating conditions, but any additional beyond 90 days of startup would not allow for timely repair of any initial issues.

#### 4.1.3.9 Repair

Comment: Several commenters (2168-INOGA, 2172-KOGA, 2227-Western Energy Alliance, 2399-GPA Midstream Association, 2403-PAO, 2410-California Office of the Attorney General et al., 2428-API, 2433-EDF et al) suggest that EPA revise repair timelines under the final rule.

Commenter (2428-API) states the repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

Commenter (2428-API) states EPA's reason for requiring shorter repair timelines is "*so that the monthly AVO inspections do not overlap the repair schedule*".<sup>118</sup> This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

Commenter (2428-API) continues, while AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

Commenter (2428-API) offers the following suggested redline of §60.5397b(h):

(h) Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

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<sup>118</sup> 87 FR 74737.

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made no later than 30 calendar days after detection of the fugitive emissions.~~

~~(2) Repair shall be completed as soon as practicable, but no later than 15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and 30 calendar days after the first attempt at repair as required in paragraph (h)(1)(ii) of this section.~~

Commenter (2433-EDF et al) argues EPA’s definition of “first attempt at repair” is too broad and could allow actions without any probability of leading to a successful repair to be interpreted as an “attempt.” The commenter therefore recommends tying the attempted action to the outcome, which is a successful repair. EPA should include language that makes clear the “attempt” must be one that, if completed, would successfully mitigate the emissions. The commenter also encourages EPA to broaden the non-exhaustive list of examples. Many fugitive emissions will require repairs that are much more significant than the list EPA has included.

Commenters (2168-INOGA, 2172-KOGA, 2227-Western Energy Alliance, 2403-PAO) recommend that EPA standardize all leak repair times to be as soon as possible, not to exceed 30 calendar days. This will provide consistency with prior regulations and avoid confusion for operators as they are developing their compliance programs.

Commenter (2403-PAO) believes the proposed monitoring timeframes (e.g., quarterly, bimonthly and monthly AVO) and repair frequencies (e.g., within 15 days of inspection vs. first attempt at repair within 30 days and final repair within 30 days of first attempt) are confusing and may lead to non-compliance.

Commenters (2168-INOGA, 2172-KOGA) note the difference between the repair frequency for AVO (15 days) and OGI (30 days) in the rule. The commenters indicate that leaks discovered with AVO may be as difficult to repair as leaks discovered with OGI. The commenters recommend that the repair time for AVO should also remain consistent with OGI repairs, 30 days to attempt repair and 30 additional days to confirm the repair is complete.

Commenter (2433-EDF et al) notes EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions, with final repair required within 30 days of the first attempt, for a potential total of 60 days. The commenter believes this is unnecessarily long and could lead to large emissions going unmitigated for up to two months. Repair timelines can significantly affect overall mitigation,<sup>119</sup> and EPA’s projections of emissions reductions achieved by the rule assume only a 30-day delay between detection and repair.<sup>120</sup> EPA’s projected reductions will not be realized if repairs are allowed to extend beyond 30 days.

Commenter (2433-EDF et al) states a 30-day repair timeline is feasible and is already required by leading states, like Colorado and New Mexico.<sup>121</sup> The commenter therefore urges EPA to

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<sup>119</sup> See Felipe J. Cardoso-Saldaña, Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities 325 (2022), <https://chemrxiv.org/engage/chemrxiv/article-details/636d4595afea7fcd1c9f5f67>.

<sup>120</sup> See Supplemental RIA, *supra* note 110, at 228.

<sup>121</sup> See Colo. Code Regs. § 1001-9-D-II.E.7; N.M. Code R. § 20.2.50.116(E) (2023).

require a first attempt at repair within 15 days of detection and a final repair within 15 days of the first attempt, for a maximum of 30 days between detection and final repair.

Commenter (2433-EDF et al) argues EPA should eliminate the “technically infeasible” exemption language from the repair requirements and only allow extended repair timelines in the specified instances. This language is too open-ended and is not necessary given that EPA has already specified the situations in which a repair would be technically infeasible. Additionally, EPA should include a requirement that inspection crews attempt to complete repairs at the time leaks are detected when safe and feasible. This practice is already the norm for leading operators and should be encouraged by EPA.

Commenter (2433-EDF et al.) continues, EPA should also ensure that documentation and reporting occurs when an OGI or AVO survey detects emissions, but the operator determines that the emissions are from a permissible event or part of normal operations that does not require repair. This will help to align requirements with the alternative screening option while allowing EPA to track and ensure that operators are taking appropriate follow-up action after detecting emissions. The commenter also recommends that EPA require the initial monitoring survey to occur earlier so that companies can address problems sooner and mitigate potentially large emissions that would otherwise go undetected for up to 90 days.

Importantly, EPA should align OGI and AVO follow-up and repair requirements for control device failures with those described in section 60.5398b(b)(4)(iv). Misalignment between the scope of monitoring and follow-up and repair requirements between the OGI program and the alternative could disincentivize use of the alternative. The commenter therefore urges EPA to ensure control devices are monitored during OGI surveys for compliance with the requirements of section 60.5413b and are subject to parallel root cause and corrective action requirements if problems are detected.

Response II-4-51: The EPA believes 30 days is a necessary amount of time to complete the first attempt at repair after detection of the fugitive emissions with OGI or EPA Method 21, plus an additional 30 days to complete the final repair. Based on information from annual compliance reports, most fugitive emissions components repairs could be completed within 30 days, however, not all repairs are expected to be able to be completed within the first attempt of repair and therefore additional time is needed to ensure repairs are completed and would also eliminate the need for further delay of repair. Therefore, contrary to one commenter’s remark that allowing for final repair within 60 days could lead to large emissions going unmitigated for up to two months, the EPA disagrees, because as stated, most fugitive emissions are expected to be repaired in the first attempt.

Also, the EPA clarifies that when fugitive emissions are identified through AVO inspections, the EPA is requiring that repairs be completed within 15 days after the first attempt in order to not overlap the repair schedule of repairs of emissions detected with OGI or EPA Method 21. For single wellhead only well sites and small well sites, the issue the commenter mentions of detected emissions going unmitigated for up to two months would not occur because the rule requires quarterly AVO inspections and because the first attempt of repair is 15 days following detection of emissions and final repair is 15 days after the first attempt of repair for a total of 30 days. For multi-wellhead only well sites and well sites with production and processing equipment and centralized production facilities, the issue the commenter mentions would not be

an issue either because of the combination of AVO inspections and OGI monitoring, and specifically the fact that quarterly AVO inspections (for multi-wellhead only well sites) and bimonthly AVO inspections (for well sites with production and processing equipment and centralized production facilities) would pick up any large emissions occurring in that time frame and not go unnoticed.

Comment: Commenter (2172-KOGA) states because there may be an unusual circumstance where there is some failure of a part, such as a valve stem in a valve that is not readily available, leaks identified by AVO should be on the same 30-day schedule to attempt a repair and an additional 30 days to finalize a repair that is allowed leaks found with OGI.

Commenter (2436-Louis Pochet) adds well-head failure is common even for new wells, resulting in substantial fugitive emissions. For example, it has been reported that wells studied after the year 2005 had well-head failure rate of about 10% within the first year and rising to 40% likelihood of failure within the first 10 years, based on real world inspections of thousands of wells in Pennsylvania.

Response II-4-52: The EPA acknowledges comments regarding wellhead failure probability and the availability of parts needed for repair. The final rule allows delay of repair of fugitive emissions components due to unavailability of replacement components (or parts thereof) in certain circumstances at well sites, centralized production facilities, and compressor stations. Specifically, delay of repair is allowed if replacement is required but cannot be acquired and installed within the repair timeline due to either of the following conditions: (1) replacement valve supplies have been sufficiently stocked but are depleted at the time of repair; or (2) a replacement fugitive emissions component or a part thereof requires custom fabrication.

Comment: Commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) note EPA's proposal requires spacing consecutive quarterly OGI/Method 21 monitoring surveys at least 60 days apart. Due to safety issues and facility availability, 60 days is too restrictive. Further, requiring spacing inspections at least 30 days apart will allow for inspection across varying operating conditions. For these reasons, commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) request that EPA reduce the §60.5397b(g)(1)(iii)(F) OGI/Method 21 inspection survey spacing from 60 days to 30 days.

Commenter (2298-Pioneer Natural Resources USA, Inc.) recommends that EPA add language stating that the initial AVO inspection should begin between 30 and 60 days after the OGI inspection and to clarify that AVO be required only during the month no OGI inspection occurs. This will still ensure regular monitoring of facilities for leaks between OGI surveys; and an AVO conducted during the same month as an OGI would not help reduce emissions, but instead only be a record keeping burden.

Response II-4-53: The EPA disagrees that owners and operators subject to quarterly monitoring surveys should have the option to space the surveys 30 days apart (as opposed to 60 days). The minimum spacing between quarterly monitoring surveys of 60 days is being finalized to allow sources flexibility for improved scheduling of surveys and anything less than 60 days is too narrow of a window to ensure the quarterly monitoring requirements detect changes in emissions that can occur over time. 30 days from the previous survey could miss emissions that could have developed since the last survey and specifying 60 days accommodates for that without getting to

close to the next scheduled quarterly survey. This is in line with the spacing requirements for consecutive semiannual surveys that must be conducted at least 4 months apart and no more than 7 months apart.

For single wellhead only sites and small sites, the final rule specifies that the initial monitoring survey using AVO (or any other detection methods) must be conducted within 90 days of the startup of production. For multi-wellhead only well sites, well sites or centralized production facilities that contain the major production and processing equipment, the final rule specifies that the initial monitoring survey must be conducted using OGI or Method 21 within 90 days of the startup of production. For multi-wellhead only well sites, the final rule specifies that AVO must be conducted quarterly after the initial survey and OGI semiannually after the initial survey. For well sites or centralized production facilities that contain the major production and processing equipment, the final rule specifies that AVO must be conducted bimonthly following the initial survey and OGI quarterly following the initial survey. The EPA believe the timing for the different monitoring requirements with AVO and OGI is clear and no additional clarification is needed to specify that AVO be required only during the month no OGI inspection occurs. The EPA believes the rule as written ensures regular monitoring of facilities for leaks between OGI surveys.

Comment: Commenters (2172-KOGA, 2221-Texas Pipeline Association, 2270-Private Citizen, 2399-GPA Midstream Association, 2428-API) made various recommendations related to the delay of repair provisions. The recommendations are described below.

Commenters (2221-Texas Pipeline Association, 2270-Private Citizen) add shutdowns can occur for many different reasons, and a shutdown that is not scheduled for maintenance purposes can be a highly inappropriate occasion for conducting or completing repairs. Some planned shutdowns do not occur for maintenance reasons, last for a very short time, and are made on short notice. It would be unreasonable, and unworkable in practice, to require that repair personnel be mustered and repairs be made during these events. In addition, requiring complicated repairs to be made in these circumstances would disrupt normal operations more than would otherwise be the case and thus would disrupt production and transmission activities by delaying the unit's return to normal service. Similarly, it would be unreasonable to require repairs to be made where a leak was detected shortly before a scheduled shutdown, as it might not always be possible or feasible to locate appropriate repair personnel and/or parts in a timely manner given the short notice that would be involved. Again, requiring repairs to be completed during such a shutdown could greatly lengthen the shutdown, causing unnecessary disruption to natural gas supply.

Commenter (2221-Texas Pipeline Association) states it is appropriate for EPA to clarify that completion of delayed repairs is required during a scheduled shutdown where maintenance activities have been scheduled, not the next shutdown of any kind. This represents a reasonable accommodation of the issues expressed above and would align the oil and natural gas NSPS more closely to the delay-of-repair provisions in other NSPS, *e.g.*, Subpart VVa.<sup>122</sup>

Commenters (2172-KOGA, 2399-GPA Midstream Association) state the time required to order parts and make the repair should be at least 30 days in today's economy (with continuing supply

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<sup>122</sup> See, *e.g.*, 40 CFR § 60.482-9.

chain challenges) and with the expected increased demand associated with the new regulations. Should EPA finalize the rule, it should allow for 30 days to attempt a first repair of any leaking component detected through an AVO inspection. EPA should not be concerned about the repair being outstanding during the next scheduled AVO inspection. When moving to a frequency like monthly, it is unreasonable for EPA to assume there will not be overlap in surveys and repairs.

Commenter (2399-GPA Midstream Association) adds Colorado regulations require that a first attempt at the repair of a leaking component be made within five days if a site is located within 1,000 feet of an occupied area or within a disproportionately impacted community.<sup>123</sup>

Commenter (2428-API) requests that delay of repair requirements should be expanded. The commenter indicates that consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability. The commenter notes NSPS OOOO and OOOOa allow for delay of repair beyond a unit shutdown if “valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.”<sup>124</sup> In the Preamble to the November 2021 Proposal,<sup>125</sup> EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.

In addition, the commenter (2428-API) believes EPA should add other potential circumstances beyond an operator’s control that would require a delay of repair. Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Commenter (2428-API) suggests the following revisions to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

(3) Delay of repair will be allowed:

(i) If the repair is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, scheduled well shutdown, scheduled well shut-in, after a scheduled vent blowdown, or within 2 years, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel;

(ii) If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon

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<sup>123</sup> 5 Colo. Code Regs. §§ 1001-9:D.II.E.6.f-g, II.E.7.b (adopted Dec. 17, 2021).

<sup>124</sup> 40 CFR §60.482-9a(e).

<sup>125</sup> 86 FR 63174.

practicable, but no later than 30 days once the necessary replacement part supplies are available; or

(iii) If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.

Response II-4-54: Based on the comments received on delay of repairs provisions for well sites, centralized production facilities and compressor stations, the EPA is allowing delay of repair of fugitive emissions components due to unavailability of replacement components (or parts thereof) in certain circumstances. Specifically, delay of repair is allowed if replacement is required but cannot be acquired and installed within the repair timeline due to either of the following conditions: (1) replacement valve supplies have been sufficiently stocked but are depleted at the time of repair; or (2) a replacement fugitive emissions component or a part thereof requires custom fabrication. In either situation, the required replacement must be ordered within 10 calendar days after the first attempt at repair. The repair must be completed within 30 calendar days after receipt of the replacement or during the next scheduled shutdown for maintenance after the replacement is received (if the repair requires a shutdown). See section XI.A.2.b of the preamble to the final rule for EPA's reasons for allowing delay of repair under these specified conditions, other responses to the major comments on this issue, and additional details on this provision.

#### 4.1.3.10 Recordkeeping and Reporting

Comment: Commenters (1649-The Sisters of St. Francis of Philadelphia, 2152-California State Teachers' Retirement System (CALSTRS), 2185-New York State Common Retirement Fund (CRF), 2242-Seventh Generation Interfaith, Inc., 2285-Bailard, 2287-Climate Change and Environmental Justice, Interfaith Center on Corporate Responsibility (ICCR), 2424-As You Sow, 2455-Private Citizen, 2459-BMO Global Asset Management) ask for a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported methane emissions data, and enable them, as investors, to clearly differentiate between leaders and laggards. Commenter (1649-The Sisters of St. Francis of Philadelphia) adds plans must include deadlines and the local public should be informed as the EPA moves swiftly to finalize comprehensive standards.

Response II-4-55: The EPA generally agrees with the commenters. The final rule includes clear timelines affected facilities are required to comply with the emission standards, as well as the recordkeeping and reporting elements that are needed to ensure compliance with the rule.

Comment: Commenter (2393-Oklahoma Office of the Secretary of Energy and Environment) concurs with EPA's proposal to allow companies to develop a monitoring plan that covers multiple facilities rather than a separate plan for each site. This is not an endorsement of the entirety of the proposal, but a preference for this particular alternative.

Response II-4-56: The final rule specifies at §60.5397b(b) of the final rule that the fugitive emissions monitoring plan that covers all fugitive emissions components affected facilities must

be developed for each company-defined area. The EPA assumes that each company-defined area consists of 22 well sites.

Comment: Commenters (2168-INOGA, 2179-KIOGA, 2223-Texas Alliance of Energy Producers) believe reporting requirements for single wellhead well sites, small well sites, and small production sites should be minimized for the benefit of the small business operator. Single well sites which are visited monthly if not more often, and small well sites and small production sites that are visited daily and observed for leaks, should require no more than an annual report that might include estimated number of times visited and number of leaks identified. Training an operator's personnel is more important to identify, stop, report, and correct leaking components than to force operators to commit their resource's time and funding to burdensome compliance activities.

Response II-4-57The recordkeeping and reporting requirements in the rule that apply for each fugitive emissions affected facility, including single wellhead only well sites and small well sites, represent the minimum level of tracking and documentation necessary to ensure compliance with the rule. The final rule requires quarterly AVO inspections for single wellhead only well sites and small well sites, as proposed. Affected facilities are required to report annually the results of the quarterly AVO surveys, which would include key elements such as the dates the quarterly AVO surveys were performed, number and type of equipment for which leaks were identified, or, if no leaks were detected, a statement that there were no leaks on the day of inspection, information regarding the number and type of equipment for repairs occurred, and number and type of equipment with delayed repair. EPA emphasizes that recordkeeping and reporting are vital components of compliance assurance and believes the recordkeeping and reporting requirements established in the final rule are reasonable and appropriate.

Comment: Commenter (2325-Aclima) indicates that EPA's estimated annual per-well cost of complying with the rule is estimated to range from \$2,490 for biennial OGI monitoring to \$8,140 for monthly OGI monitoring at the average well site. Rolled up, that is between \$54,780 to \$179,080 per year for the average owner of 22 wells. Networked small sensor technologies can be implemented at a fraction of these costs, with the enhanced benefit of continuous, networked monitoring across all wells.

Commenter (2325-Aclima) notes that each well owner is also expected to develop their own monitoring plan, purchase a recordkeeping data management system specific to fugitive emissions monitoring and repair, and shoulder those upfront costs.

Commenter (2325-Aclima) states innovative cost-sharing data business models can meet the market needs, but this rule does not incentivize. Rather than unlock innovation across the industry, the rule as currently written may propagate siloization of data, non-standardized implementation, fragmented markets for solutions, and slow, bureaucratic reporting processes, further delaying the aggressive emissions reductions that are critically needed.

Commenter (2325-Aclima) provides the example, the rule speaks minimally to digital infrastructure, including cloud-based storage and database systems which enable novel analysis, visualization, and reporting of LDAR data. Such systems can facilitate rapid and automated operationalization of measurement data, as well as enable efficient reporting to regulators,



reduced friction of compliance, and sharing of best practices across the industry. The commenter urges the EPA to consider digital and standardized methods of reporting.

Response II-4-58: The EPA acknowledges the commenter's observations and suggestions for streamlining reporting. To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators submit electronic copies of performance test reports, semiannual reports, annual reports, and other notifications through the EPA's Central Data Exchange (CDX) using the CEDRI. For additional discussion on electronic reporting, see section X.N of the preamble to the final rule. In addition, the rule finalizes as proposed, that allow for the use of alternative test methods using advanced methane detection technologies for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and CVS used to route emissions to control devices. This provision will allow owners and operators to use multiple advanced technologies in combination, and facilitate the use of the most sensitive advanced technologies.

Comment: Commenter (2403-PAO) notes EPA states that owners and operators would be required to use the appropriate spreadsheet template to submit information to Compliance and Emissions Data Reporting Interface (CEDRI) for annual and semiannual reports. EPA states that a draft version of the proposed templates for these reports was included in the docket for this action. The EPA specifically requests comment on the content, layout, and overall design of the templates. The commenter indicates that it was not able to find this document. The commenter requests EPA make this document available for public review and comment.

Response II-4-59: The CEDRI reporting templates for the 60.5420(b) Annual Report and 60.5422(b) Semiannual Report for NSPS OOOOb and EG OOOOc were posted in the rulemaking docket for the December 2022 Supplemental Proposal prior to the start of the comment period. The document ID for the templates is EPA-HQ-OAR-2021-0317-1536.

#### 4.1.3.11 Other

Comment: Commenters (2308-National Stripper Well Association, 2403-PAO, 2446-IPAA) request that there be a pathway to less frequent monitoring for situations where emissions are declining or are when emissions are not detected.

Commenters (2308-National Stripper Well Association, 2446-IPAA) state if quarterly OGI is not identifying emissions issues that are not being found and addressed by the AVO component of the program, it needs to be revised to a semiannual requirement; if it adds no benefits as a semiannual program, it needs to be revised to an annual program or eliminated.

Commenter (2403-PAO) adds EPA should include a process whereby operators of existing facilities can reduce or cease monitoring if fugitive emissions monitoring results are not detecting emissions or there is little to no benefit.

Response II-4-60: The EPA disagrees that a reduced monitoring frequency is appropriate for situations where emissions potentially could be declining or not detected during a monitoring survey. The fugitive emissions monitoring requirements under NSPS OOOOb and EG OOOOc do not require the quantification of fugitive emissions; only the assurance that any fugitive emissions that are detected are properly repaired. Even if emissions quantification can be done

(or some other measure of performance such as recording the number of leaking components over time), the EPA believes the burden associated with tracking emissions and varying compliance requirements would be a burdensome and complex undertaking. Further, even if no emissions are detected during a fugitive emissions monitoring survey, it does not eliminate the possibility that emissions could be present in the future as emissions can occur at any time, and fugitive emissions are likely to increase as equipment ages. Requiring less frequent monitoring could lead to fugitive emissions being undetected longer. Therefore, the EPA is finalizing a fugitive emissions components fixed monitoring frequency program with no change due to leak rate performance. Comment: Commenter (2347-Clarke Valve) supports proposed regulations that are as stringent as practicable and technologically feasible, *e.g.*, using the BSER. One study provides examples of major available methane mitigation, or abatement, technologies and measures for the oil and gas sector “that are specified in at least one assessment” as follows:<sup>126</sup>

“[u]pstream leak detection and replacement\*, replacing pumps\*, replacing with instrument air systems\*, vapour recovery units\*, blowdown capture\*, replace with electric motor, early replacement of devices, replace compressor seal or rod, install flares, install plunger, downstream leak detection and replacement.”

(\* indicates sometimes can be implemented at no net cost).<sup>127</sup>

Commenter (2347-Clarke Valve) adds the same report indicates that rapid deployment of such available, cost-effective abatement technologies and measures alone could reduce methane emissions by nearly 25 percent below anticipated levels by 2030, with the oil and gas sector dominating this avoided warming potential.<sup>128</sup>

Commenter (2347-Clarke Valve) believes that EPA’s proposals to use 500 ppm as the defined leak detection limit is problematic. Legacy globe control valves are highly prone to leaks. In addition, EPA’s decision to not require replacement of leaking equipment with “low-emitting” (“low-e”), respectfully, is flawed. According to the commenter, while a legacy globe control valve may be rated at 500 ppm for fugitive emissions when “new” or “recently adjusted,” the actual leakage between adjustments can be as high as 200,000 ppm (or 20 percent of the flow volume in the pipe). This is a particular problem at remote sites and for marginal wells that are not constantly monitored. The main technical problem with wound graphite packing, which is currently used in all legacy globe control valves, whether a manufacturer markets them as “low-e” or not, is that, like a wind-up watch, a globe control valve’s graphite packing gradually begins to unwind itself, immediately after having been adjusted. If left to unwind for a long enough time, the leakage could be many times greater than manufacturers’ claims. It is unrealistic to expect that millions of globe control valves in the field with wound graphite packing will always be properly adjusted. Even “low-e” valves use graphite packing which will unwind and, hence, will regularly exceed their factory rating of 100 ppm between adjustments.

Commenter (2347-Clarke Valve) states several manufacturers of non-globe type control valves use non-graphite packing, which do not require adjustments. Legacy globe control valve

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<sup>126</sup> Ilissa B. Ocko, et al.. Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming. (2021) Environ. Res. Lett. 16 054042 (Ocko, et al., 2021).

<sup>127</sup> Ocko, et al. (2021).

<sup>128</sup> Ocko, et. al. (2021).

manufacturers should be required to utilize similar solutions. One way to achieve this is to impose a ban on graphite packing for any valves used in methane applications. While the commenter is aware that EPA considers 500 ppm a reasonable limit, this does not account for the leakage between adjustment intervals, particularly at remote sites or marginal wells, which may rarely or never be adjusted after installation.

Commenter (2347-Clarke Valve) argues significant scientific and material advances have been available for the last few decades that easily allow manufacturers to meet a more stringent standard. In fact, several valve manufacturers already are using widely-available, mature seal technology, such that their valves are achieving emissions below 50 ppm even after 100,000 cycles, which equates to 10 years of simulated use. High grade seals that enable valves to achieve emissions of 50 ppm or less typically cost less than \$5.00 each.

Commenter (2347-Clarke Valve) concludes thus, the leak detection limit should be adjusted, *i.e.*, lowered, or made more stringent, to 50 ppm. Some EPA Consent Decrees already rely on a 100 ppm corrective action leak detection limit. Increasing the stringency of the leak detection limit also would reflect an acknowledgement of the availability and cost effectiveness of technologies that can reduce or virtually eliminate fugitive emissions and the need for fewer (if any) repairs, which, in turn, would enable semiannual and quarterly monitoring to suffice.

Commenter (2347-Clarke Valve) encourages EPA to require oil and gas operators to measure emissions at a site or on a piece of equipment immediately prior to any adjustments or repairs being made. Having “before” and “after” emissions levels will facilitate a comparison of emissions levels, an assessment of whether intended emissions reductions actually have been obtained, and whether any additional modifications might be needed. Doing so still does not necessarily capture the duration of a leak or extent of excess methane emitted, but it is a step and will reflect a snapshot in time.

Commenter (2347-Clarke Valve) supports EPA’s plans to allow/require monitoring using LDAR for certain types of equipment/operations. However, it is worth considering that adjustments to certain types of equipment do not necessarily constitute “repairs,” because the modifications often are quite temporary.

Response II-4-61: The EPA agrees with the commenter that lower-emitting technologies can help to lower the frequency of leaks from fugitive emission components. However, they cannot necessarily prevent them from happening. Therefore, the EPA maintains that an effective fugitive emissions monitoring and repair program must include routine monitoring. As noted by the commenters, replacing equipment components with low-e components can be cost-effective solution in some applications, but that depends on the size, operational characteristics, and expected service life of the equipment. For many production sites, the expected service life of a well may not warrant additional cost of low-e equipment. The EPA also has limited data on the failure rates of different low-e technologies, so it is difficult to quantify the cost and emission reductions associated with a requirement to use low-e components. As such, the EPA could not determine use of low-e equipment for BSER. However, the EPA recognizes that selecting low-e equipment can help to reduce emissions, so we sought to promote its use to the extent practical. For natural gas plants, for example, EPA included reduced monitoring requirements when low-e equipment are used. The EPA will continue to collect information on the cost and performance of low-e equipment to further assess these technologies in future rulemakings.

Comment: Commenters (2251-National Association of Manufacturers (NAM)), 2429-Wyoming Outdoor Council) urge EPA to allow advanced technologies as alternatives to OGI.

Commenter (2251-NAM) specifically suggests if a methane leak is a process emission and the production operator is operating within its permitted levels that EPA not require OGI. The commenter recommends that companies be given the option to use alternative technology.

Commenter (2429-Wyoming Outdoor Council) asserts EPA should allow advanced technologies to be used for LDAR, if they are shown to deliver equal or better emissions reductions. Based on Wyoming's experience in the Upper Green River Basin, the commenter thinks operator flexibility (within reason) is critical for the EPA to codify into the final rules. This is key to encouraging private sector innovation, incentivizing operators to invest in new technologies that can benefit the broader oil and gas industry, and growing Wyoming's methane regulation economy. It is also important that EPA help facilitate experimentation with new technologies so their development will be accelerated. Industry experience in our region suggests that the cost of implementing these technologies drops significantly over time, with one prominent Wyoming-based company in particular reporting a 75 percent reduction in the cost of LDAR over five years of implementation.<sup>129</sup>

Response II-4-62: EPA has provided a pathway for use of advanced technologies in NSPS OOOOb and EG OOOOc. See Volume II, Chapter 5, and discussion in section X.B of the preamble to the final rule for information on advanced technologies.

#### **4.1.4 Modeling**

Comment: Commenter (2333-LongPath) agrees with the blind test verification of the functioning of alternative technologies. However, the commenter believes that the same criteria should apply to verify the efficacy of OGI surveys, EPA Method 21 surveys, and AVO surveys. The commenter notes that EPA's language suggests that an "adequate demonstration" is required of BSER and AVO forms a substantial portion of the BSER in the supplemental proposal; yet, while EPA conducted an extensive literature review on the range of performance and limitations of OGI, as well as commissioning multiple laboratory studies and OGI technology evaluations, the commenter is not aware of a body of literature or comprehensive testing and evaluation of AVO. Further, they add that AVO performance specifications are parameterized in the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model; and AVO inspections are given a 0 percent chance of failure for any leak above a very small leak rate, despite this number never having been tested or proven at any scale. The commenter also provides as part of their comment, a case study demonstration of the inability for AVO to identify even very sizeable leaks.

The commenter (2333-LongPath) believes that if EPA is to define AVO as all or part of BSER, it will be necessary for blinded studies and field tests to be performed across a range of operator experience levels, complexity of equipment and sites, leak types (including aperture size, height

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<sup>129</sup> EDF Factsheet: Finding, fixing leaks is a cost-effective way to cut oil and gas methane emissions. Available at: [https://www.edf.org/sites/default/files/content/ldar\\_fact\\_sheet\\_updated\\_with\\_citations.pdf](https://www.edf.org/sites/default/files/content/ldar_fact_sheet_updated_with_citations.pdf).

above ground level and flow rate), and ambient conditions (wind, rain, snow, and against the substantial noise volumes on large production sites in, for example, the Permian basin). According to the commenter, until such time as demonstrable support for AVO as BSER, the FEAST models should not include any emissions reduction from AVO, as there is no supportable evidence of its efficacy.

The commenter (2333-LongPath) also notes that the gold standard for testing and quality assurance that will be applied to alternative technologies is objective third-party blind testing. The commenter suggests that the requirement for boot-strapping experience levels, by having senior OGI operators audit junior OGI operators, runs the risk of cross-organizational problems with OGI accuracy and does not meet this same standard.

Response II-4-63: First, the EPA provides specific requirements for testing and verifying the OGI instrument can detect a defined hydrocarbon release within NSPS OOOOb. Similarly, EPA Method 21 includes very specific instrument specifications and quality control requirements to ensure that these instruments are operating as intended. As such, the EPA finds no need to require further third-party verification of these methods. For the alternative technologies, the EPA does not have specific procedural and quality assurance methods as the purpose of the alternative technology provisions are to allow the use of additional technologies without having to define test methods and QA procedures within the rule for each of these technologies. Thus, for the alternative technologies, a blind test verification is needed to determine the detection level of the method (key parameter used to assess the alternative technology).

The EPA acknowledges that the AVO inspections have much less well-defined quality assurance specifications compared with the OGI and EPA Method 21 leak inspections or “instrument monitoring methods.” For these reasons, the EPA considered the instrument monitoring methods first when determining BSER. The EPA notes that the FEAST modeling conducted for AVO, we used higher detection limits and used a 90 percent maximum probability of detecting leaks at the high-end of the leak spectrum, so we anticipated that AVO inspections would not be as effective as the instrument monitoring methods. Nonetheless, EPA found that additional AVO inspections could result in cost effective additional emission reductions. However, EPA did not include any emission reductions from AVO when developing the alternative technology equivalency matrix. As such, the final equivalency matrix is based on the emission reductions projected considering the instrument monitoring methods that have specified quality assurance approaches. In this manner, we consider we have similar quality of data between the instrument monitoring methods and alternative technologies that must establish detection limits based on blind test verifications.

Comment: Commenters (2286-CDPHE, 2333-LongPath) question the effectiveness of AVO used in FEAST modeling for the December 2022 Supplemental Proposal.

Commenter (2286-CDPHE) notes that in evaluating the annual costs of an LDAR program, EPA incorporated the results of FEAST modeling to include the modeled number of components identified as leaking, assuming an average of 0.62, 1.25, and 3.7 leaks requiring repair found annually at single wellhead only and small well sites, multi-wellhead only well sites, and well sites and centralized production facilities, respectively. EPA explained that the dataset included all leaks measured across numerous studies. The commenter highlights the many years of LDAR

data collected in Colorado since Colorado's adoption of a regulatory LDAR program in 2014.<sup>130</sup> Colorado's data shows both different annual rates for leaks requiring repair<sup>131</sup> as well as the few leaks requiring repair as detected by AVO.<sup>132</sup> The difference in the data collected under Colorado's well established LDAR program as compared to EPA's estimated model plant values and the differences between Colorado's applicability provisions (*e.g.*, well production facilities with estimated uncontrolled actual VOC emissions from the highest emitting storage tank >12 and <50) and EPA's defined facilities (*e.g.*, single wellhead only well site) further highlights the need to provide flexibility for states in comparing existing and effective state programs to EPA's model EG. The commenter also reiterates that EPA should permit states to use VOC emissions as a proxy for comparing the stringency of a state program with EPA's proposed thresholds.

Commenter (2286-CDPHE) invites EPA to review the annual LDAR reporting analyses of operator reported data for all LDAR completed as required under Colorado's Regulation Number 7. These analyses represent real world data submitted by operators on an annual basis. The LDAR reporting and analyses emphasizes the efficacy of OGI detection, and the disparity in detection between AVO and the advanced monitoring technology.

Commenter (2333-LongPath) points to the academic literature's lack of studies on the efficacy of AVO inspections for: emissions with variable rates, intermittent emissions, emissions elevated above ground level, emission point aperture sizes, and emissions occurring in varying ambient conditions (*e.g.*, wind, rain, and other ambient equipment/process/compressor noise that may obstruct detection). The commenter therefore recommends that EPA perform or seek out studies of AVO effectiveness across this range of conditions before incorporating it into the FEAST model for calculation of emissions reductions for purposes of equivalency demonstration for alternative monitoring solutions. For example, continuous monitoring is known to have higher effectiveness for emissions detection and mitigation than AVO (see joint comment from Dan Zimmerle, Stefan Bokaemper and Caroline Alden, as well as Appendix B of the commenter's attachment).

Commenter (2333-LongPath) adds for larger sites, the commenter has mitigated emissions from process malfunctions on production equipment that were not identified with AVO. For example, some types of malfunctions can result in emissions from tank equipment with wide-aperture release points. This combination of factors: methane emissions spread across multiple, wide-aperture emission points means that audial, visual, and olfactory senses may be unlikely to identify a problem.

Response II-4-64: With respect to AVO effectiveness, the EPA did use an upper level of detection of 90 percent for AVO monitoring. The EPA acknowledges that the level of detection for AVO will be more variable than OGI because leaks detected by olfactory methods (smell) will largely rely on other constituents present in the natural gas. However, the modeling runs

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<sup>130</sup> See Colorado's Leak Detection and Repair (LDAR) Annual Reports at <https://cdphe.colorado.gov/oil-and-gas-and-your-health/oil-gas-compliance-and-recordkeeping>.

<sup>131</sup> See Colorado's 2021 LDAR Annual Report, *e.g.*, in 2021, (a) 1,384 leaks requiring repair were detected during 2,790 semi-annual OGI inspections, resulting in an annual rate of 1 leak requiring repair per facility, and (b) 3,668 leaks requiring repair were detected during 9,187 monthly OGI inspections, resulting in an annual rate of 4.8 leaks requiring repair per facility.

<sup>132</sup> See Colorado's 2021 LDAR Annual Report, *e.g.*, in 2021, only 1,546 leaks were detected during 564,427 AVO inspections.

when using AVO alone provided reasonable agreement to the emissions from oil and gas production sites that rely primarily on AVO inspections as reported in the DOE study data.<sup>133</sup> Therefore, the EPA concluded that the modeling assumptions regarding the effectiveness of AVO monitoring were reasonable.

Comment: Commenters (2393-Oklahoma Office of the Secretary of Energy and Environment (OSEE), 2446-IPAA) are not in a position, at this point, to opine on EPA's use of FEAST modeling to demonstrate equivalency with the statutory requirement of BSER. The commenter encourages EPA to continue to consider/accept other models. Consistent with the Oil and Gas Industry's position that EPA should not regulatory lock in a particular technology, like OGI, EPA should retain flexibility to encourage innovation. Commenter (2446-IPAA) recommends EPA also consider whether additional combinations of detection limits and sample frequency detections can enable a broader range of technologies if they can demonstrate equivalency to EPA's determined BSER. For example, EPA could include additional frequencies and combinations of technologies to encourage the deployment of technologies that can demonstrate equivalency with BSER.

Response II-4-65: The EPA is finalizing a fugitive emissions monitoring approach for well sites and centralized production facilities that establishes the monitoring frequency and detection method (AVO and/or OGI) based on results obtained from using FEAST, as discussed in the December 2022 Supplemental Proposal. As previously acknowledged, although the EPA relied on FEAST to model the various programs, EPA expects other available modeling simulation tools to produce similar results.

The final rule includes technology flexibility and does not stipulate a specific technology under the advanced methane detection technology program. Owners and operators have the ability to use a combination of technologies that align with the minimum screening frequencies and minimum detection threshold of screening technology detection thresholds specified in the matrix in the final rule.

Additionally, see Volume II, Chapter 5 for more responses related to alternative technologies and sections X.B.1 and XI.B.1 of the preamble to the final rule for discussion on the final standards related to periodic screening using advanced methane detection technologies and development of the screening matrices.

Comment: Commenter (2446-IPAA) notes that EPA creates three model facilities with detailed component count elements and uses emissions assumptions and emissions simulations using FEAST to create various control technology options. Essentially, EPA produces FEAST based on emissions levels related to throughput – 1% or 0.5% of throughput. For its single wellhead only well site, its multiple wellhead only well site, and its small well site facilities, the production level would be below the threshold of EPA's earlier definition of a low production well. For its large facility, the production level would be three times the level of a low production well. It is because of these assumptions that the model is really more pertinent to the EG since no producer would be planning to drill new wells with these levels of production.

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<sup>133</sup> Memorandum from Jeff Coburn, RTI International. *Summary of Additional FEAST Modeling Runs*. April 24, 2023.

Commenter (2446-IPAA) states EPA used two resources to justify the validity of its FEAST results – the DOE Study and the Rutherford Study. If EPA had relied on the DOE Study’s actual data for low production wells for the single well site, multiple well site, and small well site analyses, it would need to shift its FEAST inputs. As EPA describes in its materials, the DOE study would have produced the following differences: [Table shows EPA FEAST Emissions – 0.5% Leak Generation and the DOE Study – As Reported by EPA for a single, multiple, or small wells site. The EPA FEAST Emissions had higher estimations for all well sites.]

Commenter (2446-IPAA) disagrees with commenter (2433-EDF et al), stating there is no reason why EPA should use the Rutherford Study as a data source. The genesis of the Rutherford Study relates to the ongoing disputes of differences in studies and inventories, such as the Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHGI"), which is bottom-up calculations and atmospheric studies. The Rutherford Study seeks to close the gaps by addressing the emissions factors used in the GHGI. It turns to the array of other studies and effectively cherry picks emissions factors from those studies to replace ones in the GHGI. Inherent in this effort is reliance on the same studies that have been used for prior analyses. The commenter has addressed the shortcomings of these studies in past comments – limited sampling times, little or no information on the facility operation, and no certainty on quality control of the data. And, as in past situations, these reports only incidentally take data on the low production wells that are the focus of EPA's analysis. Finally, the Rutherford Study brings no new data to the analysis; it merely regurgitates old, inadequate material.

Commenter (2446-IPAA) states the DOE provides new information with emissions data taken and with facility information at the time of the sampling. The issues with the DOE Study relate to EPA's interpretation. The DOE Study provides substantial new information on the emissions profile of low production wells, but EPA has chosen to limit the use of this material.

Commenter (2446-IPAA) provides an example, with its inordinate focus on component counts as the sole basis to regulate fugitive emissions, EPA immediately discounts how the DOE Study can be used to create a much simpler regulatory path. At this point, it is pertinent to bring into the discussion the use of AVO monitoring for fugitive emissions at oil and natural gas production sites. The commenter has supported the use of AVO monitoring as an alternative to the costly OGI and Method 21 LDAR that have been the primary basis for previous fugitive emissions programs. The commenter supports EPA's decision to embrace AVO in its regulatory framework. It is particularly significant for low production wells. Consequently, in assessing the material in the DOE Study, evaluating the emissions information in a post-AVO application context is imperative. That is, while there may be higher emitting components at a facility, in looking at how to assess regulatory options, those that would be eliminated by an AVO program should be excluded. (Similarly, if the higher emitting component is regulated under a part of EG OOOOc that is separate from the fugitive emissions program, it should be excluded.) The DOE Study demonstrated that low production well sites significant emissions resulted from predictable sources – tank vents or thief hatches, pneumatic controllers at separator vessels, open valves, or damaged piping. All of these can be identified with AVO. This reality is particularly clear for well sites producing 6 BOED or less. Compared to the complicated matrix of well site options in the EPA proposal, this approach would be easily identifiable. Moreover, it would mean that 83 percent of the regulatory burden on low production wells would be managed in a straightforward program.



Commenter (2446-IPAA) notes while EPA continues to believe that component count approaches should define its various regulatory matrices, its regulatory analysis is based on use of FEAST. The commenter lacks the resources to duplicate the EPA FEAST analyses or conduct an independent analysis of the model, but at this point the commenter supports the use of the model and encourages EPA to utilize other models and accept additional modeling results produced after the close of the comment period.

Response II-4-66: As discussed in the December 2022 Supplemental Proposal preamble and noted by the commenter, EPA estimated the fugitive emissions under different monitoring scenarios at well sites uses a FEAST modeling approach. The modeling uses built-in emissions data from various emissions measurement campaigns which were supplemented with additional study data to provide an empirical emissions dataset for the model simulations. The EPA acknowledges the commenter's input regarding the Rutherford, *et al.*, study.

The emissions data used in the FEAST model included data from direct measurement campaigns. Despite some shortcomings of the data in studies analyzed in the Rutherford, *et al.*, study, the study is useful because it analyzes and reconciles multiple sources of data and multiple methods of estimating emissions to arrive at a more robust and validated model of component-level emissions from well sites. The EPA chose to use the Rutherford, *et al.*, study and the U.S. DOE marginal well study to help inform assumptions necessary to establish a baseline emissions scenario in the FEAST model because they represent credible compilations of relevant emissions data at the well site level. The set-up of the FEAST model was further validated by finding that the results generated by FEAST regarding the effectiveness of different OGI monitoring frequencies align well with other values reported in literature. The EPA found that the FEAST results align with the EPA's historical assumptions of 40, 60, and 80 percent, for annual, semiannual, and quarterly OGI monitoring, respectively,<sup>134</sup> and these percent efficiencies compare well to those discussed in the TSD for the 2020 Technical Rule.<sup>135</sup>

EPA disagrees with the commenter's characterization that that EPA placed an inordinate focus on component counts as the sole basis to regulate fugitive emissions. This is not true and EPA and although EPA has noted that the U.S. DOE marginal well study concludes that the frequency and magnitude of emissions from well sites are more strongly correlated with equipment counts than with production rates, this is not the solely basis for the fugitive emissions monitoring structure, which is also based on the equipment located at the well site, importantly, leak-prone equipment known to emit large emissions.

Comment: Several commenters (2286-CDPHE, 2387-Energy Institute, Colorado State University) provide feedback on EPA's FEAST modeling.

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<sup>134</sup> Specifically, for large well sites at a 0.5 percent leak generation rate, FEAST estimates reductions of 47, 67, and 78 percent, for annual, semiannual, and quarterly monitoring, respectively. For multi-wellhead only well sites at a 0.5 percent leak generation rate, FEAST estimates reductions of 44, 67, and 78 percent, for annual, semiannual, and quarterly monitoring, respectively. For single wellhead only well sites, FEAST estimates reductions of 48, 68, and 77 percent, for annual, semiannual, and quarterly monitoring, respectively.

<sup>135</sup> See section 2.4.1 of "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa." August 2020. EPA-HQ-OAR-2017-0483-2290.

Commenter (2286-CDPHE) concurs with EPA's statement that while EPA used FEAST, EPA expects that other modeling simulation tools would produce similar results. Through the commenter's alternative Approved Instrument Monitoring Method (AIMM) application process, commenter has evaluated applicants' use of both FEAST and the Leak Detection and Repair Simulator (LDAR-Sim). Colorado is also involved in discussions around the development of the Methane Emissions Estimation Tool (MEET). The commenter agrees that determining the appropriate inputs and assumptions in the models is very important, but notes the importance of providing flexibility to technology developers and owners and operators to evaluate the use of alternative monitoring technologies and systems, such as through a variety of tested modeling tools, controlled testing, and/or field testing.

Commenter (2387-Energy Institute, Colorado State University) states EPA should implement representative intermittency in modeling, including the current FEAST model.

Response II-4-67: The EPA acknowledges the commenters input regarding available modeling tools, recommendations for proper inputs to the FEAST model EPA used, and other modeling related comments.

Under the advanced methane detection work practices of the final rule, flexibility in selecting the appropriate advanced methane detection technology is included while ensuring that the alternative standard achieves equivalent or greater efficacy in detecting and reducing methane emissions compared to the use of ground-based OGI surveys, EPA Method 21, and AVO inspections.

With respect to the recommendation to include intermittency in the model, the EPA first notes that intermittency is largely reported with respect to super-emitters. Traditional equipment leaks, like those modeled for fugitive emission components in the BSER analysis are much less prone to intermittency. While some intermittency may occur, the EPA expects that very few of the fugitive emission components will have intermittent emissions, so the inclusion of intermittency is not expected to appreciably impact the BSER determination. Second, the EPA has limited data by which to model intermittency, especially for the more traditional fugitive emission components. To model intermittent emissions, assumptions would have to be made regarding the fraction of leaks that exhibit intermittent behavior and the typical duration of emissions when they are leaking. This information is not available for the fugitive emission components modeled in the BSER analysis. The EPA attributes the limited availability of data regarding intermittency of smaller but more common leaks to the scarcity of intermittent behavior for this class of fugitive emission components and the limited impact of intermittency on the emissions from these traditional fugitive emission components.

Comment: Commenter (2353-CrownQuest Operating, LLC.) notes EPA's FEAST models mistakenly use notably high numbers (1.0% and 0.5%) for leak prevalence (the percentage of components found emitting fugitive emissions during inspections). At first, these figures appear conservative compared to the numbers produced from the Closing the methane gap study referenced by the EPA. Closing the methane gap found a leak frequency of 1.3% using a dataset of 3700 measurements, many of which are from before OOOOa regulation in 2015.

Commenter (2353-CrownQuest Operating, LLC.) states the data the EPA uses as the foundation for its models is from a small and old sample set. The referenced study is not the newest data or a

representative sample group, which skews the sensitive numbers used by EPA to feed their models. The EPA has access to better data. The EPA has millions of component surveys recorded from over seven years of OOOOa regulatory inspections. This data would represent a much larger dataset and newer data than used here, but the EPA chooses not to use it.

Commenter (2353-CrownQuest Operating, LLC.) argues an even better option for quality data is The Environmental Partnership. The Environment Partnership has conducted millions of measurements in the last several years following EPA LDAR inspection regulations. This dataset shows a leak frequency of only 0.08% across millions of OGI surveys conducted within the last several years, which is less than one-sixth of the lowest number used by the EPA to feed a very input-sensitive model. The EPA should use one of these better data sources if it plans to use FEAST models to justify regulation.

Response II-4-68 In the December 2022 Supplemental Proposal, the EPA discussed how it evaluated different leak generation rates for each well site model plant.<sup>136</sup> The EPA modeled AVO and OGI programs at two leak generation rates (1.0 percent and 0.5 percent) to compare the resulting baseline methane emissions against empirical emissions data and identify which model results more closely reflect real-world emissions measurement campaign results. As discussed, EPA's analysis indicated that 0.5 percent leak generation rate was more likely to be representative of the actual average emissions from single wellhead only well sites, small well sites, and multi-wellhead only well sites, based on comparing FEAST modeling results to the average of the U.S. DOE marginal well study and the Rutherford, *et al.*, study. The same conclusion was reached for well sites with major production and processing equipment and centralized production facilities, i.e., a leak generation rate of 0.5 percent appeared to be most representative of real-world emissions from these sources. The sources used to evaluate FEAST modeling results at different leak detection rates are documented credible empirical studies. The final rule establishes a fugitive emissions monitoring program based on the evaluation of a 0.5 percent leak detection generation rate, proven to be appropriate for consideration of the costs of control and appropriate monitoring frequency at all well sites.

#### **4.1.5 Costs/Resources Needed**

Comment: Commenters (2168-INOGA, 2179-KIOGA, 2205-Kriebel Well Services, Inc., 2257-MOGA, 2279-U.S. Small Business Administration, 2308-National Stripper Well Association, 2325-Aclima, 2353-CrownQuest Operating, LLC.) state small entities remain concerned about the cost of OGI requirements and their ability to procure the services of OGI contractors, particularly within the timeframes that EPA's proposal would require.

Commenter (2168-INOGA) states because of the size of a single wellhead well site, particularly those found in the Illinois Basins constructed of less than 120 total components (including fewer than 25 valves), an AVO survey in proximity of the wellhead and associated equipment by the operations team allows for discovery of most gas leaks. The natural composition of the gas in this basin is distinctive, without any additives. Small leaks allow can be identified by an untrained person through their olfactory sense.

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<sup>136</sup> 87 FR 74729-74739.

Commenters (2168-INOGA, 2172-KOGA) add the small production sites, typical of the legacy gas producing properties of the Illinois Basins often include small compressors and dehydrators and possibly an un-controlled tank but are plumbed together with a minimal number of components and valves. OGI survey requirements for these small sites are unnecessary and a financial and reporting burden on their operator.

Commenter (2439-State of Michigan Department of Environment, Great Lakes and Energy) states the EPA attempts to rationalize the cost of conducting OGI inspections by providing their estimate on what an OGI inspection will cost, however, it seems the EPA's estimates of cost may vary significantly between states. The cost of conducting AVO inspections and reasonable reporting frequency may be as protective, and more economic at existing marginal wells since inspections can be completed during normal business operations and would not require any specialized equipment or travel expenses. Further, production levels could be reconsidered as a basis for consideration of different fugitive emission requirements if one is mindful of the impact these proposed rules will have on small businesses.

Commenters (2205-Kriebel Well Services, Inc., 2308-National Stripper Well Association) state an OGI camera alone costs approximately \$100,000. Some low production well operators may need to purchase more than one to cover the proposed LOAR requirement. Another option for producers would be to hire a consultant, but this becomes costly as well. Consultants charge anywhere from \$500 to \$1,000 to perform OGI to meet the proposed LOAR requirement. Low production well operators with 500 plus wells would conceivably have to budget \$1,000,000+ annually. Commenter (2308-National Stripper Well Association) adds building new reporting systems is expensive and would come with additional increases in payroll costs as new employees would be needed to process all of the required documentation. This will drive these small businesses out of business!

Commenter (2179-KIOGA) cites the independent oil and gas industry should not be burdened with purchasing and learning how to operate an OGI device costing approximately \$90,000 to comply with the fugitive emissions requirements at wellhead only sites. The EPA did not evaluate the cost for these small entities to comply with the proposed EGs; therefore, they should be excluded from applicability.

Commenter (2446-IPAA) states when EPA undertakes its cost-effectiveness analysis for its OGI based proposal, it again assesses the use of AVO as an addition to an OGI program. While this may be appropriate for truly large well sites, a more appropriate analysis for those sites on the borderline between small well sites and large wells would be the initial application of the small well site AVO program followed by the addition of an OGI requirement. This is particularly important because the shift between the requirements is from an all AVO quarterly program to a bimonthly AVO and quarterly OGI program – a fourfold cost increase. A more logical approach would be to move from an AVO small well program to an AVO/OGI mixed program for an intermediate well site to its AVO/OGI program for large sites.

Response II-4-69: The EPA agrees AVO inspections for fugitive emissions monitoring for single wellhead only well sites and small well sites are appropriate. This approach has been retained in the final rule. The specific requirements being finalized for single wellhead only well sites and small well sites are described in section X.A.1.a.ii of the preamble to the final rule for new

sources under NSPS OOOOb and in section X.A.1.b.ii of the preamble to the final rule for existing sources under EG OOOOc.

The EPA did consider the impact of the fugitive emissions monitoring requirements on small businesses in general (*i.e.*, requirements that affect small operators at new and existing sites). This was a factor in determining that for single wellhead only well sites and small well sites, quarterly AVO surveys were appropriate. Inspections using AVO do not require specialized equipment or operator training but does allow the identification of large leaks. In addition, AVO monitoring can easily be built into regular maintenance activities that are designed to keep the equipment at the site in good working order. The EPA is also including final requirements which allow AVO and soap bubble tests as an option for finding fugitive emissions, particularly because they are low cost and easy to implement alternatives for detecting leaks. The EPA believes this will particularly benefit small entities because AVO surveys at these types of well sites are effective at identifying the types of large emissions from sources located at these well sites at a much lower cost than OGI surveys. As shown in Table 10 of the December 2022 Supplemental Proposal, the cost of quarterly AVO inspections at single wellhead only well sites and small well sites were estimated at \$660 per year per site with a cost-effectiveness of less than \$1,200 per ton of methane reduced, which EPA found to be reasonable.

#### **4.1.6 Well Closure Requirements**

##### **4.1.6.1 General Support/Opposition**

Comment: Commenters (1633-Natural Resources Defense Council (NRDC), 1643-Ohio River Valley Institute (ORVI), 1649-The Sisters of St. Francis of Philadelphia, 2156-Catholic Charities of Gallup Diocese, 2163-EOS at Federated Hermes, Ute Indian Tribe-2177, 2181-Ute Indian Tribe of the Uintah and Ouray Reservation, 2201-West Virginia Highlands Conservancy, 2209-Public Land Solutions, 2212-On behalf of the Union of Concerned Scientists, 2215-West Virginia Rivers Coalition et al., 2217-Religious Action Center of Reform Judaism, 2315-New York State Department of Environmental Conservation (NY DEC), 2236-Physicians for Social Responsibility Pennsylvania (PSR), 2271-Private Citizen, 2303-NTAA, 2310-Montana Department of Environmental Quality (DEQ), 2352-Environment Texas Research and Policy Center, 2392-Earthjustice et al., 2394-Earthworks, 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al., 2429-Wyoming Outdoor Council, 2433-EDF et al, 2448-Project Canary, PBC, 2456-Hal Schmid, 2883-US Senator Martin Heinrich et al., 3705-Breathe Easy Susquehanna County) support the proposed rule requirement to monitor abandoned and unplugged wells until all wells have been plugged and equipment removed and require owners to be responsible for all necessary closure plans, financial assurance, and post closure surveying as well as repairs if emissions are detected post closure.

Commenter (1643-ORVI) notes a recent report by the PA DEP found that more than half the conventional oil and gas well operators in the state never report production data and that they have issues over 3,000 violations to “Failure to plug a well upon abandoning it” over the last five years. The report also found that 59% of conventional well operators failed to report mechanical integrity of their wells which means they are not making sure their oil and gas wells are not leaking fluids into groundwater or surface water or natural gas into the air or operating their wells safely.

Commenter (1643-ORVI) states despite producing just 7% of oil and gas in in the four-state Ohio River Valley region, which includes Kentucky, Ohio, Pennsylvania, and West Virginia, low producing stripper wells make up 90% of active wells. The state of WV – because it has so few inspectors, just 9, or one inspector for every 13,000 wells – hardly issues any violations. In 2018, they only inspected 13 abandoned wells and issued 80 notices of violation. Meanwhile, PA DEP issued over 6,000 in 2018 or 75 times the amount in WV despite having just twice as many wells.

Commenters (2201-West Virginia Highlands Conservancy, 2392-Earthjustice et al., 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al.) appreciate EPA’s acknowledgement that emissions from idle wells are, in some cases, “very large,”<sup>137</sup> and EPA’s proposal for monitoring until no emissions are detected by OGI.

Commenter (2408-Colorado Local Government Coalition) adds in Colorado operators must continue to conduct LDAR inspections at shut-in wells provided such wells remain under pressure.<sup>138</sup> In addition, Colorado requires operators conduct Bradenhead monitoring and testing on a monthly basis for wells an operator intends to plug and abandon, as indicated by inclusion on an operator’s out-of-service list, until the operator plugs and abandons the well.<sup>139</sup> Operators must also conduct an AVO or other inspection of each out of service well annually to confirm integrity of the wellhead.<sup>140</sup> New Mexico requires annual Method 21 or OGI inspections at idle wells, beginning 30 days after a well is placed into idle status.<sup>141</sup>

Commenter (2201-West Virginia Highlands Conservancy) agrees with the EPA that idled and unplugged wells can be large sources of emissions. In West Virginia this is certainly true. In West Virginia the number of idled and unplugged wells dwarfs the number of active and producing wells. The commenter strongly supports the requirements to conduct a final monitoring survey using OGI. There are legions of well sites in West Virginia that have never been properly closed. In order to make this rule effective, all of those sites must be included. The commenter would also welcome monitoring at all well sites for the life of the site, until the wells are properly plugged. Well site owners/operators should also have to submit a well closure plan that includes the necessary steps to close the wells, including plugging all wells, documenting financial assurance to complete the well closure, and scheduling for completing closure activities.

Commenters (2177-Ute Indian Tribe, 2181-Ute Indian Tribe of the Uintah and Ouray Reservation) support the proposed AVO and OGI monitoring frequencies until all wells are plugged, equipment removed, and no fugitive emissions are present.

Commenter (2236-PSR) adds leaking equipment, such as valves, pumps, and connectors, are a large source of emissions of VOC and volatile HAP and the EPA and its state counterparts such as the Department of Environmental Protection in Pennsylvania must improve and increase the

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<sup>137</sup> 87 Fed. Reg. at 74,736.

<sup>138</sup> Colorado APCD PS Memo 14-04, p.10, (May 16, 2022), available at <https://cdphe.colorado.gov/air-permitting-guidance-memos>.

<sup>139</sup> 2 Colo. Code Regs. § 404-1-434.d.(11).A.

<sup>140</sup> 2 Colo. Code Regs. § 404-1-434.d.(11).D.

<sup>141</sup> N.M. Code R. § 20.2.50.116.C.(3)(g).

work of leak detection and repair. The commenters have a massive amount of orphaned and abandoned wells in the state of Pennsylvania.

Commenter (2315-DEC) agrees that proper well closure is important to minimize risk to nearby communities. The commenter's well plugging program focuses on protection of both air and water quality. Their well plugging requirements are designed to prevent brine and hydrocarbons from moving through the well bore and contaminating freshwater aquifers or from escaping at the surface. However, states should have the flexibility to allow gas venting where the risks to groundwater are judged too high.

Commenter (2408-Colorado Local Government Coalition) recommends EPA require operators review, and revise if appropriate, well closure plans for all wells they acquire in an asset transfer transaction. Purchasers should be required to update well closure plans if any circumstances covered by the well closure plan have changed. Specifically, purchasers must provide EPA with an updated well closure plan if any of the following has changed since the original submission of the well closure plan: the steps necessary to close all wells at the well site, including plugging of all wells; the financial requirements and disclosure of financial assurance to complete closure; and the schedule for completing all activities in the closure plan. This will ensure well closure plans remain relevant and up to date.

Commenters (1643-Ohio River Valley Institute (ORVI), 2201-West Virginia Highlands Conservancy, 2212-On behalf of the Union of Concerned Scientists, 2392-Earthjustice et al., 2410-California Office of the Attorney General et al., 2447-Clean Air for the Long Haul) agree with the EPA that idled and unplugged wells can be large sources of emissions.

Commenter (2429-Wyoming Outdoor Council) states, according to estimates from the Wyoming Oil and Gas Conservation Commission, Wyoming has more than 1,300 documented abandoned oil and gas wells on state and private lands alone.<sup>142</sup> These wells are a source of unregulated emissions as well as a liability for citizens and taxpayers. It is critical that EPA's final rule addresses reducing emissions from these wells and establishes clear guidelines for future well closures, such as requiring a closure plan and post-closure OGI surveys to avoid this problem in the future.

Commenter (2433-EDF et al) strongly support EPA's proposal to ensure that all sites are affected facilities subject to some form of ongoing monitoring. Significant emissions, including super-emitter events, have been observed at marginal wells,<sup>143</sup> shut-in wells,<sup>144</sup> abandoned wells<sup>145</sup> and wellheads,<sup>146</sup> underscoring the importance of regular monitoring at these sites until they are properly plugged. These sites are typically older and declining in production, meaning they are

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<sup>142</sup> Wyoming Oil and Gas Conservation Commission. Orphaned Well Site Plugging, Remediation, and Restoration.

<sup>143</sup> Mark Omara et al., Methane emissions from US low production oil and natural gas well sites, 13 Nat. Commc'n 2085 (2022), <https://www.nature.com/articles/s41467-022-29709-3>; Deighton et al., *supra* note 123.

<sup>144</sup> Amy Townsend-Small, Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water, *Env't Rsch. Letters* (2021), <https://iopscience.iop.org/article/10.1088/1748-9326/abf06f>.

<sup>145</sup> Mary Kang et al., Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania, 51 PNAS 18173 (2014), <https://www.pnas.org/doi/10.1073/pnas.1408315111>; James Williams et al., Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, 55 *Env't Sci. Tech.* 563 (2020), <https://pubs.acs.org/doi/10.1021/acs.est.0c04265>.

<sup>146</sup> Riddick et al., *supra* note 151; Bowers Report, *supra* note 147, at 19.

less likely to be regularly visited or prioritized for equipment upgrades and repairs. Aging and poorly maintained equipment at these sites can easily fail and leak. EPA's proposed AVO monitoring requirements therefore address an important problem and can both help to prevent emissions and mitigate existing or recurring problems.

Commenter (2433-EDF et al) highlight that exempting declining sites from regulatory requirements could exacerbate end-of-life well issues.<sup>147</sup> This could happen in at least two ways. First, exempting declining sites from inspection requirements means they can exist in a regulatory gray area, subject neither to standards for active wells nor standards for well closure. This may be desirable to operators who seek to avoid facing the costs of plugging and closure.<sup>148</sup> Second, regulatory exemptions for declining sites may increase their attractiveness to potential buyers, some of whom are likely to become insolvent or lack the funds for proper closure.<sup>149</sup> As leading operators seek to reduce emissions, they may offload underperforming and high-emitting assets to private companies lacking environmental commitments or those with business models aimed at prolonging the life of declining assets. This "transferred emissions problem" is a growing concern that can negatively impact emission reduction efforts.<sup>150</sup>

Response II-4-70: The EPA acknowledges supportive comments. As proposed, the EPA is finalizing the requirement to continue fugitive monitoring for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.

Comment: Commenters expressed disagreement with EPA's proposed well closure requirements. Comments on the specific well closure requirements are provided below.

Commenter (2337-KDHE) disagrees with the proposed requirement, particularly for EG OOOOc, that monitoring at all well sites continue for the life of the site, until the wells are properly plugged, and a final monitoring survey using OGI shows there are no emissions. Operators with wells that are not producing oil and/or gas should not have to bear the burden of continual periodic monitoring. The commenter would agree with an initial survey of non-producing wells (exempting Class I and Class II disposal wells as included in the proposed Emissions Guidelines document) and require repair of any leaks found at that time. Beyond that, however, non productive wells, the great majority of which are already pending plugging operations, would be considered exempt from monitoring by the commenter on the basis of remaining useful life (RULOF).

Commenter (2353-CrownQuest Operating, LLC.) states the EPA uses the referenced study<sup>151</sup> to support more monitoring and reporting on temporarily abandoned, plugged, and abandoned wells. Firstly, the authors mentioned nothing about their sampling method. The EPA only selected 37 wells to study in Pecos County. Such a sampling method is not random, which would

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<sup>147</sup> 2022 Joint Environmental Comments, *supra* note 1, at 108-09.

<sup>148</sup> See, e.g., Zachary R. Mider and Rachel Adams-Heard, *supra* note 124.

<sup>149</sup> See *id.*

<sup>150</sup> Env't Def. Fund, *Transferred Emissions: How Risks in Oil and Gas M&A Could Hamper the Energy Transition* (2022), <https://business.edf.org/insights/transferred-emissions-risks-in-oil-gas-ma-could-hamper-the-energy-transition/>.

<sup>151</sup> Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water <https://iopscience.iop.org/article/10.1088/1748-9326/abf06f/pdf>.



make the data unusable due to human bias in the selection process. The commenter adds Pecos County is known for having very corrosive water and old equipment; it is hardly representative of the Permian basin or the US. In this study, the researchers acknowledge that they tested wells in a region (The Permian) with a uniquely high methane exhaust. Understanding these characteristics is of utmost importance when looking at the data of this study.

Commenter (2353-CrownQuest Operating, LLC.) states the EPA uses the referenced study<sup>152</sup> to justify adding reporting requirements to plugging wells. Not only is this duplicative with other regulations, but it is outside of the EPA's jurisdiction. Well-closure requirements are within the jurisdiction of State Oil and Gas Commissions and other agencies, not the EPA. State law requires a well to be plugged and abandoned when it has reached the end of its useful life.

Commenter (2353-CrownQuest Operating, LLC.) states the EPA identified leaks at 19 of the 37 sites. Of these 19 sites, 11 detections fell below the threshold of EPA-approved OGI cameras used in the LDAR surveys conducted under OOOOa regulations. Knowing that only 22% of wells were emitting at a concentration detectable through approved EPA inspection methods in an area with uniquely high methane emissions is not substantial enough evidence to base such broad inspection regulation on TA and P&A wells. It is unreasonable to apply the findings of such a microscopic study in one specific region to the whole industry. The EPA appears to have confirmation bias considering the study's scope and application in the preamble.

Commenter (2353-CrownQuest Operating, LLC.) adds all states require operators to provide written notice of plugging and comply with regulatory requirements to P&A the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration, and restoring the surface site. The EPA should gather these records by request through the States rather than burdening operators with unnecessary and redundant reporting.

Commenter (2353-CrownQuest Operating, LLC.) states the EPA uses the referenced study<sup>153</sup> to support more monitoring and reporting on temporarily abandoned wells and plugged and abandoned wells. This study investigates emissions from plugged, unplugged, and idle wells in California, which is not a credible scientific data-gathering method to apply broadly across a large geographic area. The authors admit, "due to limited access, we could not measure wells in most major active oil and gas fields in California."

Commenter (2353-CrownQuest Operating, LLC.) argues a few poorly maintained old wells in California (not even in main production areas) do not represent oil and gas production across the US. Additionally, the two methods of inspection that the authors used do not meet the EPA's LDAR inspection requirements according to Method 21. This study fails to support further monitoring and regulation because it does not show adequate evidence that nationwide wells of this category have significant emissions issues or that more regulation would fix the problem.

Response II-4-71: The EPA acknowledges the comments provided regarding the reports cited in EPA's December 2022 Supplemental Proposal in the context of the proposed well closure

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<sup>152</sup> Methane Emissions from Abandoned Oil and Gas Wells in California.  
<https://pubs.acs.org/doi/full/10.1021/acs.est.0c05279>.

<sup>153</sup> Methane Emissions from Abandoned Oil and Gas Wells in California  
[<https://pubs.acs.org/doi/full/10.1021/acs.est.0c05279>].

requirements, however, the EPA disagrees with the commenter and maintains that it is crucial to ensure continued fugitive emissions monitoring on a routine basis to ensure that fugitive emissions continue to be addressed throughout the life of the well site and to prevent the well site from falling into disrepair or becoming orphaned. Therefore, as proposed, the EPA is finalizing the requirement to continue fugitive monitoring for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report. See section X.A.1.a.ii of the preamble to the final rule for details.

Comment: Commenter (2177-Ute Indian Tribe) argues well closure regulation is not appropriate in these regulations and should be removed from NSPS OOOOb and EG OOOOc. The commenter requests that the entire well closure section be removed (i.e., §60.5397b(l) and §60.5397c(l)).

Response II-4-72: The commenter provides no information to support the argument to remove the well closure requirements in the rule. The well closure requirements in the final rule remain as proposed.

Comment: Commenters (2392-Earthjustice et al., 2410-California Office of the Attorney General et al, 2447-Clean Air for the Long Haul, 2460-Private Citizen) express that throughout the history of gas and oil production, abandoned or orphaned wells have been a major problem.

Commenter (2447-Clean Air for the Long Haul) states there are in excess of 4,000,000 unplugged, non-producing, and orphaned wells within the United States.<sup>154</sup> In fact the number of documented abandoned wells shot up over 12 percent since 2008 coinciding with the start of the hydraulic fracturing boom.<sup>155</sup>

Commenters (2392-Earthjustice et al., 2410-California Office of the Attorney General et al.) note EPA estimates that, as of 2022, there existed approximately 3.7 million orphaned and abandoned oil and gas wells in the United States, of which over two million remain unplugged and continue to contribute to adverse air and water quality impacts.<sup>156</sup> Further, in 2020, abandoned oil wells emitted 219,000 metric tons of methane and abandoned gas wells emitted 57,000 metric tons of methane.<sup>157</sup>

Commenter (2460-Private Citizen) states the EPA's suggestion of making sure that plugging cost are paid upfront is certainly good. However, there are serious questions as to what the price of plugging should be. The commenter can calculate the money required to plug a well once based

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<sup>154</sup> Williams, James P., Amara Regehr, and Mary Kang. "Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States." *Environmental Science & Technology* 55, no. 1 (January 5, 2021): 563-70. <https://doi.org/10.1021/acs.est.0c04265>.

<sup>155</sup> Groom, N (2020), "Special Report: Millions of abandoned oil wells are leaking methane, a climate menace," Reuters, <https://www.reuters.com/article/us-usa-drilling-abandoned-specialreport/special-report-millions-of-abandoned-oil-wells-are-leaking-methane-a-climate-menace-idUSKBN23N1NL>.

<sup>156</sup> EPA 2022 Greenhouse Gas Inventory, supra n.39, at 3-108 (explaining that only 41% of abandoned wells are properly plugged).

<sup>157</sup> U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2020, at p. 3-108 [2021 GHGI], available at <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gasemissions-and-sinks-1990-2020>. These numbers are likely an underestimate. See Att. 29, Williams et al., Methane Emissions from Abandoned Oil and Gas Wells in Canada and the United States, 55 Env. Sci. Tech. 563 (2020) (finding that annual methane emissions from abandoned wells are underestimated by 20% in the U.S.).

on the size of the well head. The problem is that, with current cement technology, these plugs may have rather short lifetimes, with most of the plugs failing before 50-100 years have passed. The wells will most likely resume leaking methane and other contaminants once the plugs have failed. Should a company be charged for one plug? Or 10? Or 100? Commenter (2460-Private Citizen) argues we need to stop almost all new drilling for gas before the end of this decade. Most wells will need to be decommissioned before 2050. The end of the fossil fuel industry as we know it is coming into sight. Unfortunately, leakage from old wells may last forever.

Commenter (2460-Private Citizen) notes there is promising new technology that suggests that we may be able to produce much stronger and longer lasting cement plugs in the future. A report from MIT highlights research that suggests why Roman cement has survived for millennia.<sup>158</sup> A 2020 paper discusses how nanoengineering approaches can be applied to improving repairs in leaking underground cement casings.<sup>159</sup> Some parts of this research might be applicable to cement plugs. New techniques for improved cement plugs may provide longer lifetimes at an increased cost. It isn't yet clear what the cost of long-lasting plugs will be, but it seems to me that the money required from companies should be greater than needed for just one plug per well using current technologies.

Response II-4-73: The EPA acknowledges comments. As proposed, the EPA is finalizing the well closure requirements to continue fugitive monitoring for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.

#### 4.1.6.2 Outside EPA Jurisdiction

Comment: Commenters (2166-ODNR, 2202-TXOGA, 2219-WOGCC, 2223-Texas Alliance of Energy Producers, 2248-North Dakota Petroleum Council (NDPC), 2254-PBPA, 2258-Marcellus Shale Coalition (MSC), 2294-Ohio Oil and Gas Association, 2298-Pioneer Natural Resources USA, Inc., 2308-National Stripper Well Association, 2326-AXPC, 2337-KDHE, 2353-CrownQuest Operating, LLC., 2401-State of Wyoming, 2403-PAO, 2428-API, 2446-IPAA) do not believe that EPA has the statutory authority to require financial assurance plans and well closure reports from the regulated community. Matters regarding orphaned wells are typically outside of EPA's jurisdiction, resting instead with other federal government departments and with state-level oil and gas commissions.<sup>160</sup>

Commenters (2166-ODNR, 2168-INOGA, 2172-KOGA, 2211-Lambda Energy Resources, 2213-Occidental (Oxy), 2315-NY DEC, 2214-BCAO, 2219-WOGCC, 2223-Texas Alliance of Energy Producers, 2227-Western Energy Alliance, 2252-PAW, 2254-PBPA, 2258-Marcellus Shale Coalition (MSC), 2288-North Dakota Department of Environmental Quality, 2294-Ohio Oil and Gas Association, 2298-Pioneer Natural Resources USA, Inc., 2308-National Stripper

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<sup>158</sup> <https://news.mit.edu/2023/roman-concrete-durability-lime-casts-0106A>.

<sup>159</sup> <https://www.sciencedirect.com/science/article/abs/pii/S1750583620306125?via=ihub>.

<sup>160</sup> See e.g., Press Release, U.S. Dep't of the Interior, Through President Biden's Bipartisan Infrastructure Law, 24 States Set to Begin Plugging Over 10,000 Orphaned Wells (Aug. 25, 2022) (on file with author) ("The Department of the Interior today announced it has awarded an initial \$560 million from President Biden's Bipartisan Infrastructure Law to 24 states to begin work to plug, cap and reclaim orphaned oil and gas wells."); Colorado Oil & Gas Conservation Commission, Orphaned Well Program FAQ (Mar. 26, 2021) (on file with author) ("COGCC is launching the Financial Assurance Rulemaking, as required by SB 19-181, to address financial assurance requirements in Spring 2021.).

Well Association, 2326-AXPC, 2337-KDHE, 2388-ExxonMobil, 2403-PAO, 2428-API, 2439-State of Michigan Department of Environment, Great Lakes and Energy, 2446-IPAA) believe that EPA should rely upon the existing plugging and abandonment procedures in each state in determining when such plugging and abandoning has occurred. First, each oil and gas state has different and specific rules regarding plugging and abandonment. Each state has a relevant oil and gas commission or department with existing procedures relating to plugging and abandonment. Importantly, those regulations typically define when plugging and abandonment must occur, the notification requirements for plugging and abandonment and the requirements that must be followed in plugging and abandoning a well. Further, states also typically have existing provisions and requirements regarding financial assurance (typically put in place well before abandonment of the well is contemplated). EPA's proposed well closure plan does not consider these existing frameworks and may contradict these existing frameworks – among other problems.

Commenters (2166-ODNR, 2238-SOOGA, 2294-Ohio Oil and Gas Association) state the ODNR already administers a comprehensive regulatory program governing well plugging and abandonment. Ohio's current plugging rules not only address the isolation of natural gas and oil to the formation from which it originated but also consider the protection of ground water and natural resources. Ohio rules also address standards for materials to be used in the process of plugging a well. Commenter (2166-ODNR) requires inspectors to witness well plugging and has trained staff able and ready to do so. The commenters are unaware of evidence demonstrating that already required plugging plans are inadequate.

Commenter (2166-ODNR) finds many state oil and gas regulatory programs require blanket bonds as a means of providing financial assurance for the proper operation of the wells and plugging and abandonment of the wells. The amount of the financial assurance varies from state to state, but in Ohio the amount of a blanket bond is \$15,000. If an oil and gas operator has two oil and gas wells or 2,000 oil and gas wells, the amount of bond required is \$15,000. Should the proposed air emissions rule be adopted and if the cost of the emissions control requirements under the rule become too great, there is a high probability that an operator may abandon all of their wells and forfeit their bond. While Ohio has legal recourse to work to obtain funding from an operator in this example, it is a lengthy process that would result in wells sitting idle without a responsible owner. Worst case scenario, if the operator declares bankruptcy and has no money, Ohio will have the additional wells added to its orphan well inventory. Ohio's orphan well program could grow exponentially if enforcement against the operator fails or if the operator declares bankruptcy.

Commenter (2166-ODNR) continues, under the above-described scenario, the state would then have the responsibility to plug those wells. In Ohio, five companies own more than 16,000 wells. The current average cost to plug a well in Ohio is approximately \$125,000 and is likely to increase with inflation. Should those top five operators abandon all their wells, the plugging liability for the state at today's cost would be more than two billion dollars. In such a case, the burden to the state would be great, and it would defeat purposes established under the Infrastructure, Investment, and Jobs Act, which provided money to states to plug orphan wells to eliminate methane emissions. Even if a portion of the wells would be abandoned by operators, the impact would overwhelm Ohio's orphan well program.

Commenter (2166-ODNR) requests that the EPA remove the applicability of the rules to oil and gas wells that were constructed prior to November 15, 2021. The commenter requests the EPA look at a top-down BACT approach to OOOOb and a RACT approach to OOOOc since there is a potential for significant construction at an existing facility to implement the proposed BSERs.

Commenter (2294-Ohio Oil and Gas Association) argues ODNR's regulatory program governing the plugging and abandonment of wells in Ohio is robust and adequately addresses the concerns that EPA raised regarding the need for a well closure program in the Supplemental Proposal. The commenter provided several notable provisions of Ohio law and ODNR's regulations in their comment letter citing language from various provisions in Section 1509 Division of Oil And Gas Resources Management - Oil And Gas, including 1509.062 Temporary Inactive Well Status, 1509.07 Liability Insurance Coverage, 1509.11 Statement of Production of oil, gas and brine, 1509.12 Defective Wells and Well Plugging.

Commenter (2294-Ohio Oil and Gas Association) notes that ODNR's existing statutory authority and regulatory framework governing abandoned wells is robust, and adequately addresses EPA's concerns regarding such wells. The commenter, whose members operate in several other states, notes that other states have programs regulating abandoned wells similar to ODNR. Accordingly, EPA need not and should not insert itself into this state-led regulatory arena. The commenter states that should EPA proceed with the redundant well closure requirements, the plugging and abandonment of one well at a multi-well site should not require the plugging and abandonment of all wells at the well site.

1. EPA should allow for scheduling flexibilities in completing the well closure activities and eliminate the requirement to conduct an OGI to confirm no emissions from the well post-closure.

Commenter (2304-PIOGA) adds Pennsylvania requires well owners to post a bond or bonds for their wells. PADEP requires plugging with Class A Cement Column. PADEP also has detailed reporting requirements associated with plugging wells, including having PADEP personnel onsite during the plugging operation and requiring the equivalent of a closure report. The reality is each plugging operation is different because the well bore conditions are different, and unknown with certainty. The commenter's members work with PADEP personnel onsite to determine the best way to plug the wells. Respectfully, EPA dictating additional requirements and paperwork provides no additional environmental benefit and creates inefficiencies for owners/operators. The Supplemental Proposal's requirement of an OGI survey for every closed well is excessive and not cost-justified.

Commenters (2168-INOGA, 2172-KOGA, 2247-Ohio EPA) note the administrator will likely receive hundreds or maybe thousands of well closure plans. The commenters ask if EPA evaluated the workforce that will be needed to review these plans and whether this should take place at the federal level or should state resource agencies be in charge of well closure plans. If state agencies are in charge, commenters ask if there will be additional federal funding to assist the state in fulfilling this extra regulatory function.

Commenters (2166-ODNR, 2168-INOGA, 2172-KOGA, 2214-BCAO, 2219-WOGCC, 2227-Western Energy Alliance, 2237-Industrial Commission of North Dakota, 2238-SOOGA, 2288-North Dakota Department of Environmental Quality, 2252-PAW, 2258-Marcellus Shale

Coalition (MSC), 2294-Ohio Oil and Gas Association, 2298-Pioneer Natural Resources USA, Inc., 2304-PIOGA, 2310-Montana Department of Environmental Quality (DEQ), 2315-NY DEC, 2326-AXPC, 2439-State of Michigan Department of Environment, Great Lakes and Energy) provide state-specific comments on their state submission plans. Commenters argue this provision of the rule is unnecessary because the items it intends to require are already handled through other regulatory bodies. The CAA should not be used to add additional layers of redundant requirements. At a minimum, the rules should provide overlap provisions for equivalent state and federal requirements.

Commenter (2227-Western Energy Alliance) states the proposed rules should not require well closure plans. NSPS OOOOb and EG OOOOc should not require continued fugitive emissions monitoring surveys following the plugging and abandonment of a well or site.

Commenter (2227-Western Energy Alliance) provides an example, the 500 Series Rules of Practices and Procedure administered by the Colorado Oil and Gas Conservation Commission (COGCC) require operators to file an application to require plugging and abandonment of a well or closure of an oil and natural gas location. An operator of a well site that is a fugitive emissions component affected facility should be able to cease fugitive emissions monitoring surveys upon closure of the well or site, as provided by the state or federal authority regulating the oil and natural gas industry.

Commenters (2237-Industrial Commission of North Dakota, 2288-North Dakota Department of Environmental Quality) state North Dakota already has a long established well plugging procedure managed through the North Dakota Oil and Gas Division where plugging procedures are reviewed by the Division, aimed at protecting not only the oil and gas production zones from contamination but more importantly the freshwater aquifers that may exist around the well. The well closure plans appear to be redundant considering this review.

Commenter (2248-NDPC) requests that well closure requirements be removed. The EPA's involvement with the plugging and abandonment of oil and gas wells is unwarranted and is under the authority of the North Dakota Industrial Commission (NDIC). The commenter states North Dakota Legislature is currently considering a bill that would allow low producing wells to be idled in preparation for the use of enhanced oil recovery (EOR) methods in the future. EOR has proven to be a success in older wells in North Dakota that would normally be plugged and abandoned. In lieu of that, the ability to idle until the new technology is available prevents large volumes of oil from being stranded. The proposed rule would require operators to unnecessarily monitor those idled wells with OGI when emissions from those wells are minimal.

Commenter (2252-PAW) argues the Wyoming Oil & Gas Commission has a program in place to ensure plugging and abandonment activities occur in line with appropriate practices.

Commenter (2252-PAW) asks does the EPA assume to require different standards of companies through these plans than the companies are already subject to through other regulatory bodies. Does the EPA intend to require wells be closed based on its own judgment, or require additional financial assurance if it deems the BLM's amount insufficient? The EPA should remove all provisions and remove itself from any oversight with regard to well closure.

Commenter (2310-DEQ) notes Montana’s Board of Oil and Gas Conservation follows regional guidelines to plug orphaned wells. In addition, each abandonment plan is evaluated individually to ensure that adequate protections are incorporated. Again, Montana already has an established program to plug orphaned wells and reclaim the area around them.

Commenter (2337-KDHE) disagrees with the requirement for well closure plans, including steps to close the wells, including plugging all wells, documenting financial assurance to complete the well closure, and scheduling for completing closure activities (including any final OGI monitoring), which would effectively duplicate state requirements already in place by the Kansas Corporation Commission (KCC) and may constitute EPA overreach.

Commenters (2168-INOGA, 2172-KOGA) do not deny that wells were inappropriately plugged decades ago. Industry and state agencies have learned about how to appropriately plug wells and have adequately updated their regulations to reflect the current best practices to complete well plugging work. Commenter (2172-KOGA) adds specifically in Kentucky, the EPA’s involvement will require additional agreements to be developed between the Division of Oil and Gas (oversees oil and gas well permitting, operation, and plugging activities) and the Division for Air Quality (oversee compliance with EPA’s emissions regulations). This requirement will be an additional burden on the two state agencies that are at capacity with maintaining their current workload. EPA will be imposing undue burdens on the Division for Air Quality to monitor work that is satisfactorily performed by the Division of Oil and Gas. There is no added value with this requirement.

Commenters (2177-Ute Indian Tribe) state well closure activities are regulated by other agencies. It is not appropriate for EPA to require notification 60 days prior to beginning well closure activities. An annual report that includes all well closures or ownership transfers would be sufficient. The commenter asks the EPA to not require a description of the schedule for completing all activities in the well closure plan.

Commenter (2219-WOGCC) notes EPA is proposing to require operators submit notice of owner or operator changes on the well. This is already required by the state and or BLM, who has regulatory authority over this process. EPA states this will prevent wells from becoming orphan. In actuality, it will do nothing to prevent orphan wells. The unnecessary and tremendous burdens this rule places on operators will create significant numbers of orphan wells as described. EPA being notified who the current operator is will do nothing to remove the burdens or prevent orphan wells.

Commenter (2214-BCAO) states Alaska already has the AOGCC which regulates well closures.

Commenter (2254-PBPA) states the Railroad Commission of Texas regulates well closure requirements within Texas, while the Energy, Minerals, and Natural Resource Department regulates such activities in New Mexico. These requirements will increase the end-of-life costs for wells, and may have a particularly big impact on small businesses operating older wells that already produce less and, therefore, have lower margins. The entire Proposed Rule, but this provision in particular, will disproportionately impact these small operators.

Commenter (2254-PBPA) reiterates a “site” may cover several leases, and there could be situations where an operator no longer has the legal right to inspect a well on a lease that has

expired. To the extent any monitoring of plugged or abandoned wells is required, operators should have flexibility to utilize remote sensing methods or aerial flyovers to reduce burdens and avoid access constraints.

Commenter (2298-Pioneer Natural Resources USA, Inc.) believes EPA should simply require tire submission of written materials required by the relevant jurisdiction reflecting the plugging and abandonment of the well. Once these materials have been submitted, then an operator may cease fugitive emissions monitoring. Relying upon the required reporting to state oil and gas commissions is appropriate and has been relied upon for many years for reporting of well completion operations under OOOO/a.

Commenter (2298-Pioneer Natural Resources USA, Inc.) believes EPA must clarify the language as "steps necessary to permanently plug all wells at a well site" and remove the phrase "including permanent plugging of all wells." For the state of Texas, the proposed requirement to provide "steps necessary to close all wells" is already completed via the required process of Texas Railroad Commission through their W-3A (Intent to Plug) procedure process. This report is required for all permanently plugging of wells. For this reason, operators shouldn't have to duplicate work and submittals when a state has an existing program and process which meets the requirements of 60.5397b(l)(i).

Commenter (2315-NY DEC) notes in states like New York, where undocumented orphaned wells could provide conduits for methane to enter a freshwater aquifer and move into a homeowner's water well and ultimately into their residence due to overpressuring in a nearby plugged well. It is especially important to consider location of wells in the context of environmental justice communities. The commenter recommends that if a state has a plan in place for these communities, that state should be allowed to select the order wells are plugged. If additional incentives are developed, it is important to work with states in determining how incentives are established and distributed.

Commenter (2388-ExxonMobil) participated in a DOE Study that found low producing wells account for about 40% of oil system methane emissions and 60% of natural gas system methane emissions.<sup>161</sup> The commenter supports EPA's proposal for some assessment of a source's emissions level to be conducted before exemptions are applied. The Agency should depend on cooperating state agency determinations for completion of plug and abandonment activities to satisfy the requirement to discontinue monitoring.

Commenter (2428-API) proposes operators maintain records of a well closure plan approved by the local authority with jurisdiction. This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

Commenter (2428-API) notes EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these

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<sup>161</sup> Department of Energy, National Energy Technology Laboratory, Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells, Project Number DE-FE0031702 (Last Reviewed 09/13/2022).



programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

Commenter (2428-API) states if EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal February 13, 2023 106 the recent “Bipartisan Infrastructure Law” to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Commenter (2446-IPAA) agrees since idle and/or abandoned wells may have emissions, some monitoring might be authorized under the CAA, but EPA has provided no BSER analysis to justify OGI over AVO when a well has been idled or plugged/abandoned. The notice, recordkeeping, bonding, and closure plans are excessive and not sufficiently linked to reducing emissions to be warranted. Additionally, in most instances, they are duplicative and/or potentially inconsistent with what states already require. States and the Bureau of Land Management currently occupy this regulatory space and EPA's proposal is unnecessary.

Commenter (2439-State of Michigan Department of Environment, Great Lakes and Energy) adds Michigan’s plugging requirements are very specific to Michigan’s geology to prevent migration of fluids (including methane) and ensure successful, permanent plugging and abandonment. One example is the proposed rule, as written, would require an operator to wait 60 days before beginning plugging operations. Waiting a prescribed number of days presents a significant threat to human health and the environment. In northern states, weather and frost laws may also be factors and could close the window for timely plugging due to waiting 60 days. If this proposal is finalized as written, the EPA or delegated state program administrator would begin regulating plugging operations on all oil and gas wells in the United States, including those wells which the EPA does not currently permit, potentially diverting resources from oversight of high-priority emitters.

Commenter (3844-Senator Kevin Cramer et al.) states the individual states and the Department of Interior have regulatory oversight authority and programs governing the tracking and remediation of wells and well sites. Congress recently passed bipartisan legislation to fund these programs and the legislation specifically relies on those authorities and programs already in place. By doing this, Congress demonstrated the existing programs and authorities were sufficient to the task, and chose not to create an additional federal bureaucracy for this purpose. Neither should the EPA.<sup>162</sup>

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<sup>162</sup> Public Law 117 - 58, Section 40601 - Infrastructure Investment and Jobs Act.

Commenter (3844-Senator Kevin Cramer et al.) argues the EPA's duplicative well-plugging language appears to require a well to be plugged if it does not produce for a period of 30 days.<sup>163</sup> This provision ignores the fact wells can be temporarily shut-in for mechanical upgrades, repairs, or in response to market forces.<sup>164</sup> For example, when the beginning of the pandemic shook oil and gas markets in early 2020 and the West Texas Intermediate spot price went negative, more than 770,000 barrels per day were taken off the market by May 2020. This was due to operators temporarily shutting in lower-margin wells and reducing flows in others. When market conditions improved, much later than 30 days, operators brought these temporarily shut-in wells back online and production returned - restoring essential energy supplies that supported the economic recovery from the pandemic.<sup>165</sup> This provision also disregards normal actions an operator may take that can leave a well idle for 30 or more days and all but prohibits transitioning mature wells for use in enhanced oil recovery, which Congress endorsed and incentivized through the 45Q tax credit. The EPA will be forcing states to regulate an oil and gas well constructed decades ago in the same manner as a new, modern well. While 20,000 new wells may be drilled annually, there are about one million existing wells - of which more than 700,000 are low- production, marginal wells. Many of these older marginal wells are owned by small, independent businesses operating on thin profit margins and cannot afford to be regulated the same as large multibillion-dollar corporations.<sup>166</sup> This one-size-fits-all best system of emissions reduction presumptive standard violates the Clean Air Act and its foundational cooperative federalism model. Under the law, the states are to implement and enforce standards of performance for existing sources with source-specific considerations and factors applied.<sup>167</sup> Further, oil and gas producing states are questioning how to fulfill the requirements of the proposal to newly regulate hundreds of thousands of low-producing wells in a relatively short period of time, particularly as no additional funding has been allotted to them to facilitate implementing what is likely an unfunded mandate.<sup>168</sup>

Response II-4-74: See EPA's rationale supporting the proposed well closure requirements provided in the December 2022 Supplemental Proposal<sup>169</sup> and in the November 2021 Proposal, including EPA's request for comment on various provisions that were considered for this program.<sup>170</sup> As described above in comments on the proposed well closure requirements as it relates to EPA's jurisdiction, EPA acknowledges that regulatory requirements exist in various states and other regulatory agency oversight occurs. However, in response to comments on the

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<sup>163</sup> "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Federal Register.

<sup>164</sup> Spilman Thomas & Battle Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." 18-19.

<sup>165</sup> Exarheas, Andreas. "Shut in Oil Production Is Coming Back." Rigzone, Rigzone.com, 17 Aug. 2020, [https://www.rigzone.com/news/shut\\_in\\_oil\\_production\\_is\\_coming\\_back-17-aug-2020-163032-article?rss=true](https://www.rigzone.com/news/shut_in_oil_production_is_coming_back-17-aug-2020-163032-article?rss=true).

<sup>166</sup> Spilman Thomas & Battle Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." 2-3.

<sup>167</sup> API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." American Petroleum Institute. 101-103.

<sup>168</sup> North Dakota Department of Environmental Quality Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." NDDEQ. 3-4.

<sup>169</sup> 87 FR 74736 (December 6, 2022).

<sup>170</sup> 86 FR 63240-63240 (November 15, 2022).

November 2021 Proposal, and as discussed in the December 2022 Supplemental Proposal, EPA is ensuring that requirements across states meet a minimum level of control, to address concerns by many stakeholders regarding continuing emissions from orphaned wells and unplugged idled wells. Studies have shown that idled wells can have fugitive emissions, and in some cases these emissions can be very large.<sup>171,172</sup> As discussed, the EPA finds that these data demonstrate the importance of continued fugitive emissions monitoring on a routine basis to ensure that fugitive emissions continue to be addressed throughout the life of the well site. Even if various states have their own requirements to address fugitive emissions from idling wells, requirements vary from state to state, and state agencies also have varying definitions for idle, inactive, dormant, or shut-in, but not plugged. State governments also have varied definitions of temporarily idled, orphaned, or non-producing wells. Also, as indicated by the EPA in the November 2021 Proposal, “The EPA recognizes that many oil and natural gas producing States require the plugging of non-producing oil and natural gas wells, and subsequent restoration of the well site. However, the large number of abandoned, unplugged wells nationwide suggests that Federal standards may be warranted.” 86 FR 63241.

The requirement for a well closure plan represents a key element in maintaining transparency for the responsible owner or operator and will also prevent well sites from becoming orphaned in the future. The EPA is finalizing this reporting requirement in the absence of identifying other mechanisms for obtaining this information in a better way.

#### 4.1.6.3 “Cessation” Of Production

Comment: Commenters (2177-Ute Indian Tribe, 2223-Texas Alliance of Energy Producers, 2248-North Dakota Petroleum Council (NDPC), 2257-MOGA, 2294-Ohio Oil and Gas Association, 2298-Pioneer Natural Resources USA, Inc., 2308-National Stripper Well Association, 2326-AXPC), 2428-API, 2446-IPAA) note EPA’s requirement of submitting a well closure plan within 30 days of “cessation” of production. The term “cessation” is ambiguous and does not take into account the wide range of production methods, unique geology, and production profiles that exist in each oil field in the US.

Commenters (2326-AXPC, 2428-API) state EPA’s proposed language regarding well closure could be interpreted to require submission of a well closure plan any time a well has been shut in for more than thirty (30) days. Specifically, EPA’s regulations state “[y]ou must submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site.” EPA does not define cessation of production. However, there are a number of instances or reasons that a well could cease production for 30 days without that well being a candidate for closure.

Commenter (2294-Ohio Oil and Gas Association) indicates that the applicability of the well closure requirements being triggered by the “cessation” of production operations is ambiguous. A cessation in production does not necessarily mean that a well is destined for or otherwise

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<sup>171</sup> Amy Townsend-Small and Jacob Hoschouer. “Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water.” 2021 Environ. Res. Lett. 16 054081. <https://iopscience.iop.org/article/10.1088/1748-9326/abf06f>.

<sup>172</sup> Eric D. Lebel, Harmony S. Lu, Lisa Vielstädte, Mary Kang, Peter Banner, Marc L. Fischer, and Robert B. Jackson. “Methane Emissions from Abandoned Oil and Gas Wells in California.” Environmental Science & Technology 2020 54 (22), 14617–14626. DOI: 10.1021/acs.est.0c05279.

needs to be plugged and abandoned. A temporary cessation in production is quite common in the oil and gas industry and occurs for a variety of reasons including mechanical evaluations, reworking or repair of surface facilities, and to comply with government orders. The commenter requests that the word “cessation” be struck from the rule, and that EPA clarify that the development and implementation of a well closure plan be required only for wells planned for plugging and abandonment.

Commenter (2223-Texas Alliance of Energy Producers) adds wells are often temporarily shut in for mechanical considerations, wellbore issues, reworking or repair of surface facilities or government orders/enforcement.

Commenter (2298-Pioneer Natural Resources USA, Inc.) asks EPA to update the language to read “permanent cessation of production”.<sup>173</sup>

Commenter (2326-AXPC, 3818-AXPC) believes, for the requirement to submit a well closure plan within 30 days of cessation of production, EPA should clarify submittal of the plan is triggered by the operator’s intent to permanently cease production at all wells at a well site. Operators may temporarily cease production at a well site over the life of the site. Given EPA’s intent is to ensure periodic fugitive emissions monitoring occurs until a well is plugged and abandoned, it would be consistent with EPA’s intent to require submittal of a well closure plan only when the operator plugs and abandons all wells at a well site. Until such time as the operator completes the final monitoring survey to confirm no emissions following plugging and abandonment, the operator must continue to conduct leak monitoring surveys at the appropriate frequency. The commenter’s proposal would not change this requirement.

Commenters (2214-BlueCrest Alaska Operating BCO), 2219-WOGCC, 2221-Texas Pipeline Association, 2248-NDPC, 2270-Private Citizen, 2294-Ohio Oil and Gas Association, 2308-National Stripper Well Association, 2428-API, 2446-IPAA) state there are many reasons a well may be shut in for a period of time lasting longer than 30 days. This does not mean the well is at the end of its life and needs to be plugged.

Response II-4-75: The EPA is finalizing the well closure plan requirements as proposed in the December 2022 Supplemental Proposal. The EPA clarifies that that intention of the language in the regulatory text at §60.5397b(l)(1) and in §60.5420b(a)(4)(i) that refers to “cessation of production” means the permanent or final ending of production. The EPA does not find it necessary to make the suggested revision in the final regulatory text.

#### 4.1.6.5 Financial Assurance Requirement

Comment: Various recommendations were received from commenters on the financial assurance requirements in the proposal. These comments are described below.

Commenter (2039-Citizens to Preserve Ligonier Valley, Inc.) notes that bonds are not sufficient to ensure compliance with well closure.

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<sup>173</sup> Note that Colorado has “well closure” process and it is only required for permanent closing of wells.

Commenter (2184-Social Responsibility Climate Ambassador) states that fracking and oil well sites are routinely monitored for leaks while in operation, and then when closed that they are closed using all available protective measures to ensure they do not leak. This must be done by requiring that drilling companies provide a nonrefundable bond before drilling or to continue drilling -- to prevent drillers from declaring bankruptcy without paying for these preventive measures to close drill sites properly.

Commenter (2298-Pioneer Natural Resources USA, Inc.) argues EPA needs to clarify “financial requirements” and “financial assurance.” These requirements to collect and submit need to be defined or explained with more context. For the state of Texas, the proposal requirement to provide "financial requirements" and “financial assurance” is already completed via the required process of Texas Railroad Commission through their annual P5. This report is required for all organizations and lists all inactive wells the company owns.

Commenter (2298-Pioneer Natural Resources USA, Inc.) believes exemptions should be added for operators who meet/are already meeting the 60.5397b(1)(ii) requirements through their state's program. The commenter's P5 (Organizational Report as well as renewals) with the Texas Railroad Commission are required annually. All inactive wells must be in compliance with the regulations and show they have not failed H-15 (fluid level). The commenter must also submit the following in order for the P5 to be approved/reapproved every year:

- Executed form P5 Organization Report
- Executed form P5O Organization Report Officer Listing
- Check in the amount of \$2,812.50 for P5 filing fee
- Form W3-X Application for Extension of Deadline
- Executed Continuation Certificate for Blanket Performance Bond
- Certificate of Good Standing from the Texas Comptroller of Public Accounts
- W-3C Certifications w/back up data.

Commenter (2252-Petroleum Association of Wyoming (PAW)) argues it is unnecessary for EPA to require companies to disclose their financial assurances to cover the cost of closing a well. State regulators, or other federal agencies such as the BLM, already have requirements for this. Again, this is a redundant and unnecessary function for the EPA to insert itself.

Commenter (2335-Private Citizen) argues oil and gas development companies must be required to provide a bond of a sufficient amount to pay for the monitoring and to ensure that any future problems can be remedied without the spending of significant government funds. This has not been the case in the past.

Commenter (2392-Earthjustice et al.) recommends suggests the inclusion of an estimate of actual closure costs.

Commenter (2425-TCS) states EPA should require financial assurance disclosures to include the bond coverage as well as plugging cost estimates per well, to help evaluate and identify any potential shortfall in cleanup liabilities. For example, the Bureau of Land Management (BLM), which oversees the federal onshore oil and gas program, accepts three types of bond coverage: individual lease bond, statewide bond, and nationwide bond. Due to the prevalent use of blanket

bonds, the average value of bonds held by the BLM in 2018 was \$2,122 per well, while full reclamation costs can range from \$20,000 per well to \$145,000 per well. Due to insufficient bonding, taxpayers will be paying \$46.2 million to plug orphaned wells and inactive wells at risk of becoming orphans. Many states also accept blanket bonds and are facing the same cleanup liability issue. Therefore, identifying the shortfall between actual reclamation cost and bond coverage is paramount before wells become orphaned. Commenter (2425-TCS) also urges the EPA to make financial assurance disclosures and reclamation costs, as well as all information required in well closure plans, publicly available, barring any confidentiality requirements, to increase transparency and accountability of the well plugging process.

Commenter (2433-EDF et al) notes that operators may claim that a statewide bond is sufficient to cover their plugging costs. If a statewide bond is relied on, EPA should require operators to say how much of that bond is allocated to each of their wells. In many cases, the minimum required statewide bond is not actually sufficient to cover the costs of plugging all of an operator's wells in the state. Available financial assurance for well closure should therefore be calculated and demonstrated on a per-well basis. For example, if the operator has posted a \$100,000 blanket bond to cover 500 wells in the state, the operator should report that \$200 are available for well plugging activities. Recent literature estimates typical well plugging costs of \$20,000 for plugging only and \$75,000 for plugging and surface reclamation, with horizontal wells sometimes reaching hundreds of thousands of dollars.<sup>174</sup> Table 5 within the commenter's attachment shows how much money would be available per well for closure assuming a \$20,000 cost, underscoring the inadequacy of most statewide bonds.<sup>175</sup>

Commenter (2433-EDF et al) states the financial demonstration required by EPA should contain an estimate of actual closure costs per well so that EPA and stakeholders can evaluate whether the operator's finances are actually sufficient to close the well in question. Financial requirements to close the well should be based on actual plugging costs from operators' previous plugging operations or the best available data for the well type and region, and should account for the relevant state or federal agency plugging requirements. Subject to confidentiality, these financial requirements and assurance disclosures should be made publicly available and easy to download. EPA should also require operators to submit a financial demonstration immediately in the first annual report and to reaffirm it each year. The commenter recommends that in addition to the schedule for completing the well closure, operators report the physical activities needed to close the well and the requirements of the relevant state and federal agencies. The submitted schedule should enumerate all steps necessary to close each well and the estimated timing of each.

Commenters (2219-WOGCC, 2202-TXOGA, 2428-API) explain emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. If EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the CAA to impose a financial assurance requirement. EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit

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<sup>174</sup> Daniel Raimi et al., Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers, 55 *Env't. Sci. Tech.* 10224 (2021), <https://pubs.acs.org/doi/10.1021/acs.est.1c02234>.

<sup>175</sup> The full analysis is presented in *Env't Def. Fund., Well Bonding Tables* (included as Attachment I).

comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Commenters (2219-WOGCC, 2202-TXOGA, 2428-API) state the December 2022 Supplemental Notice did not identify any provision of the CAA §111 that provides it with the authority to issue these financial assurance requirements.<sup>176</sup>

Commenter (2202-TXOGA) is also unaware of any such provision. While Congress may have delegated to EPA the power to collect financial assurance reports in the Resource Conservation and Recovery Act, Congress was silent on this matter in the CAA.<sup>177</sup> EPA cannot claim an implicit grant of statutory authority to require this information from owners and operators.<sup>178</sup> In sum, well closure should be monitored until plugged and financial assurance plans should be handled by other agencies, in whose jurisdiction such matters have historically fallen.

Commenter (2219-WOGCC) state EPA's proposed requirement to request financial assurance information is ill timed at best. It appears this requirement is only an attempt to address the rule's creation of additional orphan wells as detailed in previous comments in this letter. Unfortunately, it will do nothing but create even more orphan wells and again illustrates EPA's lack of understanding of the oil and gas industry.

Commenter (2219-WOGCC) notes there are many reasons a well may be shut in for a period of time lasting longer than 30 days. This does not mean the well is at the end of its life and needs to be plugged. In Wyoming, there are wells that are inaccessible in the winter months and must be shut in until warmer weather when roads can be kept open and the site accessible. Shutting in these wells is prudent operatorship and does not mean the well should be plugged and should not require an operator to submit a well closure plan. In other cases, wells may need maintenance and an operator is waiting for parts, supplies, or the availability of a rig or service crew. These can all take much longer than 30 days to schedule or receive and should not trigger a well closure requirement. Other times, the operator is waiting on regulatory approvals to conduct work necessary on the well. Although the commenter attempts to review the plans and grant approvals in less than 30 days, the same cannot be said for various federal agencies that may be involved in the process for wells located on federal or tribal lands.

Commenter (2219-WOGCC) adds that in those cases where a well does need to be plugged, either because is at the end of its economic life or because of issues with the well that requires its plugging, requiring a 60-day notice to EPA prior to conducting plugging operations is problematic. This is especially true if the well has integrity issues and should be plugged as soon as possible to eliminate any risks to public health or the environment. The commenter's regulations require approval of well plugging operations through a Notice of Intent to Abandon form and also a verbal or email notice to the agency a minimum of 24 hours prior to plugging.

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<sup>176</sup> Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808.

<sup>177</sup> Compare 42 U.S.C. § 6924(a)(6) (Allowing for, among other things, "additional qualifications as to ownership, continuity of operation, training for personnel, and financial responsibility (including financial responsibility for corrective action) as may be necessary or desirable."), with 42 U.S.C. § 7414(a)(1)(A)-(G) (Silent as to "financial responsibility" or "financial assurance plans.").

<sup>178</sup> *W. Virginia v. Env't Prot. Agency*, 142 S. Ct. 2587, 2595 (2022) ("[T]he agency must point to 'clear congressional authorization' for the authority it claims.") (citing *Util. Air Regul. Grp. v. Env't Prot. Agency*, 573 U.S. 302, 324 (2014)).

Within these requirements are plans for plugging the well. These are written for the specific well and take into consideration the well construction details, current condition of the well, zones requiring protection (groundwater, mineral bearing formations, etc), and nearby features. WOGCC rules require plugging the well in such a manner that the well will not allow migration of oil, gas, or water between formations or to the surface. EPA does not have the trained petroleum engineering staff or the understanding of localized site conditions to effectively determine appropriateness of plugging operations.

Commenter (2219-WOGCC) requires operators to post financial assurance for all state and fee wells and are in place to ensure operator compliance with WOGCC rules and regulations including the plugging and reclamation of the well at the end of its life. The commenter conducts an annual review of each operator's financial assurance to ensure the amount each operator has posted is appropriate. EPA requesting financial assurance at the time of plugging requires an operator to shift available capital from plugging the well to purchasing or providing financial assurance. Many operators will have no further funds available to plug the well, which will then become orphan. When this occurs, will EPA forfeit the financial assurance and plug the well? Not likely since EPA does not have the appropriate staff to properly plug a well. Instead, it will fall to the state agency or BLM to complete.

Response II-4-76: In the December 2022 Supplemental Proposal, EPA proposed under the well closure plan requirements in §60.5397b(l)(1) that the plan include a description of the financial requirements and disclosure of financial assurance to complete closure. The final rule retains this requirement at §60.5397b(l)(ii) as a necessary element to prove final closure. As stated in the November 2021 Proposal,<sup>179</sup> “The primary purpose of detailing financial capacity as part of a compliance plan, and to potentially require some financial assurance bonding, is to ensure that State governments have adequate resources to plug oil and gas wells when the owner or operator is unwilling or unable to do so.” The EPA maintains the belief that compliance assurance for well closure requirements will necessitate financial assurance on the part of well owners and operators.

#### 4.1.6.4 AVO/OGI To Prove Final Closure

Comment: Commenter (2433-EDF et al) supports EPA’s proposal to require closure plans and post-closure OGI surveys to demonstrate that plugging has been effective. These requirements will help facilitate plugging in accordance with applicable standards while defining a clear point in time after which a well is no longer an affected facility. Commenter (2428-API) indicates that it is supportive of a final OGI survey to confirm no detected fugitive emissions after well closure.

Commenter (2433-EDF et al) recommends that EPA develop sampling methods for post-closure OGI surveys to ensure plugging has been effective. EPA should ensure all types of abandoned wells are clearly covered by the requirements and clarify who would be subject to these requirements. For example, there are “zombie wells” that are abandoned and not in operation but have a known solvent owner. The commenter believes that these wells should be subject to EPA

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<sup>179</sup> 86 FR 63241 (November 15, 2021).



fugitive monitoring standards unless and until they are properly plugged, or otherwise declared orphans and then addressed through orphan well plugging programs.

Response II-4-77: The EPA acknowledges the supportive comment. As proposed, the EPA is finalizing the requirement to conduct a final OGI survey of the well site to ensure there are no emissions following plugging all of the wells at the site and completing closure activities. Steps must be repeated until emissions are eliminated as confirmed by no emissions imaged by the OGI instrument.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2177-Ute Indian Tribe, 2223-Texas Alliance of Energy Producers, 2294-Ohio Oil and Gas Association, 2298-Pioneer Natural Resources USA, Inc., 2337-KDHE, 2446-IPAA, 2713-Northeast Natural Energy LLC) state the use of OGI to prove final closure is expensive and unnecessary. If a well is insufficiently plugged, the operator will know after the cement is pumped to protect the freshwater zones. State oil and gas agency verification of proper plugging, absence of gas cut cement, and proper plating of the well should be sufficient to ensure the plugged well is not leaking. Commenter (2439-State of Michigan Department of Environment, Great Lakes and Energy) currently utilizes OGI camera to verify inadequate plugging where other evidence exists and has made operators drill out and re-plug wells where gas cut cement has occurred. These instances should not occur if wells are plugged properly under static conditions.

Commenters (2168-INOGA, 2172-KOGA) indicate that the use of OGI to prove final closure is expensive and unnecessary for the typical Illinois Basin wells. The wells have been producing from low pressure reservoirs. Liquid and gas flow can be eliminated from most of these wells by filling the wellbore with a column of water. The static head of water (i.e., pressure) created by filling the wellbore with water is greater than the pressure of the reservoir. Filling the wellbore with cement and fresh water is sufficient to overcome reservoir pressure.

Commenters (2168-INOGA, 2172-KOGA) state a final AVO survey with soap water or possibly a survey with a “flame pack” gas leak detector should be sufficient proof of plugging without the use of expensive OGI. Commenters (2223-Texas Alliance of Energy Producers, 2713-Northeast Natural Energy LLC) state AVO or a hand-held methane detector is certainly sufficient.

Commenter (2294-Ohio Oil and Gas Association) believes EPA should allow for scheduling flexibilities in completing the well closure activities and eliminate the requirement to conduct an OGI to confirm no emissions from the well post-closure.

Commenter (2308-National Stripper Well Association) proposes regulatory requirements for inactive wells be addressed through an AVO only program, perhaps semiannually.

Commenters (2223-Texas Alliance of Energy Producers, 2308-National Stripper Well Association) argue EPA has provided insufficient technical and factual analysis to justify use of OGI when a well has been idled or plugged/abandoned. Further, EPA provided no explanation of why AVO would not suffice. The economics dictate that a well that is being plugged is more likely than not to be a low production well, and that low production well is operated by a small business. Requiring OGI when a well is plugged would place a disproportionate cost on small businesses that is not justified.

Commenter (2446-IPAA) agrees since idle and/or abandoned wells may have emissions, some monitoring might be authorized under the CAA, but EPA has provided no BSER analysis to justify OGI when a well has been idled or plugged/abandoned. EPA provided no explanation of why AVO would not suffice. The economics dictate that a well that is being plugged/abandoned is more likely than not to be a low production well and that low production well is operated by a small business. Requiring OGI when a well is plugged would place a disproportionate cost on small businesses that is not justified. The notice, recordkeeping, bonding, and closure plans are excessive and not sufficiently linked to reducing emissions to be warranted. Additionally, in most instances, they are duplicative and/or potentially inconsistent with what states already require. States and the Bureau of Land Management currently occupy this regulatory space and EPA's proposal is unnecessary.

Response II-4-78: The EPA acknowledges comments asserting that OGI to prove final closure is expensive and unnecessary and request for alternatives. However, the EPA disagrees, and as proposed, the EPA is finalizing the requirement to conduct a final OGI survey of the well site to ensure there are no emissions following plugging all of the wells at the site and completing closure activities. If any emissions are identified, the owner or operator would be required to take steps to eliminate those emissions and resurvey. The OGI survey would ensure there are no emissions present, and the well site would be considered closed and no further fugitive emissions monitoring would be required. In response to request for alternative methods to prove there are no fugitive emissions, such as the use of AVO, EPA disagrees. Detection of the smallest emissions are not easily identifiable using AVO. The use of OGI to provide final closure of the well has therefore been retained in the final rule at §60.5397b(l)(3). This requirement provides a clear indication when fugitive emissions are no longer a concern at the site, plus this requirement would prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair.

#### 4.1.6.5 Other Well Closure Requirements

Comment: Commenters (2394-Earthworks, 2403-PAO, 2410-California Office of the Attorney General et al., 2433-EDF et al, 2439-State of Michigan Department of Environment, Great Lakes and Energy) note EPA proposes to require owners and operators to develop and submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility. The plan would include: (1) The steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. The EPA is also proposing to require that owners and operators submit a notification to the Agency 60-days before beginning well closure activities. Additionally, EPA is proposing to require owners and operators to report, through the annual report, any changes in ownership at individual well sites so that it is clear who the responsible owners and operators are until the site is plugged and closed and fugitive emissions monitoring is no longer required.

Commenters (2392-Earthjustice et al., 2408-Colorado Local Government Coalition) support the requirement that an operator submit a well closure plan. However, the commenter recommends EPA require operators submit this plan at the beginning of a well's life (specifically within 30 days of receipt of approval to drill a well) rather than at the end of a well's life. This is necessary to ensure that operators have an adequate plan in place to ensure the proper plugging and abandonment of all wells. The time when an operator is best positioned to put aside resources to

cover the costs of properly plugging, abandoning, and reclaiming any environmental contamination, is during the initial phase of well development. It is then that a well is most productive and the operator has access to a steady revenue stream from hydrocarbon production. Waiting to require a well closure plan until a well is at the end of its life, and thus at the tail end of its productive, revenue-generating life, could lead to the submission of inadequate plans.

Commenter (2326-AXPC) states nothing in EPA's preamble suggests that EPA is intending to use (or even legally could use) these well closure plan requirements to mandate the plugging and abandonment of wells. EPA's preamble makes clear that EPA simply intends to have written confirmation of plugging and abandonment of the well before an operator may cease fugitive emissions monitoring. Fortunately, EPA does not need to create a new well closure plan to obtain this information. Rather, EPA should simply require the submission of written materials required by the relevant jurisdiction reflecting the plugging and abandonment of the well. Once these materials have been submitted, then an operator may cease fugitive emissions monitoring. Relying upon the required reporting to state oil and gas commissions is appropriate and has been relied upon for many years for reporting of well completion operations under OOOO/a.

Commenter (2326-AXPC) believes, for the requirement to submit a well closure plan within 30 days of cessation of production, EPA should clarify submittal of the plan is triggered by the operator's intent to permanently cease production at all wells at a well site. Operators may temporarily cease production at a well site over the life of the site. Given EPA's intent is to ensure periodic fugitive emissions monitoring occurs until a well is plugged and abandoned, it would be consistent with EPA's intent to require submittal of a well closure plan only when the operator plugs and abandons all wells at a well site. Until such time as the operator completes the final monitoring survey to confirm no emissions following plugging and abandonment, the operator must continue to conduct leak monitoring surveys at the appropriate frequency. The commenter's proposal would not change this requirement.

Commenter (2392-Earthjustice et al.) recommends that operators submit a schedule enumerating all steps necessary to close the well along with estimating timing for each activity.

Commenters (2223-Texas Alliance of Energy Producers, 2308-National Stripper Well Association) argue the notice, recordkeeping, bonding, and closure plans included in the proposed rule are excessive and not sufficiently linked to reducing emissions. Commenters (2308-National Stripper Well Association, 2446-IPAA) note EPA provides no justification or rationalization for requiring a description of the steps to close all wells at the well site when it is not uncommon for simply one well to be identified as uneconomical and thus slated for plugging while remaining wells remain in service.

One commenter (2453-CMRMI) supports the EPA proposal to require owners and operators to communicate all changes of ownership of individual well sites through annual reports to increase visibility and reinforce each new owner's responsibilities. Given orphaned wells often have no defined legal and responsible owners, improperly closed and orphaned wells are at risk of indefinitely producing emissions. The commenter notes that the inclusion of this disclosure in annual reports, as clear documentation, consolidated within the EPA's repository, should decrease confusion regarding ownership and associated obligations. Annual reports should include information about owners, operators if different, and certification of notification to relevant state authorities (departments of environmental quality, counties, oil and gas authorities,

etc.) for record keeping and consistency between state and federal agencies. Many state authorities already require such notifications and checking that such steps are processed in federal annual reports would greatly increase participation and improve the accuracy of state-wide databases. Similarly, other relevant information such as state customer numbers, authorized signatories, site contact information, and corporate/administrative contact information could be included to further synchronize state and federal databases. If state-wide databases are up-to-date and in sync with federal databases, state authorities may be able to better assist the EPA in preventing orphaned wells and ensuring proper well closure.

Furthermore, commenter (2453-CMRMI) notes that change in ownership may affect sites included within the super-emitter program. As the EPA is seeking comment on all aspects of this proposed program, we recommend also sharing information regarding changes in ownership with the super-emitter public database, in order to highlight if ownership has changed since notice of the event.

Response II-4-79: EPA is finalizing the well closure requirements as proposed, which requires the inclusion of the steps necessary to close all wells at the well site, including permanent plugging of all wells as well as submitting a description of the schedule for completing all activities in the well closure plan. The EPA is maintaining the requirement that owners and operators submit a notification to the Administrator 60 days before beginning well closure activities, but EPA does not believe it is necessary for operators to submit their schedule in advance of the planned well closure activities.

The final well closure plan is intended to demonstrate that a well site has reached that point where it is appropriate to cease fugitive monitoring, and the steps necessary to close all wells at the well site, including plugging of all wells; the financial requirements and disclosure of financial assurance to complete closure; and the schedule for completing all activities in the closure plan. The well closure plan makes sure owners or operators detail the necessary information in order to ensure compliance.

Comment: Commenter (2418-South Dakota Department of Agriculture and Natural Resources (DANR)) notes on page 74736 of the preamble, EPA requests comment on additional provisions that could be added, including, for example, automatic consequences for missed monitoring reports, as a means of assuring that companies remain engaged with the site, including conducting monitoring, until all the wells at the site are properly closed.

Commenter (2418-DANR) responds, South Dakota is a rural state, which means companies and the state may need to drive hundreds of miles to reach a regulated site. In addition, South Dakota's significant weather changes (e.g., winter blizzards) can impact travel and mail delivery. As such, the commenter recommends EPA not add automatic consequences for any type of late or missing reports but instead give states flexibility in their decision making on enforcement responses.

Commenter (2410-California Office of the Attorney General et al.) suggest an automatic consequence for an owner's or operator's repeated failure to submit monitoring reports should include a requirement to permanently cease production, submit a well closure report, and permanently plug all wells at the site. When owners and operators are no longer monitoring and staying engaged with well sites there is a greater potential for them to deteriorate and leak or

become orphan wells. By requiring owners and operators to close well sites as an automatic consequence of failure to comply with monitoring requirements, the NSPS and EG will incentivize owners and operators both to comply with monitoring requirements and to either produce or plug wells, rather than leaving them idled and unplugged or abandoning them to become orphan wells.

Response II-4-80: In the December 2022 Supplemental Proposal, the EPA solicited comments on potential additional provisions that could be added to the well closure provisions, including, for example, automatic consequences for missed monitoring reports, as a means of assuring that companies remain engaged with the site, including conducting monitoring, until all the wells at the site are properly closed. The EPA acknowledges comments provided in response to this solicitation, but EPA is not incorporating any automatic consequences in the final rule as this could be overly restrictive and not account for circumstances beyond the operator's control.

Comment: Commenter (2410-California Office of the Attorney General et al.) disagrees with comments stating EPA should consider adding restrictions on the amount of time that operators are allowed to idle wells and limit the number of idle wells that an individual owner or operator can hold.<sup>180</sup> For instance, under New Mexico's regulations, an operator is allowed to idle no more than a certain percentage of its wells: two wells or 50 percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less; five wells if the operator operates between 101 and 500 wells; seven wells if the operator operates between 501 and 1,000 wells; and 10 wells if the operator operates more than 1,000 wells.<sup>181</sup> New Mexico also requires operators to either properly plug and abandon a well or place the well in approved temporary abandonment after drilling operations have been suspended for 60 days, the well has been determined to be no longer usable for beneficial purposes, or the well has been inactive for one year; and limits the time allowed for approved temporary abandonment to five years.<sup>182</sup> The longer wells are allowed to remain idle, the greater potential that they will become orphan wells. Also, a high percentage of idle wells may indicate an increased vulnerability of the owner becoming insolvent and leaving orphan wells.

Response II-4-81: EPA acknowledges the comments. The final rule does not restrict the amount of time that operators are allowed to idle wells.

Comment: Commenter (2298-Pioneer Natural Resources USA, Inc.) notes in 60.5397b(l)(3) the proposal states that operators must update the well closure plan specified in paragraph (1)(1) of this section to include the video of the OGI survey demonstrating closure of all wells at the site, and in §60.5410b(k)(5) that operators should keep records as stated in §60.5420b(c)(14). The commenter does not understand the need for a video of the OGI survey for the well closure requirements, especially since videos are not required for routine OGI inspections for LDAR. Keeping this "video footage" for the required 5 years of NSPS requirements is not only difficult but almost impossible when it comes to data restraints for technology, downloads, data storage, etc. Therefore this requirement is infeasible and overly burdensome.

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<sup>180</sup> See Att. 21, IOGCC, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021 (detailing state regulatory strategies for addressing orphaned wells).

<sup>181</sup> 19.15.5 NMAC.

<sup>182</sup> 19.15.25 NMAC.

Commenter (2298-Pioneer Natural Resources USA, Inc.) strongly urges EPA to remove this OGI video requirement altogether and/or require it only for facilities required to comply with Appendix K where EPA has justified more extensive monitoring, recordkeeping, and reporting requirements.

Response II-4-82: The EPA disagrees with the commenter and is maintaining the requirement in the final rule to include the video of the OGI survey in the well closure plan demonstrating closure of all wells at the site. This requirement will allow EPA and state agencies the ability to review the OGI survey video and confirm compliance with the rule.

The EPA does not believe that the standard requirement of maintaining records for 5 years is an onerous requirement and the rule includes alternatives to maintain records, and any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

Comment: Commenters (2177-Ute Indian Tribe, 2271-Private Citizen, 2410-California Office of the Attorney General et al.) support EPA's proposal to require reporting, through the annual report, of any changes in ownership at individual well sites. The commenter agrees that such a requirement will help prevent well sites from becoming orphaned by providing clarity as to who the responsible owners and operators are until the site is plugged and closed and LDAR is no longer required.

Response II-4-83: The EPA acknowledges supportive comments.

Comment: Commenter (2433-EDF et al) recommends that EPA require the final well closure plan to be submitted 30 days prior to the cessation of production of any well located at the site. Public reporting should also occur when the well has been properly plugged so regulators can verify closure and so EPA can de-list the site.

Response II-4-84: EPA is finalizing the well closure requirements, including the requirements for the well closure plan in §60.5397b(l)(1) as proposed, which specifies submitting the well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site. The EPA disagrees the well closure plan should be submitted prior to the end of production and believes maintaining flexibility in the submittal timing is appropriate.

#### **4.1.7 Other**

Comment: Various commenters provided input regarding the treatment of plugged and abandoned wells. These comments are summarized below.

Commenters (2039-Citizens to Preserve Ligonier Valley, Inc., 2199-Rocky Mountain Farmers Union, 2209-Public Land Solutions, 2212-On behalf of the Union of Concerned Scientists, 2217-Religious Action Center of Reform Judaism, 2335-Loren Karro, 2352-Environment Texas Research and Policy Center, 2408-Colorado Local Government Coalition, 2414, 2453-Carbon Mapper and RMI, 2425-Taxpayers for Common Sense (TCS), 2447-Clean Air for the Long Haul, 2448-Project Canary, PBC) suggest that plugged and abandoned wells be intermittently monitored to be sure that the plugging actions taken are sufficient to eliminate oil and gas leakage in perpetuity.

Commenters (2219-WOGCC, 2401-State of Wyoming) add the well closure section of EPA's proposed rule states that requiring well closure plans would address concerns regarding continuing emissions from orphaned wells and idled wells. Mentioning orphan wells here seems to imply that EPA would implement these well closure requirements on orphan wells. EPA has no authority over how the commenter manages its orphan well program and no authority to require commenters (2219-WOGCC, 2401-State of Wyoming) to implement these well closure requirements. While commenter (2219-WOGCC) requests EPA strike the entire section on well closure since it is outside of EPA's authority, EPA should also recognize it cannot require the states to implement any of this program on orphan wells and should remove any reference to orphan wells in this section.

Commenter (2223-Texas Alliance of Energy Producers) notes that abandoned and plugged wells are no longer accessible by operators in Texas. This is because the operator retains zero access rights once a well has been properly plugged and reported as abandoned to the state regulator. An operator, if EPA's proposal was adopted, would be forced to maintain existing rights to the well and under existing law would be forced to delay proper and necessary plugging operations. Here, EPA risks contaminating groundwater or surface soils in the name of air monitoring which is completely contrary to the overall goals of improving the air and water subject to EPA's jurisdiction.

Commenter (2226-Thermo Fisher Scientific) agrees with the EPA's proposed requirement to monitor abandoned and unplugged oil wells using OGI. However, the commenter encourages the EPA to conduct additional monitoring with technology beyond OGI. In certain circumstances, OGI can miss emissions due to operator error, or emissions may change after the survey. The commenter recommends using more acute handheld measurement devices (like Thermo Fisher's Toxic Vapor Analyzer 2020) in conjunction with the OGI to ensure emissions are appropriately accounted for. Additionally, the EPA should consider continuous emissions monitoring technology for abandoned and unplugged wells of high risk for gas leaks.

Commenters (2363-CEMC, 2448-Project Canary, PBC) believe operators should monitor pre-plugging and document any flow rate and concentration to determine a calculated emissions rate (grams per hour) using best available technology, such as a high-fidelity (1 gram/hour or lower), ground-based technique and instrumentation and conducted by a person trained in that measurement methodology. For this level of fidelity, OGI is not sensitive enough to conduct a detect/non-detect for these wells. After a well is plugged, the operator should monitor the well to confirm that the plug was successful and there are no longer emissions present, whether through the wellbore itself or nearby soil. Data measurement and quality assurance criteria should meet the federal program information needs for methane measurement and allow for aggregation. Documentation should include weather/environmental conditions under which the measurement occurred, location of the detection, and the maximum emissions concentration recorded in ppm. It is recommended that multiple measurements be recorded before and after plugging the well to verify the effectiveness of the measurement.

Commenter (2392-Earthjustice et al.) states the median cost for decommissioning an orphaned well is roughly \$20,000 for plugging, and \$76,000 when surface reclamation is also required.<sup>183</sup>

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<sup>183</sup> Daniel Raimi et al., Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Cost Estimates and Cost Drivers, 55 *Env't Sci. & Tech.* 10224, 10224 (2021), <https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c02234>.

Because these wells have no solvent owner on record, the burden of remediation falls on local, state, and federal governments and diverts resources that could otherwise be used for the public good.

Commenter (2392-Earthjustice et al.) continues, the adverse economic impact imposed by remediation of orphaned and abandoned wells is disparately distributed. States with the largest Latine populations also have significant concentrations of orphaned and abandoned wells. For instance, the populations of California and Texas are both approximately 39% Latine<sup>184</sup> and these two states had 5,063 and 7,151 known orphaned wells in 2022, respectively.<sup>185</sup> And of the nearly 9 million people in the United States living within one mile of one of these wells, approximately 2.5 million are Latine.<sup>186</sup> In Pennsylvania, the state with the largest number of orphaned and abandoned wells, wells are concentrated in rural and low-income areas.<sup>187</sup>

Commenter (2392-Earthjustice et al.) adds research has repeatedly identified a link between proximity to abandoned wells and declining values of nearby property. A recent study in southwest Pennsylvania found that, over fifty years, the two acres around orphaned wells had approximately half as much development as the area around plugged wells.<sup>188</sup> The study further found that “the typical unplugged well leads nearby properties to have a market value 12% less than properties near plugged wells,” resulting in wide-ranging impacts on local economic development and revenue raising for schools and basic municipal maintenance.<sup>189</sup> A similar study conducted in Colorado found that “shale development negatively impacts house prices,” and that merely having a well in sight of a house reduces its value by approximately \$3,000.<sup>190</sup> Because oil and gas wells are disproportionately located in and near low-income communities and communities of color, as discussed above, these communities are left to bear the economic burden of this infrastructure.

Response II-4-85: In response to comments on the November 2021 Proposal, the EPA did not propose any requirements for these sources in the December 2022 Supplemental Proposal. The

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<sup>184</sup> Am. Counts Staff, U.S. Census Bureau, California 2020 Census (Aug. 25, 2021), <https://www.census.gov/library/stories/state-by-state/california-population-change-between-census-decade.html>; Am. Counts Staff, U.S. Census Bureau, Texas 2020 Census (Aug. 25, 2021), <https://www.census.gov/library/stories/state-by-state/texas-population-change-between-census-decade.html>.

<sup>185</sup> Env’t Def. Fund, Mapping Orphan Wells in California at 1 (2022), [https://www.edf.org/sites/default/files/2022-11/EDF\\_FactSheet\\_CA.pdf](https://www.edf.org/sites/default/files/2022-11/EDF_FactSheet_CA.pdf); Env’t Def. Fund, Mapping Orphan Wells in Texas at 1 (2022), [https://www.edf.org/sites/default/files/2022-11/EDF\\_FactSheet\\_TX.pdf](https://www.edf.org/sites/default/files/2022-11/EDF_FactSheet_TX.pdf).

<sup>186</sup> GreenLatinos et al., Latino Climate Justice Framework at 15 (2022), <https://www.lcjf.greenlatinos.org/>.

<sup>187</sup> Bobby Magill, Billions Spent on Abandoned Oil Wells Scratch at Ignored Problem, Bloomberg Law (July 25, 2022, 3:30 AM), <https://news.bloomberglaw.com/environment-and-energy/states-will-get-billions-to-plug-orphan-oil-wells-is-it-enough>.

<sup>188</sup> Max Harleman and Jeremy Weber, Other Voices: Plugging Abandoned Wells Boosts Local Economies, Pittsburgh Post-Gazette (July 18, 2021, 10:00 PM), <https://www.post-gazette.com/opinion/Op-Ed/2021/07/18/Other-Voices-Plugging-abandoned-wells-boosts-local-economies/stories/202107180012> [hereinafter “Harleman & Weber, Plugging Abandoned Wells”]; Max Harleman et al., Environmental Hazards and Local Investment: A Half-Century of Evidence from Abandoned Oil and Gas Wells, 9 J. Ass’n Env’t & Res. Econ. (2002), <https://www.journals.uchicago.edu/doi/epdf/10.1086/719383> [hereinafter “Harleman et al., Environmental Hazards and Local Investments”].

<sup>189</sup> Harleman et al., Environmental Hazards and Local Investments, supra n.80, at 749; Harleman & Weber, Plugging Abandoned Wells, supra n.80.

<sup>190</sup> Heather Stephens and Amanda Weinstein, Household Valuation of Energy Development in Amenity-Rich Regions, 50 Growth and Change 1375, 1375 (2019), <https://onlinelibrary.wiley.com/doi/abs/10.1111/grow.12335>.



EPA is finalizing well closure requirements, but no requirements are being finalized for abandoned wells, unplugged wells, or wells that are plugged insufficiently.

Comment: Commenter (2196-Roy Massengale) notes a probable citation error/typo. The cited section should say (g)(1)(iii)(A) through (C).

§60.5397b(g)(1)(iii)(D): Two or more pieces of major production and processing equipment not specified in paragraphs (g)(1)(ii)(A) through (C).

Response II-4-86: The commenter is correct. The EPA has corrected the citation in the final regulatory text.

Comment: Commenter (2298-Pioneer Natural Resources USA, Inc) designs multi-well pads that direct the flow into large, centralized tank batteries. Wells are not drilled on multi-well pads all at once but rather wells are added to existing pads over time. Therefore, the commenter has assessed that it will have both NSPS OOOOa and NSPS OOOOb affected wells on the same pads. Due to difficulty this could present with the different monitoring requirements on the same pads, the commenter recommends that EPA align the monitoring requirements/or wells on the same pad. Similar to the approach EPA took for pneumatic controllers in §60.5365b(d)(1),<sup>191</sup> it would streamline monitoring if one well on the pad is subject to NSPS OOOOb, that all of the wells on the pad become subject to NSPS OOOOb - the result will be less miles driven and emissions generated.

Response II-4-87: The rule specifies at §60.5365b(i)(1)(i) that if a new well is drilled at an existing well site this would be considered a modification. The well site would therefore be subject to NSPS OOOOb if the modification occurred after December 6, 2022. Similarly, if a new well is drilled at an existing centralized production facility, this would also be considered a modification, and the centralized production facility would be subject to NSPS OOOOb if the modification occurred after December 6, 2022.

Comment: Commenter (2248-NDPC) is requesting clarification on acceptable methodology for determining a site's fugitive emissions. EPA should allow for any state-approved and/or industry best practices to quantify fugitive emissions.

Response II-4-88: The EPA is uncertain what the commenter is requesting. The fugitive emissions monitoring requirements in the December 2022 Supplemental Proposal were based on the equipment located at the well site. The final rule maintains this equipment-based approach, which does not require the quantification of fugitive emissions.

Comment: Commenter (2248-NDPC) wants to remind the EPA that LDAR programs do generate emissions, because the OGI inspectors must drive from site to site. The commenter believes the requirement to inspect wellhead only sites, and sites where wells have been abandoned, vehicle emissions will outweigh any benefit the program may identify.

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<sup>191</sup> " ... in addition to the definition in §60.14, a modification occurs when the number of pneumatic controllers at a site is increased by one or more."

Response II-4-89: The EPA acknowledges the commenter’s concerns regarding secondary impacts. As mentioned in the November 2021 proposal preamble and the 2021 Proposal TSD, there are no secondary gaseous pollutant emissions or wastewater generated during the monitoring and repair of fugitive emissions components. Emissions would be generated during travel to or from sites during inspections and surveys. The emissions generated by that activity was presented in section 5.5.3 of the 2021 Proposal TSD.<sup>192</sup>

Comment: Commenter (2428-API) notes state rules, including New Mexico<sup>193</sup> and Colorado<sup>194</sup>, exempt depressurized equipment<sup>195</sup> from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

Response II-4-90: The EPA agrees that the periodic fugitive emission monitoring should be conducted while the facility is operating such that there is a potential for emissions from fugitive emission components. Thus, if a site is down for maintenance when periodic monitoring was originally planned to occur, the periodic monitoring should be rescheduled for a time when the facility is operating. However, it appears the commenter is suggesting revisions to exclude “depressurized” equipment at an otherwise operating facility. The EPA believes this will increase burden rather than decrease burden. Monitoring must be conducted according to the monitoring plan, which identifies all fugitive emission components to be monitored. To effectively exclude one piece of equipment, the facility would need to continually revise its monitoring plan to track the fugitive emission components required to be monitored during changes in operation. For example, a compressor station may have four compressors, three operating compressors and one depressurized compressor. The compressors are commonly cycled so maintenance or other activities can be performed on the additional “fourth” compressor. Once an OGI camera operator is on site, it takes little time to monitor all four compressors additional piece of equipment; however, we expect it will take significant additional time to revise the monitoring plan based on constantly changing operations and the compressors are cycled in and out of service. The EPA notes that nothing in the rule prevents the owner or operator of a site to revise its monitoring plan. If a well is shut-in for a prolonged period, the monitoring plan can be revised to identify the fugitive emission components that must be monitored (those with a potential for VOC or methane emissions) during the shut-in. Thus, there are already provisions in the rule to allow facilities to exclude equipment that is no longer in service because they no longer meet the definition of fugitive emission component from their monitoring plan. However, we are not requiring facilities to update their monitoring plans each and every time a piece of equipment is depressurized.

Comment: Commenter (2211-Lambda Energy Resources) states many wells in the Michigan basin operate on vacuum from the wellhead to the sales point. Lambda’s wells operating on vacuum have continuous monitoring for oxygen at the sales point which would indicate a leak

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<sup>192</sup> See November 2021 TSD at Document ID No. EPA–HQ–OAR–2021–0317–0166.

<sup>193</sup> 20.2.50.116.C(9) NMAC.

<sup>194</sup> <https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view>.

<sup>195</sup> The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

into the system, and in order to meet regulatory and third-party pipeline quality specifications. Commenter believes EPA should exempt from fugitive emissions monitoring those wells operating on a vacuum, since a well on vacuum by definition cannot leak to the atmosphere.

Response II-4-91: Fugitive emissions component is defined beginning with “... any component that has the potential to emit fugitive emissions of methane or VOC...” Monitoring must be conducted on all “fugitive emission components,” but components on equipment continuously operated under sufficient vacuum such that any “leaks” that occur would leak gas into the equipment rather than to the atmosphere would not meet this definition. We believe the requirements of the fugitive emission program are clear and the facility is free to develop a monitoring plan that includes all fugitive emission components, but excludes components that do not have the potential to emit VOC or methane.

## 4.2 NSPS OOOOb for Compressor Stations

### 4.2.1 Proposed BSER

Comment: Commenters (2392-Earthjustice et al., 2433-EDF et al.) urge EPA to require bimonthly OGI at all compressor stations.

Commenter (2433-EDF et al) indicate that compressor stations contain large numbers of fugitive emissions components and are a major known source of emissions.<sup>196</sup> For the reasons articulated in their initial comments and based on their revised cost-effectiveness analysis, the commenter urges EPA to require bimonthly OGI at all compressor stations.<sup>197</sup> Bimonthly monitoring at compressor stations is well within EPA’s cost-effectiveness range and should be required to ensure greater emission reductions from these large sources.<sup>198</sup>

Response II-4-92: EPA disagrees that bimonthly OGI should be required at all compressor stations. With regard to the frequency of OGI surveys, EPA conducted an in-depth analysis for the November 2021 Proposal that evaluated the emissions reductions and costs associated with more frequent OGI monitoring options for all types of compressor stations. That analysis was presented in the 2021 TSD. As discussed in Section XII.A.b of the November 2021 Proposal preamble, EPA determined that more frequent OGI monitoring than quarterly was not cost-effective, and for that reason maintained quarterly OGI monitoring. Consistent with that conclusion, EPA proposed to retain a quarterly OGI monitoring frequency in the proposed December 2022 regulation while adding requirements to conduct monthly AVO monitoring at compressor stations and that any fugitive emissions detected via AVO would be subject to repair in response to comments.<sup>199</sup>

While emissions reductions associated with bimonthly OGI were not directly analyzed for compressor stations, EPA did calculate emissions reductions for bimonthly OGI and the

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<sup>196</sup> See, e.g., Evan Sherwin et al., Quantifying oil and natural gas system emissions using one million aerial site measurements, Preprint (2023) <https://www.researchsquare.com/article/rs-2406848/v1> (finding that emissions from midstream facilities can make up 50 percent of the total in certain basins).

<sup>197</sup> See EPA Docket No. EPA-HQ-OAR-2021-0317-0844, at 112–15.

<sup>198</sup> Daniel Zimmerle et al., Methane Emissions from Gathering Compressor Stations in the U.S., 54 Env’t. Sci. Tech. 7552 (2020), <https://pubs.acs.org/doi/10.1021/acs.est.0c00516>.

<sup>199</sup> See 87 FR 74739 (December 6, 2022), section IV.A.2.

combination of quarterly OGI and monthly AVO for large well sites; that analysis is presented in the Final TSD. In the large well sites analysis, the combination of quarterly OGI and monthly AVO achieved greater emissions reductions than bimonthly OGI. EPA believes that qualitatively, the same trend observed for large well sites is likely to be true for compressor stations, supporting that the finalized provision is the BSER.

With regard to cost-effectiveness determinations, CAA section 111 requires that NSPS “reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.” The EPA considered these statutory factors in promulgating the final standards, including the fugitive emissions standards for compressor stations. One tool that the EPA has consistently used in evaluating control costs is the cost-effectiveness of available control options (i.e., the cost of reducing a ton of a specific pollutant per year). This this final rule is no exception. EPA considered total and incremental cost-effectiveness when determining the BSER and, in this case, determined that the BSER was quarterly OGI rather than monthly OGI due to total and incremental costs being considered cost effective and the small fraction of additional reductions realized at monthly monitoring; while the total cost of monthly OGI was considered cost-effective, the incremental cost of monthly OGI was not considered cost-effective. Because monthly OGI was only projected to achieve minor emissions reductions over quarterly OGI at over double the projected annual cost and the incremental cost was projected to be greater than the social cost of methane, quarterly OGI was determined to be the BSER over monthly OGI. The combination of quarterly OGI and monthly AVO is also expected to result in additional emissions reductions at no additional cost; EPA notes that no commenter disputed or otherwise questioned the low cost of AVO monitoring which EPA relied upon in the December 2022 Supplemental Proposal.

Regarding the cost-effectiveness numbers determined by other entities, the fact that states such as Colorado and New Mexico may determine different costs for similar standards in their states does not mean that the costs are the same on a national scale, or that standards that may be appropriate for facilities in any given state are appropriate on a national scale because each state only represents a fraction of the sector and costs may vary by state. Additionally, neither the cost estimates done for state regulations nor requirements of state regulations about compressor station fugitives are uniform nationally, highlighting differences in cost calculation methods and what is considered cost effective by different entities.

Comment: Commenter (2211-Lambda Energy Resources) believes it is overly burdensome and unnecessary to require monthly AVO and quarterly OGI or Method 21 monitoring and record keeping for compressor stations. Existing equipment and monitoring methods have proven effective and have minimized emissions, and Lambda believes a baseline threshold for low volume compressor stations and periodic AVO inspections and documentation would effectively achieve the goals of the proposed requirements.

Response II-4-93: The EPA disagrees that it is overly burdensome and unnecessary to require monthly AVO and quarterly OGI or Method 21 record keeping for compressor stations. As explained in the December 2022 Supplemental Proposal (87 FR 74739), regular AVO inspections at compressor stations can be conducted by any staff at the site without the need for any special expertise. In fact, AVO inspection was added in the December 2022 Supplemental

Proposal in response to recommendations by some commenters<sup>200 201</sup> on the November 2021 Proposal recommending AVO as a low-cost method that is effective at identifying emissions, even for small-company compressor stations. The commenters specifically noted that even though small-company compressor stations are not manned 24 hours per day, they are visited weekly, if not daily. The EPA found the comments persuasive and did not see a need to confirm the commenters' assertions by conducting its own cost analysis for conducting monthly AVO inspections for compressor stations. The EPA notes that no commenter disputed or otherwise questioned the comments described above regarding the low cost of AVO monitoring, which the EPA relied upon in its December 2022 Supplemental Proposal. With regard to the comment suggesting that OGI monitoring is unnecessary because AVO surveys during these frequent visits would effectively achieve the EPA's emission reduction goals, the EPA disagrees that AVO surveys alone (i.e., without quarterly OGI monitoring) qualify as the BSER because OGI is needed to detect fugitive emissions that are not detectable by AVO. In addition, the EPA received no information that caused it to change its assessment that quarterly OGI at compressor stations is not cost-effective. Accordingly, the EPA is finalizing its determination that monthly AVO monitoring and quarterly OGI monitoring, in combination with repair requirements, represents the BSER for fugitive emissions components at both new and existing compressor stations. The commenter did not provide any additional data demonstrating that quarterly monitoring for compressor stations is overly burdensome.

#### **4.2.2 Delay of Repair for Lack of Availability of Parts**

Comment: Commenter (2483-INGAA) states the proposed delay of repair relief for lack of availability of parts for valves provided to onshore natural gas processing plants should also be given to compressor stations. In addition, that delay of repair relief should be expanded to include equipment beyond valves, particularly at existing sources. The equipment used for gas transmission is highly specialized and is not always readily available or in stock. In some cases, the parts need to be fabricated, which can take, for example, four to five months for smaller station valves (e.g., 8-12 inch lines) and 10 months or longer for large valves; larger, unique parts that require fabrication may take more than a year.

Commenter (2483-Interstate Natural Gas Association of America (INGAA)) has long advocated for EPA to allow for delay of repair due to the lack of availability of parts. The commenter has repeatedly expressed concern that any emission guideline for existing compressor stations needs to contain a delay of repair provision for parts availability to avoid reliability impacts to customers and system disruptions.<sup>202</sup> The commenter felt encouraged when EPA sought comment on several specific issues related to a replacement part delay of repair provision in the 2021 proposal for *compressor stations*.<sup>203</sup> Specifically, EPA asked for:

[D]ata to better understand the breadth of this issue with replacement parts for existing compressor stations. Additionally, we are soliciting comment on whether 30 days following receipt of the replacement part is appropriate for completing delayed repairs at existing *compressor stations*, whether there should be any limit on delays in repairs under

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<sup>200</sup> EPA Docket No. EPA-HQ-OAR-2021-0317-0585.

<sup>201</sup> EPA Docket No. EPA-HQ-OAR-2021-0317-0814.

<sup>202</sup> EPA Docket No. EPA-HQ-OAR-2021-1391, INGAA Comments on the 2021 Partial Proposal at 9.

<sup>203</sup> 86 Fed. Reg. at 63,174 (noting "for compressor stations, we are soliciting comment on delayed repairs by existing sources when parts are not readily available and must be special ordered").

these circumstances, and whether this compliance flexibility should be limited or disallowed based on the severity of the leak to be repaired.<sup>204</sup>

Commenter (2483-INGAA) provided such data, giving EPA further information on the importance of delay of repair, discussing the types of equipment for which a delay in availability can occur, and providing in-depth information on valves and the dozens of components that make up a valve.<sup>205</sup> Despite providing this information and meeting with EPA numerous times to discuss the importance of this issue, it does not appear that EPA is providing delay of repair related to parts availability to compressor stations. The Agency is providing such relief, however, to valves at onshore natural gas processing plants.<sup>206</sup> The commenter hopes that omitting this relief from the section of the proposed regulatory text regarding existing compressor stations may be an oversight or error on the part of EPA given that it had specifically solicited comment in the 2021 Partial Proposal on providing delay of repair to compressor stations.

If this is not an error, then commenter (2483-INGAA) respectfully asks EPA to reconsider providing the relief that it proposes to give to onshore natural gas processing plants to compressor stations as well. There is no discussion at all in the preamble about delay of repair due to lack of availability of parts, and thus it is impossible to understand whether this is indeed a mistake or whether EPA actually intends to provide this important relief to natural gas processing plants but not compressor stations.

Commenter (2483-INGAA) stresses delay of repair due to lack of availability of parts is needed to ensure reliability of the natural gas system, which is of paramount importance. Operators routinely need to manage various challenges to meet demand. Adopting a rule that would require or prolong equipment or station shutdowns while awaiting parts would inhibit operators' ability to keep the system operating reliably and to meet their contractual commitments. Potential reliability disruptions are not limited to certain seasons such as winter or summer when natural gas demand may be higher. Many natural gas transmission pipelines operate at high capacity year-round, and there is little redundancy in the transportation chain. Some compressor stations are located logistically where their operations are important for reliability, operate year-round, and are difficult to take out of service without impacting an operator's ability to serve its customers. As more power plants are fueled by natural gas, and they need to run during the summer and other periods of time when pipelines historically performed scheduled maintenance on equipment, it may become more challenging to have compressor stations out of service and continue to meet electric demand. Regulations should not be written in a manner that creates a tension between complying with an environmental regulatory requirement and meeting contractual commitments governed by Federal Energy Regulatory Commission tariffs. While it is imperative to comply with environmental regulations intended to minimize the impact of operations to the environment, failing to meet contractual delivery obligations could also create health and safety risks (e.g., loss of home heating during the wintertime, loss of natural gas

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<sup>204</sup> [Id.] (emphasis added).

<sup>205</sup> EPA Docket No. EPA-HQ-OAR-0317-1391, INGAA Comments on the 2021 Partial Proposal at 9-15.

<sup>206</sup> Proposed 40 C.F.R. §§ 60.5400b(h)(6)(iv), 60.5400c(h)(6)(iv). INGAA notes that the text of §§ 60.5400b(h)(6)(iv) and 60.5400c(h)(6)(iv) is identical to delay of repair relief provided for the synthetic organic chemicals manufacturing industry in Subpart VVa (other than Subpart VVa specifying that delay of repair "will be" allowed if certain conditions are met and § 60.5400c(h)(6)(iv) specifying that delay of repair "is" allowed if those same conditions are met). [Compare] 40 C.F.R. § 60.482-9a(e) [with] Proposed 40 C.F.R. §§ 60.5400b(h)(6)(iv), 60.5400c(h)(6)(iv).

supplied to power plants during hot summer months when there is an increased demand for electricity to run air conditioning, etc.) unless EPA provides for reasonable delay of repair provisions as it did with onshore natural gas processing plants.

Commenter (2483-INGAA) continues, if the omission of delay of repair provisions for compressor stations is not a mistake, it is impossible to understand EPA's rationale in providing this relief to one subcategory of sources (onshore natural gas processing plants) and not another (particularly one that has been asking for this relief for a long time). Treating these subcategories differently without explanation is arbitrary and capricious. There is no legitimate reason for EPA to conclude that onshore natural gas processing plants are somehow more unique and warrant different treatment than other sectors. Both compressor stations and natural gas processing plants include an array of various size (some very large), high-pressure gas valves where parts and/or replacement may require special machining, valve build, and other special circumstances. In fact, things may be more variable for compressor stations than for gas processing plants in some cases.

Commenter (2483-INGAA) provides the example, larger and older compressor stations, which will be subject to OOOOc, are probably more likely to have an array of unique valves due to how many existing stations were expanded over time, which led to there being large valves associated with different compressor sizes and types (and different vintages). For example, a larger station that was initially built 50 to 70 years ago may have started with a couple of units and expanded to include 10 or more compressors (or even more than 20 compressors in some cases) with add-ons occurring incrementally over multiple decades. As a result, a compressor station can have compressor houses with different size and vintage compressors, reciprocal, and centrifugal units. All of this equipment will have multiple valves, and each expansion project will very likely have unique equipment (compressors, drivers, valving, etc.). The array of large valves that require special service for parts or replacement (dozens of different sizes and types in some cases) for compressor stations may thus be more complicated than at some gas processing plants. The commenter submitted comprehensive comments on this, including photographs, in their Appendix B on Pre-Rulemaking Request for Information.<sup>207</sup>

Commenter (2483-INGAA) asks that the following regulatory text (which is identical to the delay of repair due to parts availability given to onshore natural gas processing plants) should also be provided for valves at compressor stations:

Proposed Regulatory Text for Valves at Compressor Stations – §§ 60.5397b(h)(4), 60.5397c(h)(4)<sup>208</sup> (additions are underlined; deletions are in strike-through):

(4) Delay of repair beyond a compressor station shutdown for maintenance is allowed for a valve, if valve assembly replacement is necessary during the compressor station shutdown for maintenance, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay

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<sup>207</sup> EPA Docket No. EPA-HQ-OAR-0317-2483, INGAA Comments on Pre-Rulemaking Request for Information at 12-21 (App. B) (attached as Attachment 4 to Attachment A of these Comments).

<sup>208</sup> The currently proposed 40 C.F.R. §§ 60.5397b(h)(4) and 60.5397c(h)(4) would each need to be renumbered as (h)(5). Please note that broader proposed regulatory text is also provided for EPA to consider in Section V.B that would cover more parts than just valves. If that proposed regulatory text is adopted, then this proposed regulatory text should be ignored.

of repair beyond the next compressor station shutdown for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance.

Response II-4-94: With regard to delay of repair provision related to parts unavailability, EPA considered the information submitted by the commenters and is including provisions to allow the delay of repair due to the lack of availability of parts in some circumstances. Section X.A.2 of the preamble to the final rule details the fugitive emission standards concerning delay of repair due to parts unavailability, and section XI.A.2.b of the preamble to the final rule details EPA's rationale and reasoning regarding delay of repair due to parts unavailability. In response to comments, EPA is allowing delay of repair that requires replacement but the replacement cannot be acquired and installed within the repair timeline due to replacement valve supplies that have been sufficiently stocked but are depleted at the time of repair, similar to the provisions for valves at onshore natural gas processing plants. EPA concludes that well sites and compressor stations face some of the same valve assembly supply constraints as onshore natural gas processing plants and that operators can ensure timely ordering of replacement fugitive components or parts thereof but cannot control replacement delivery timelines. Thus, EPA is including similar delay of repair provisions for valve assembly supplies that had been sufficiently stocked but are depleted at the time of the required repair for wellsite and compressor station fugitives as for onshore natural gas processing plants in this rule. The final fugitive emissions standards for well sites and compressor stations under NSPS OOOOb (and presumptive standards under EG OOOOc) allow delay of repair due to depletion of supplies for valves only. This is consistent with the standards for onshore natural gas processing plants, which have provided such allowance for *valves only* since the standards were first promulgated in 1985, and the EPA has not received information showing difficulty of repair due to well stocked supplies of other fugitive emissions components or parts thereof that were depleted before repair could be completed.

Comment: Commenter (2483-INGAA) argues EPA should provide delay of repair for other equipment beyond valves. Equipment utilized for gas transmission is highly specialized and is made to stringent engineering specifications. The parts necessary to repair a leak are not always readily available or in stock. Not only do parts come in various sizes, but parts are not interchangeable between different manufacturers, models, or even different vintages of the same equipment. Some existing source compressors may be more than 50 years old, and compressors have changed over time. If a part breaks on an older piece of equipment, the comparable part that is used for new compressors may not be the right size or configuration for that older equipment. For example, the specifications of an older compressor valve might not be standard, the system associated with an older unit might have additional connections for recirculation piping, or there might be additional changes that the operator needs to make to that system to address other regulatory requirements, such as PHMSA regulations. In such cases, the appropriate parts for that equipment will need to be custom ordered and/or manufactured, and it may take several months to fabricate such parts.

Commenter (2483-INGAA) continues, the delivery time on receiving such equipment can also be prolonged because some parts are manufactured overseas. As has been seen in recent months, supply chain delays have lengthened the times for overseas products to be delivered, and even if a part is manufactured in the United States, it could be affected by supply chain delays because the materials needed to manufacture the part are delayed. While operators can control the



ordering of needed parts and can ensure this is done in a timely fashion, they cannot control how quickly that part will arrive. System reliability should not suffer because of supply chain delays.

Commenter (2483-INGAA) states the occurrence of such situations where the need for replacement parts that are not readily available and for which a delay of repair allowance will be appropriate is nevertheless likely to be a relatively rare occurrence, and thus the emissions associated with these occurrences are therefore likely to be small. The commenter's members currently report that the typical lead-times for smaller valves (i.e., those that are between 8 and 12 inches) are in the neighborhood of 16 to 20 weeks. The lead times for larger valves are generally 20 to 40 weeks, with large bore valves taking approximately 40 weeks and new valve actuators taking approximately 20 to 24 weeks. The need for parts with unique design requirements is rare, but because these parts must be special ordered, it can typically take up to 12 months to obtain them. All lead times are subject to change based on market conditions.

Commenter (2483-INGAA) adds an analysis of the commenter's members' affected sources reveals that there are over 20 different engine manufacturers and over 100 different models, each with their own model-specific parts. Further, these various engines span a wide range of vintages, such that even parts from a single supplier can vary significantly from model year to model year. Likewise, there are several different turbine manufacturers and dozens of different turbine models. The complications arising from different model year equipment requiring different parts applies with equal force to turbines. All of this equipment, moreover, is itself composed of many unique sub-assemblies, potentially comprising thousands of sub-components for each facility. Any one of these thousands of components and subcomponents could be required to repair a leak and need to be replaced.

Commenter (2483-INGAA) notes Appendix B to INGAA's Pre-Rulemaking Comments helps to further explain the enormity of the challenge posed by part availability for existing compressor stations by providing examples of the types of equipment and potential leak sources that are most likely at compressor stations. As Appendix B explains, a typical compressor house will have multiple compressors within the building and a compressor station may have several compressor houses.<sup>209</sup> The appendix provides photographs and diagrams of just some of the key equipment located in these compressor houses to illustrate the scale and breadth of the issue for the industry. The examples reviewed in Appendix B begin with integral reciprocating compressors, which are common in gas transmission.<sup>210</sup> These units include flanges, cover plates, and bolted surfaces encasing natural gas, and each of these components is a potential leak source and piece of equipment that may need to be replaced.<sup>211</sup> Looking at a cross-section of the integral reciprocating compressor itself, Appendix B further identifies the engine fuel system and compressors, and the flanges and cover plates associated with the compressor variable valve pockets and distance piece as additional potential leak sources.<sup>212</sup>

Commenter (2483-INGAA) continues, looking more in-depth into just one category of these potential leak sources – valves – the appendix explains that each type of valve is itself made up of dozens of components, “including: the valve stem packing, grease nipples, bleed ports, valve

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<sup>209</sup> EPA Docket No. EPA-HQ-OAR-0317-2483, INGAA Pre-Rulemaking Comments, App. B at 13 (attached as Attachment 4 to Attachment A of these Comments).

<sup>210</sup> [Id.]

<sup>211</sup> [Id.] at 15.

<sup>212</sup> [Id.] at 16.

body seals (e.g., where the bonnet bolts to the valve body, retainer connections), packing guide, and any monitoring ports on the stem packing system.”<sup>213</sup> As explained above, and as further described in Appendix B, the number of these potential leak sources must be multiplied by the different sizes, manufacturers, and model years for the equipment in use at the source to fully appreciate the number of pieces of equipment that could require replacement and the enormity of the stockpile of spare parts that would be needed for each facility.

Commenter (2483-INGAA) states an argument often given against delay of repair for parts availability is that operators should keep an inventory of parts on hand. This argument simply does not understand the scope and scale of the issue. Given the number of engines and turbines and the considerable variation in design among manufacturers and across model years, it is not feasible for individual companies or facilities to stockpile every type and size valve or part that might be needed to repair a leak. An operator has no reasonable way to predict which parts will need to be replaced and when, particularly considering that the operator’s initial attempts to stop the leak using other repair methods may be successful. Moreover, these parts are very expensive, with larger valves costing in the range of \$50,000 to \$200,000.

Commenter (2483-INGAA) argues for the same reason and because of generally low demand for what are often relatively unique or uncommon parts, manufacturers cannot be expected to maintain an inventory of parts ready for rapid shipment when a facility discovers a part must be replaced. Maintaining such an inventory would have considerable tax and cash flow implications because the parts may never sell due to low demand. In addition, many parts have a shelf-life that limits the time they can remain in inventory, and an operator may question whether a part may have been sitting on the shelf for too long and is still good for use. In the commenter’s experience, manufacturers limit their inventory to items that move quickly or are more commonly required, which means there is not a ready inventory of expensive, unique, or parts for older equipment. Because it is not feasible to keep a complete stockpile of all possible equipment that may need to be replaced to address a leak, allowing a delay of repair to provide time for acquisition of replacement parts is necessary.

Commenter (2483-INGAA) concludes the number of parts that may potentially require replacement at any given facility is enormous, and the time needed to obtain some of these parts can be lengthy. The equipment used for gas transmission is highly specialized and is not always readily available or in stock. When parts need to be fabricated, it can take four to five months to obtain smaller station valves (e.g., 8-12 inch lines) and 10 months or longer for large valves; larger, unique parts that require fabrication may take more than a year. Given this, the only reasonable solution that preserves reliability of the gas supply is to include a delay of repair provision related to availability of all parts (not just valves) in OOOOb and OOOOc for compressor stations:

Proposed Regulatory Text for All Parts at Compressor Stations – §§ 60.5397b(h)(4), 60.5397c(h)(4)<sup>214</sup> (additions are underlined):

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<sup>213</sup> [Id.] at 18.

<sup>214</sup> The currently proposed 40 C.F.R. §§ 60.5397b(h)(4) and 60.5397c(h)(4) would each need to be renumbered as (h)(5).

(4) Delay of repair beyond a compressor station shutdown for maintenance is allowed for parts replacement, if the parts replacement is necessary during the compressor station shutdown for maintenance, parts supplies have been depleted, and parts supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next compressor station shutdown for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance.

Response II-4-95: With regard to delay of repair provision related to parts unavailability, EPA considered the information submitted by the commenters and is including provisions to allow the delay of repair due to the lack of availability of parts in some circumstances. Section X.A.2 of the preamble to the final rule details the fugitive emission standards concerning delay of repair due to parts unavailability, and section XI.A.2.b of the preamble to the final rule details EPA's rationale and reasoning regarding delay of repair due to parts unavailability. The comments on the November 2021 Proposal and December 2022 Supplemental Proposal also include supporting information on exceptional, infrequent circumstances where a replacement part requires custom fabrication. Specifically, the information includes insight into the quantity and variety of vintage equipment at compressor stations, the unlikelihood of manufacturers stocking replacement parts for vintage equipment and thus the need for custom fabrication of replacement supplies, and the timeline for fabrication and delivery of custom supplies. Recent examples of extensive supply chain delays have highlighted that a delay of repair may be needed for circumstances beyond an owner or operator's control.<sup>215</sup> In light of the information on the challenges and the time needed to acquire parts that require custom fabrication and the current supply chain issue, we are including in the final NSPS OOOOb and the model rule in EG OOOOc provisions for delay of repair where replacement is required and the replacement fugitive emissions component or a part thereof requires custom fabrication. This provision allows for delay of repair for parts beyond valves that require custom fabrication.

Comment: Commenter (2366-BHE) reiterates their January 2022 comments<sup>216</sup> and strongly recommends that EPA allow delay of repair (DoR) when parts are not available for all natural gas segments, and states that the allowance should not be limited to valves because other parts also may not be readily available. The commenter refers to detailed comments and example scenarios they provided in their January 2022 comments as well as comments provided by the Interstate Natural Gas Association of America (INGAA) in January 2022, on the same topic.<sup>217</sup> The commenter is concerned because EPA support documentation does not explain why processing is treated different than other natural gas industry segments. The commenter believes there is no legitimate reason for EPA to conclude that processing valves are somehow more unique and warrant different treatment than other natural gas industry segments. By way of example, the commenter states that both transmission compressor stations and processing plants include an array of various size, high pressure gas valves, including very large valves where parts and/or replacement may require special machining, valve build, etc. In fact, according to the commenter, due to the wide array of compressor drivers and compressors in transmission and

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<sup>215</sup> EPA Docket No. EPA-HQ-OAR-2021-0317-2483.

<sup>216</sup> Berkshire Hathaway Energy Company (BHE). Public Comments Re: Standards of Performance for New, Reconstructed and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110 (Nov. 15, 2021). January 21, 2022. EPA Docket ID EPA-HQ-OAR-2021-0782.

<sup>217</sup> EPA Docket No. EPA-HQ-OAR-2021-0317-1391.

due to different manufacturers, models, and vintage, there may be more unique, large legacy part types in transmission compressor stations than for processing plants. By way of example, the commenter states that larger and older compressor stations subject to EG OOOOc are probably *more* likely to have an array of large, unique valves because larger, existing stations were likely expanded over time. Thus, they note that there are large valves and compressor components associated with different compressor manufacturers, models, sizes, and vintages because incremental horsepower may have been added in several projects over multiple decades for a station originally constructed in the 1950s, and each would likely have unique equipment (compressors and drivers, valving etc.). The commenter contends that DoR due to parts availability is not unique to natural gas processing plants and should apply to all affected sectors [segments].

Similarly, the commenter (2366-BHE) suggests that these DoR provisions should apply to parts other than valves. By way of example, the commenter explains that compression includes an array of parts associated with the compressor driver (e.g., reciprocating engine or combustion turbine), the compressor, and associated valving, piping, and other processing equipment. They explain that a valve is one example of a part type that may not be available for repair or replacement, but other unique parts are also associated with other process equipment, such as the array of components associated with a large natural gas compressor. According to the commenter, the issues associated with the broad range of large valves for legacy equipment are just as relevant for legacy compressors and associated sub-components and large, unique legacy parts may need to be machined or more major components may need to be constructed. Thus, the commenter explains, DoR provisions due to unavailable parts should apply to any substantive part where the situation can be documented rather than only applying to valves. While the commenter believes that DoR due to these scenarios is not expected to be a common occurrence, they assert that it must be addressed in the regulations to ensure that equipment/facility shutdown is not mandated, and natural gas system reliability is not compromised, due to the unavailability of parts.

The commenter (2366-BHE) requests that the related regulatory text be revised to delete (or define) ambiguous terms such as “sufficiently stocked,” as it is unclear what amount of supplies EPA considers sufficient to meet this requirement. There is no discussion of this provision in the preamble, and clarification is required, according to the commenter. The commenter explains that many large and relatively unique parts cannot be stocked and may require special construction and/or machining. The term “sufficiently stocked” fails to recognize the scenarios explained in detail by this commenter and others, and neither the proposed rule text or preamble provide discussion of this term or acknowledge or explain scenarios where a parts inventory is infeasible, the commenter states.

Response II-4-96: As discussed in response to the previous response in this section, the EPA is including a delay of repair provision related to parts unavailability in the final rule for up to two years in specific circumstances. Provisions are included for valve assemblies and parts thereof and parts beyond valves that require custom fabrication. This provision is included in §60.5397b(h)(3)(ii) of the final rule.

With regard to removing the term “sufficiently stocked”, EPA disagrees that the term should be removed or specifically defined in the final rule because what may be considered “sufficient” may reasonably vary among parts, equipment counts, and facilities.

### **4.2.3 BSER Analysis/Emissions/Costs**

Comment: Commenter (2440-Nevada Nanotech Systems, Inc.) notes compared to state-of-the-art continuous monitoring systems, the proposed BSER of monthly AVO inspections and quarterly OGI inspections provides neither the greatest emissions reduction, nor does it provide the most economical solution. CP-CMS technology provides immediate detection of leaks and the greatest reduction in emissions for as little as \$4998 per year (Total Cost of Ownership). This price includes hardware installation, automated, continuous monitoring software and support, all required maintenance, automated leak notifications, visualization of the leak location via computer, tablet or phone and automated reporting of emission statistics. The commenter encourages the EPA to also allow continuous monitoring technology solutions as a BSER for compressor stations.

Response II-4-97: The EPA disagrees that continuous monitoring technology is the BSER for compressor stations because we do not have sufficient information to include this new but rapidly advancing technology in the BSER analysis; however, the EPA supports the use of continuous monitoring systems to detect fugitive emissions at compressor stations. The EPA is providing a pathway for owners and operators to utilize continuous monitoring technologies at compressor stations as part of the advanced methane detection technology provisions of the rule. Please see section X.B.2 of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (2283-Endeavor Energy Resources) states EPA should recognize that the proposed compressor station requirements will also have a direct economic impact on upstream producers. Under the Methane Proposal, compressor stations would be required to conduct monthly fugitive emissions inspections through AVO monitoring, coupled with quarterly monitoring using OGI or Method 21. While the commenter leases all compression from a third party, it is confident that the increased expense attributable to these new requirements will be passed on to Endeavor and other upstream producers, which risks further chilling domestic production. As a result, the commenter requests that EPA take these considerations into account in its economic analysis and work to also limit or simplify the monitoring burdens on compressor stations.

Response II-4-98: The EPA disagrees that it is appropriate to attribute costs for compressor station fugitives to upstream producers because the EPA does not consider it appropriate to attribute the costs of the same provision in multiple places in the same rulemaking and the costs have already been attributed to compressor station fugitives. With regard to limiting or simplifying the fugitive emission standards, EPA concludes that the BSER for compressor station fugitives is quarterly OGI and monthly AVO. Please see section 4.2.1 of this chapter for responses to similar comments related to the BSER.

## **4.3 EG OOOOc Fugitive Emissions from Well Sites and Centralized Production Facilities**

### **4.3.1 General**

Comment: Several commenters (1583-ODEQ, 2200-NuEnergy Operating Inc., 2211-Lambda Energy Resources, 2244-Private Citizen, 2248-NDPC, 2393-OSEE) express specific concerns

regarding the proposed requirements for existing sources under EG OOOOc and argue that the same fugitive emissions monitoring should not apply to existing sources as those for new sources under NSPS OOOOb.

Commenters (1583-ODEQ, 2393-OSEE) state that EPA should collect additional empirical data before implementing new regulatory requirements, especially where those requirements will be imposed on existing oil and gas facilities. For example, in the preamble, EPA acknowledges that “certain well sites are smaller than our model facilities, and that as a result the model may overstate emissions reductions, and thus cost-effectiveness, for fugitive emissions programs at such small sites.” This further warrants the justification for an exemption threshold for well sites with low potential emissions. There are too many existing well sites for EPA to properly characterize the fraction that experience unacceptably high fugitive emission rates and to properly assess the cost of control absent additional study. EPA should gather data from a large sample of existing wells with different configurations and fund multiple pilot studies to gather better cost data before embarking on such an ambitious regulatory project.

Commenter (2200-NuEnergy Operating Inc.) states the EPA is proposing the same fugitive emissions monitoring schedule for both new and existing wells. It does not make sense that potential emissions based on throughput, production pressure and product constituents vary between a 20 year old well and a 2 year old well with the exact same equipment. This is unworkable.

Commenter (2211-Lambda Energy Resources) operates about 789 gas and oil wells, 70 central processing facilities, two Natural Gas Processing Plants, and crude oil and natural gas gathering systems. A typical Lambda well produces 6 barrels of oil equivalent per day (BOEPD) and is between 20-50 years old. The IRS classifies as marginal a well producing less than 15 BOEPD. The commenter finds it necessary to voice their concerns over the proposed modifications and additions NSPS OOOOa (new sources), NSPS OOOOb and especially EG OOOOc (existing sources), and the drastic costs and effect these proposed regulations will have on marginal well producers and its employees, vendors, royalty owners, and throughout Michigan and the United States.

Commenter (2244-Private Citizen) supports states’ requirement to provide a written report annually to verify compliance using mandated reporting from all fossil fuel companies.

Commenter (2248-North Dakota Petroleum Council (NDPC)) states the EPA should not make the EG OOOOc the same for existing sources as it does for the new sources covered under NSPS OOOOb. In EPA’s NSR (New Source Review) rule they recognize the challenges of how control technology requirements are applied to major sources (new and existing, and in attainment vs non-attainment). For major source EPA’s regulations on NSR, there are three levels of controls: Reasonably Available Control Technology (RACT) for existing sources, BACT for new sources, and Lowest Achievable Emission Rate (LAER) for new sources in non-attainment. It appears that the EPA is applying LAER type requirements as the BSER for every affected facility and for both NSPS OOOOb and EG OOOOc.

Response II-4-99: As discussed in the December 2022 Supplemental Proposal, the EPA determined that the methods for identifying fugitive emissions (*i.e.*, AVO, OGI, and EPA Method 21), methane emissions reductions, costs, and cost effectiveness for methane emissions

discussed for the fugitive emissions components affected facility at new well sites are also applicable for the fugitive emissions components affected facility at existing well sites. For the final rule, the EPA maintains that the analysis developed for the NSPS OOOOb to determine the BSER is also appropriate for the proposed presumptive standards for the EG OOOOc. The EPA is finalizing this approach for fugitive emissions monitoring, which for existing single wellhead only well sites requires quarterly AVO inspections and for existing small well sites quarterly AVO inspections and closed and sealed requirement for thief hatches. As shown in Table 15 of the December 2022 Supplemental Proposal, the cost of quarterly AVO inspections at existing single wellhead only well sites and small well sites were estimated at \$660 per year per site with a cost-effectiveness of less than \$1,200 per ton of methane reduced, which EPA found to be reasonable.

Comment: Commenter (2410-California Office of the Attorney General et al.) states the undersigned support EPA's adoption of a presumptive standard for existing well sites that follows the same fugitive monitoring and repair program as for new sources. Detecting and repairing leaks does not require installation of controls on existing equipment or retrofits. Rather, as noted by EPA,<sup>218</sup> the technology to address methane leaks is the same at new and existing sites, as are the emission reductions, costs and cost-effectiveness. It is therefore reasonable for EPA to promulgate a presumptive standard for fugitive emissions at well sites that mirrors the new source performance standard.

Response II-4-100: The EPA agrees. The EPA is finalizing presumptive methane standards for existing sources under EG OOOOc that are the same as the methane standards for new sources under NSPS OOOOb.

Comment: Commenter (2179-KIOGA) states the EPA did not provide any regulatory text on EG OOOO, therefore, the ability to provide comments is limited.

Response II-4-101: The commenter is mistaken. The proposed regulatory text for Subpart OOOOc—Emissions Guidelines for Greenhouse Gas Emissions from Existing Crude Oil and Natural Gas Facilities was posted along with the December 2022 Supplemental Proposal on EPA's regulatory website at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce>.<sup>219</sup>

Comment: Commenter (2198-University of Denver College) argue the quarterly monitoring of these new or modified sites under NSPS does not affect sites built before November 15, 2021. As older sites would surely have more issues with leaks. These grandfathered in sites "might try to make use of regular maintenance and repair as an opportunity to gradually rebuild the plant, classifying these as minor improvements rather than major modifications."<sup>220</sup> The addition of covering older sites under the new proposal would have a greater effect on reducing GHGs. Though the cost to do this would be massive, new technology in monitoring GHGs could be used as a cheap and creative solution.

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<sup>218</sup> 86 Fed. Reg. at 63,173.

<sup>219</sup> [https://www.epa.gov/system/files/documents/2022-11/8510\\_OilandGasClimate\\_OOOOc%20RegText\\_Supplemental\\_20221005.pdf](https://www.epa.gov/system/files/documents/2022-11/8510_OilandGasClimate_OOOOc%20RegText_Supplemental_20221005.pdf)

<sup>220</sup> Salzman 2019, 126.

Response II-4-102: In the December 2022 Supplemental Proposal, the EPA proposed fugitive emissions standards for affected facilities for which construction, modification or reconstruction commenced after November 15, 2021 under NSPS OOOOb, as well as Emissions Guidelines for existing facilities under EG OOOOc.<sup>221</sup> The EPA is finalizing standards under NSPS OOOOb for facilities for which construction, modification or reconstruction commenced after December 6, 2022. Designated facilities in the crude oil and natural gas source category that commenced construction, modification or reconstruction on or before December 6, 2022, are subject to the EG OOOOc.

Comment: Commenter (2283-Endeavor Energy Resources) believes EPA should take additional time to craft EGs that reflect the realities of older, existing sources in the oil and gas industry as required by the CAA.

Commenter (2283-Endeavor Energy Resources) states existing source standards should not be simultaneously proposed with new source standards, as EPA has done here, but should instead be informed by experience from implementing finalized NSPS. As EPA has noted in the past, "proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance" allows EPA to "benefit from the comments on the standard of performance in developing the emission guideline."<sup>222</sup> That is equally true here: When EPA proposed Subpart OOOOa, it did not simultaneously propose EGs for methane at that time. This was appropriate, as it would allow for EPA to first benefit from the experience and information gained from observing ways in which Subpart OOOOa was, and was not, effective before applying any standards to the much larger universe of existing sources. Subpart OOOOa has not been in place for very long, due to the legal changes and changes in EPA's proposed requirements over the last few years. As a result, EPA does not yet have sufficient information about the effects or effectiveness of the various requirements it has imposed to limit methane emissions and therefore lacks sufficient information to determine what requirements would be appropriate and effective for existing sources.

Commenter (2283-Endeavor Energy Resources) adds, EPA has not yet received and reviewed comments on its new proposed NSPS, Subpart OOOOb, which introduces a number of additional requirements beyond Subpart OOOOa that have not yet been tested in the field and which are likely to present meaningful implementation challenges. In consideration of these meaningful information gaps, EPA should therefore withdraw the proposed Subpart OOOOc EGs and wait to propose a more appropriate set of regulatory requirements for existing sources with the benefit of additional information and experience. Otherwise, EPA risks finalizing EGs that are arbitrary, capricious, overly burdensome, and unworkable in practice, which would undermine EPA's goal of creating durable methane regulations.

Commenter (2283-Endeavor Energy Resources) notes that when EPA does propose EGs, they should be less stringent than the NSPS requirements in recognition of the very different set of burdens and considerations at play when regulating existing sources. Specifically, the proposed EGs should appropriately accommodate other factors, such as the remaining useful life of existing sources, as required by the CAA.<sup>223</sup> EPA's proposal should reflect the CAA's recognition that there are a fundamentally different set of considerations when regulating

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<sup>221</sup> 87 FR 74702 (December 6, 2022).

<sup>222</sup> See, e.g., 40 Fed. Reg. 53,340, 53,345 (Nov. 17, 1975).

<sup>223</sup> 42 U.S.C. §741 l(d)(l).



existing sources for the first time. Like many operators, the commenter has already planned and budgeted for equipment upgrades at new or modified well sites, but upgrades at the older, existing sites will be more costly to make and will need to be made at far more sites than for new or modified sites. Depending on the specific well site, these capital upgrade costs could fundamentally alter economics associated with operating an existing well, or be entirely infeasible to implement. For example, many existing well sites contain a limited number of controllers, most do not have flares located on site, and the complete retrofit of these sites is likely cost-prohibitive based on well economics. EPA's proposal will require installing and retrofitting a broad range of equipment, including installing electric compressors for air controls, retrofitting all controllers to air systems, installing vapor recovery units on all tanks, installing new low- and high-pressure flares, and installing meters to monitor the volumes sent to flares. In addition, as explained further below, many older well sites do not have access to on-site electricity or a sale line for natural gas because the sites were not built with these considerations in mind. And due to the remote locations of many of these existing sites in the Midland Basin, these kinds of infrastructure upgrades will be extremely costly or entirely outside of an operator's control.

Commenter (2283-Endeavor Energy Resources) does not believe there are a sufficient number of contractors who can meet the needs of all operators in the Midland Basin, and "scaling up" too quickly would pose risks if contractors are forced to rely on new personnel who do not have qualifications, training, and experience to perform the necessary upgrades. This is just one example of why EPA cannot and should not assume that just because requirements have proven to be feasible for the much smaller pool of new or modified sources that operators are also able to implement these requirements more broadly for their existing sources. The commenter believes EPA should instead take the time to fundamentally revisit its proposed EGs after coordinating with the states, who have decades of experience regulating these sites, and operators, who likewise understand the practical realities of implementing these proposals. The commenter encourages EPA staff to visit a variety of well sites in our basin and others to better understand the nature of these facilities and the geography where the commenter is operating. By spending the necessary time up front to understand the industry, EPA can craft durable and workable requirements that will better serve the environment and the public in the long run and avoid issuing a rule that cannot survive legal challenges.

Response II-4-103: EPA disagrees that it is inappropriate to issue New Source Performance Standards and Emissions Guidelines simultaneously for a sector. Draft regulatory text and analyses supporting the proposed text were presented in the December 2022 Supplemental Proposal after taking into account comments on the November 2021 Proposal, and comments on both have been considered in developing the final rule. Differences in costs analyses between new and existing sources are detailed in the 2021 and 2022 TSDs. With regard to a lack of contractors, the commenter does not provide any data supporting their statement.

#### ***4.3.2 Component Counts***

Comment: Commenters (2205-Kriebel Well Services, Inc., 2238-SOOGA, 2294-Ohio Oil and Gas Association, 2446-IPAA) encourage the EPA to not use component counts to define its emissions guidelines. The commenters ask the EPA to align the proposal with states' mindset and use production rates or emissions estimates to define their programs. The use of elaborate component counts is absent in state regulatory programs. This is a major reason why the

commenters have repeatedly recommended using production rates – with the framework of the federal tax code as the calculation method – to define regulatory requirements. EPA's own efforts to try to develop a component count regulatory basis shows that the calculation process is imprecise.

Commenter (2446-IPAA) adds, despite EPA's dismissal of production rates as not being a precise link to emissions, no other approach has shown itself to be appreciably better. In reality, when dealing with a million existing sources that span a wide range of emissions profiles and where the emissions data on those operations are based on a small fraction of the operations, there will never be a structure that provide certainty. In the next phase of this regulatory process – the development of state plans – EPA is setting the stage for unnecessary confrontations with states over the drafting of regulations and the determinations of equivalency. EPA tries to minimize state flexibility by announcing that its analysis is so persistent that states will not be able to demonstrate alternative choices. But, each state has its own regulatory framework and EPA's threatening approach will not easily bend their will. The end result could be regulatory chaos; EPA could end up generating federal plans that it has neither the staff nor the skills to implement. Producers will be faced with two simultaneous regulatory programs which is a patently unfair situation and for small businesses likely crippling. EPA needs to address these predictable consequences now.

Response II-4-104: As discussed in the December 2022 Supplemental Proposal, the EPA did not find that production rates correlate to the amount of fugitive emissions and therefore would not be appropriate to use as a basis for establishing different fugitive emissions monitoring requirements among well sites, including existing well sites. However, the EPA did find that data supports distinguishing among well sites based on equipment and component counts. This approach is applicable to both existing and new well sites.

As discussed in the December 2022 Supplemental Proposal, the EPA found no reason to develop separate requirements for existing well sites, as the monitoring techniques, costs, reductions, and cost-effectiveness were found to be the same for new and existing sites. The EPA is finalizing this approach in the final rule, which includes a less onerous fugitive emissions monitoring structure for single wellhead only well sites and small well sites using AVO inspections only. This final requirements for single wellhead only well sites and small well sites take into consideration the impact of the fugitive emissions monitoring requirements on small businesses, including requirements that affect small operators at existing sites). Inspections using AVO do not require specialized equipment or operator training and is a less costly and burdensome requirement. More stringent is being finalized for multi-wellhead only well sites and large well sites with major production and processing equipment that using OGI and AVO to detect fugitive emissions.

#### ***4.3.3 Definitions and Text Changes***

Comment: Commenter (2177-Ute Indian Tribe) suggests the following change to OOOOc:

"~~Discussion of s~~System calibration requirements, including but not limited to, the calibration procedures and calibration schedule for the detection systems and meteorology systems."

Response II-4-105: The EPA disagrees that this change is necessary. The final rule maintains the language as proposed.

Comment: Commenter (2214-BCAO) requests clarification of 40 CFR 60.5420c(b)(8)(i)(A) as to whether there is a hierarchy on which type of site should be reported if there is more than one type of site at a facility, or if the facility is to report them all.

Response II-4-106: There is no hierarchy as to which site is to be reported. Each fugitive emissions components designated facility at a well site, centralized production facility, or a compressor station should be reported. Each fugitive emissions components designated facility can occur at only one type of site; the same designated facility would not be located at both a well site and a compressor station, for example. While both sites may have fugitive emissions components, and the fugitive emissions components at both sites may be designated facilities, they would be separate designated facilities. Both designated facilities could be included in the same annual report, but they would be reported as separate designated facilities within the report, with the type of site indicated for each of the designated facilities.

#### **4.3.4 Small Business/Cost Concerns**

Comment: Commenters (2211-Lambda Energy Resources, 2218-TCEQ, 2238-SOOGA, 2247-Ohio EPA, 2353-CrownQuest Operating, LLC.) express concerns over the costs that could be incurred by sources subject to EG OOOOc, particularly for smaller operators.

Commenter (2211-Lambda Energy Resources) states most significantly, the proposal to base emissions estimates for well equipment and monitoring on the types and counts of equipment at a site rather than throughput, will require the same expensive retrofitting and monitoring for a typical Lambda well producing 6 BOEPD as is required for a well producing 100 barrels BOED and 20 times the revenue and emissions. Lambda estimates that required retrofitting and increased monitoring and recordkeeping for existing marginal wells required by the proposed regulations would impose new, additional costs of between \$5 and \$10 thousand dollars per well per year, and between \$4 and \$8 million total annually, for Lambda as a company.

Commenter (2218-TCEQ) states the proposed rule also presents increased regulatory overlaps and inconsistencies between currently available construction authorization mechanisms and previous NSPS for this source category as related to monitoring requirements. Texas minor source air authorizations (including Permits by Rule (PBR), Standard Permits, and Case-by-case Permits) have established fugitive monitoring programs that differ based on the facility types and quantity of emissions at a site.

The commenter (2218-TCEQ) notes Texas has many smaller oil and gas sites that may not be subject to registration requirements as part of an authorization under the PBR specified above. Also, many of these sites are already subject to additional monitoring under the previous NSPS (Subparts OOOO or OOOOa). These overlapping requirements make it difficult for the commenters and regulated entities to keep track of the applicable regulations and evaluate compliance. The commenter recommends the proposed rule include an alternative monitoring schedule for sites that demonstrate low leakage rates.

Commenter (2218-TCEQ) states as of December 2022, there are over 287,000 active wells (including oil, gas, and service wells) monitored by the Texas RRC. Many of these are unmanned or minimally staffed well sites in remote locations, presenting potential logistical and compliance issues. Owners or operators of affected sites in remote locations may have difficulty recruiting and retaining sufficient staff to support a regular monitoring program. It will also be burdensome for the commenter (2218-TCEQ) to conduct additional on-site compliance and enforcement activities.

Commenter (2218-TCEQ) states the sheer number and distribution of wells in Texas makes quarterly AVO monitoring a burden for operators and results in only a slight reduction in emissions. Additionally, this may place a significant burden on smaller operators. There are numerous small operators for which the costs of complying with the proposed requirements will be high compared to the income from their operations. In Texas alone, over 4,100 operators own and operate 10 or less oil leases and gas wells. Therefore, AVO monitoring of wellhead only sites would likely provide minimal additional reductions compared to cost.

Commenters (2200-NuEnergy Operating Inc., 2211-Lambda Energy Resources, 2238-SOOGA, 2294-Ohio Oil and Gas Association, 2403-PAO, 2446-IPAA) state EPA's BSER for fugitive emissions fails to properly account for the impact of declining production reducing the potential magnitude of emissions from production facilities. This results in inflexible and, thus, unreasonable monitoring requirements under the Supplemental Proposal. The commenter requests that EPA provide for flexibility in the fugitive monitoring requirements such that as production declines and a well site moves from the large well facility category to the small well facility category, the requirements applicable to the facility should change accordingly to the appropriate facility status, *i.e.*, single well site, multiple well site, small well site or intermediate well site.

Commenter (2200-NuEnergy Operating Inc.) states the EPA is not addressing production decline, stripper well operation, marginal well production, or the IRS's definition of marginal wells when considering the cost benefit analysis.

Commenter (2211-Lambda Energy Resources) adds that the exemption in previous proposals for existing marginal wells has been removed from the December 6 proposed regulations, and there is no "off ramp" for wells once they reach marginal production status.

Commenter (2403-PAO) requests EPA incorporate into the rule a regulatory framework that reflects the nature of oil and natural gas production *i.e.*, well production/emissions decline over time.

Commenter (2446-IPAA) states whatever has been done to develop NSPS fugitive emissions regulations has always been a precursor to its impact on existing source facilities that were never directly addressed in the NSPS regulations. Even the CTG only adopted the basic fugitive emissions regulatory framework for its model regulation. On the other hand, all of the information that EPA has used in its regulatory development – both emissions estimates and technology evaluations – comes from existing sources.

Commenter (2238-SOOGA) expresses that one of the critical flaws of the subpart OOOO regulations, including subpart OOOOb and OOOOc, is the failure to properly account for the

declining production of oil and natural gas from a well over time. The corresponding decline in emissions in connection with various operational changes at the well site is also associated with the decline in production. While initial production at a well may be significant, it will deplete as the well ages and eventually become a low production well. The failure to properly account for this change skews the fundamental basis of the entire subpart OOOO program, *i.e.*, the cost-effectiveness analysis for establishing the BSER for each source that is subject to the program. The magnitude of this fundamental flaw is most significant in the resulting EG OOOOc for existing sources, which have a disproportionate and detrimental impact on low production wells and small businesses.

Commenter (2238-SOOGA) adds the corresponding decline in emissions in connection with various operational changes at the well site is also associated with the decline in production. While initial production at a well may be significant, it will deplete as the well ages and eventually become a low production well. The failure to properly account for this change skews the fundamental basis of the entire Subpart OOOO program – *i.e.* the cost-effectiveness analysis for establishing the BSER for each source that is subject to the program. The magnitude of this fundamental flaw is most significant in the resulting EG OOOOc for existing sources, which have a disproportionate and detrimental impact on low production wells and small businesses.

Commenter (2238-SOOGA) believes the fundamental flaw in EPA's Subpart OOOO regulations has resulted in a misguided BSER determination for existing sources that effectively regulates existing sources the same as new and modified sources. The Supplemental Proposal is based on the assumption that existing facilities can be retrofitted at a reasonable cost to meet the same emissions standards applicable to new and modified sources. The EPA made a gross miscalculation in this regard. Many of the commenter's members lack the financial capital to retrofit existing sources with the equipment necessary to comply with the emissions standards under the Supplemental Proposal. The burden becomes heavier to have technical staff and legal advisors to assist with understanding and complying with the myriad of requirements that they will be subject to, including AVO inspections, conducting root cause analyses, recordkeeping, and reporting, all with significant costs associated with conducting those activities. Even assuming operators *could* pay for costs to retrofit, as a well approaches the end of its useful life, there is a point at which it is no longer economic to make the necessary retrofits. The EPA assumes compliance to be feasible and cost-effective, however, the reality is that the stringent emissions standards under the Supplemental Proposal are impossible, impractical, and inconsequential to methane reduction in most cases, and especially for low volume production wells.

Commenter (2247-Ohio EPA) states in many of those cases, wells have transitioned from a production well that sells the gas/oil produced to a well that simply provides gas/oil to a single-family home. In other cases, small businesses own multiple wells in an area.

Commenter (2247-Ohio EPA) continues, these single families or small businesses will struggle to do the AVO program inspections and reporting. The commenter's experience is that these small operators will not be able to fully understand what they need to do under these rules. Rather than asking these small operators to figure out what they need to do under the EGs, there needs to be either (1) some de minimis cut-off for small wells so they do not have this burden, or (2) a different approach where the small business assistance program or a consultant (with federal funding) does this work for them. The goal of making sure these small wells are not

leaking significant quantities of gas may be a good one, but the traditional approach of writing a rule and then expecting small operators to figure out what needs to be done to comply, in their experience, does not work well. Rules for these small

Commenter (2326-AXPC) asks the EPA to appropriately quantify and assess the feasibility, costs, and benefits of implementing new requirements for existing facilities.

Commenter (2353-CrownQuest Operating, LLC.) states EPA should have considered the OOOOc costs and impacts of the RIA on small businesses. The EPA has already stated that it will not accept traditional state plans, such as Texas' permit-by-rule methods. They will require all states to meet at least their minimum requirements. The EPA's proposed BSERs are restrictive, limit state implementation, and significantly affect a much larger universe of small businesses because OOOOc is basically identical to OOOOb. For example, Texas' (using the Railroad Commission's 2021 production data) top 22 operating entities account for 55% of Texas' production, while the smallest 2,477 entities account for less than 1%. These proposed rules will primarily impact those operators. The total production from those entities was 31,055 BOPD and 99,710 MCFPD (36 BCF/year) from 29,520 leases equaling 3 MCFPD per lease. The proposed regulations are uneconomic based on capital, operating increases, and regulatory burden. The proposed BSER's recordkeeping and reporting will make operating these leases uneconomic.

Response II-4-107: As discussed in the December 2022 Supplemental Proposal, the EPA did not find that production rates correlate to the amount of fugitive emissions and therefore would not be appropriate to use as a basis for establishing different fugitive emissions monitoring requirements among well sites. However, the EPA did find that data supports distinguishing among well sites based on equipment and component counts. The EPA is finalizing this approach in the final rule, which includes less burdensome requirements for smaller sites, and a more stringent monitoring regime for well sites with leak-prone equipment.

Contrary to a commenter's assertion that requiring monitoring based on the type and counts of equipment at a site rather than throughput will require the same expensive retrofitting and monitoring for a lower-producing well and a higher-producing well, the EPA disagrees. First, the methods for identifying well site fugitive emissions (*i.e.*, AVO, OGI, and EPA Method 21), methane emissions reductions, costs, and cost-effectiveness for methane emissions, are the same for fugitive emissions components affected facilities at new well sites and at existing well sites. Second, the fugitive emissions monitoring requirements do not require the installation of controls on existing equipment or the retrofit of equipment.

During the development of the rule, the EPA assessed all aspects associated with the feasibility, costs, and benefits of requiring fugitive emissions monitoring for existing facilities. The annual costs and cost-effectiveness for the fugitive emissions monitoring type and frequency chosen for existing well sites and centralized production facilities were provided in Tables 15-19 of the December 2022 Supplemental Proposal preamble.<sup>224</sup> In the December 2022 Supplemental Proposal, the EPA also presented the costs and cost-effectiveness of the other monitoring frequencies that were evaluated, but that were determined to have costs that were not reasonable.

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<sup>224</sup> 87 FR 74738-74739 (December 6, 2022).

The EPA also considered the impact of the fugitive emissions monitoring requirements on all small businesses (*i.e.*, requirements that affect small operators at new and existing sites). This was a factor in determining that for single wellhead only well sites and small well sites, quarterly AVO surveys were appropriate. Inspections using AVO do not require specialized equipment or operator training but does allow the identification of large leaks. In addition, AVO monitoring can easily be built into regular maintenance activities that are designed to keep the equipment at the site in good working order. The EPA is also including final requirements which allow AVO and soap bubble tests as an option for finding fugitive emissions, particularly because they are low cost and easy to implement alternatives for detecting leaks. The EPA believes this will particularly benefit small entities because AVO surveys at these types of well sites are effective at identifying the types of large emissions from sources located at these well sites at a much lower cost than OGI surveys.

#### **4.4 EG OOOOc Fugitive Emissions from Compressor Stations**

Comment: Commenter (2410-California Office of the Attorney General et al.) supports EPA's revised approach of monthly AVO monitoring and quarterly OGI monitoring of fugitive emissions at new and existing compressor stations. California requires quarterly Method 21 inspection of compressor stations with the option of OGI monitoring, as long as a Method 21 inspection is performed in the event OGI monitoring detects a leak.<sup>225</sup> New York regulations require bimonthly monitoring at compressor stations using EPA Method 21, OGI, or an approved alternative that is at least as effective.<sup>226</sup> Colorado's regulations require quarterly inspections of fugitive VOC emissions greater than or equal to 50 tpy, bi-monthly if greater than or equal to 50 tpy and located within a disproportionately impacted community or within 1,000 feet of an occupied area, or monthly if greater than or equal to 50 tpy.<sup>227</sup> The States and Cities further support EPA's adoption of a presumptive standard for compressor stations in the OOOOc emission guidelines that follows the same fugitive monitoring and repair program as for new sources.<sup>228</sup> As EPA recognizes,<sup>229</sup> the BSER analysis is the same for both new and existing sources.

Response II-4-108: The comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

#### **4.5 Well Sites and Compressor Stations on Alaska North Slope**

Comment: Commenter (2317-Alaska Oil and Gas Association (AOGA)) believes EPA should revise the proposed fugitive emissions LDAR requirements to address the unique conditions that face Alaska producers.

Commenter (2317-AOGA) states in the November 2021 proposal, EPA proposed several amendments to LDAR monitoring frequency requirements for Alaska North Slope (ANS) well

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<sup>225</sup> Cal. Code Regs., tit.17, §§ 95668-95669.

<sup>226</sup> 6 NYCRR 203-7.2(c).

<sup>227</sup> 5. Colo. Code Regs. 1001-9:D.II.E.3.a & Tbl. 3.

<sup>228</sup> 86 Fed. Reg. at 63,174.

<sup>229</sup> *Id.* at 63,196.

sites and compressor stations in recognition of the cold temperatures that prevail for longer periods on the ANS than in other parts of the country, and the infeasibility of conducting OGI during half the year.<sup>230</sup> The commenter states in support of these provisions, and requested several additional adjustments to account for the logistic challenges of conducting LDAR monitoring on a large number of facilities during a very short season.<sup>231</sup>

Commenter (2317-AOGA) request that EPA allow up to 14 months between annual surveys, and provided a detailed technical justification for the additional month.<sup>232</sup> The commenter notes that the current proposal retains the 13 month interval maximum interval between surveys,<sup>233</sup> and the preamble does not mention or address the commenter's request.<sup>234</sup>

Response II-4-109: The EPA acknowledges the comments provided regarding the special challenges facilities located on the Alaska North Slope face. The EPA is already including different provisions for fugitive emissions components affected facility located on the Alaska North Slope. These provisions take into consideration the unique challenges of well sites and compressor stations on the Alaska North Slope by providing an annual fugitive emissions monitoring schedule, which the EPA believes accommodates for the extreme cold temperature. In the final rule, the EPA is retaining the annual monitoring requirement for well sites and compressor stations located on the Alaska North Slope. Consecutive annual monitoring surveys would be required at least 9 months apart and no more than 13 months apart.

Comment: Commenter (2317-AOGA) requests a limited extension of the two year deadline for repairs that are technically infeasible or unsafe for facilities located on the Alaska North Slope.<sup>235</sup> The commenter points out that the emissions impacts of shutting down a well site to fix a leaky flange can vastly exceed the emissions from the leak itself, especially when a line needs to be evacuated (vented) to allow for safe work. The commenter urges EPA to apply the schedule imposed in other LDAR rules by omitting the two year hard deadline, but retaining the requirement that delayed repairs must be completed during the next scheduled shutdown.<sup>236</sup> The commenter recognizes that EPA may not want to have indefinite periods of time where a leak is detected but not repaired. If EPA believes that the rule must include a hard deadline, the commenter suggests that the EPA specify the deadline for completion of repairs as the earlier of three years from detection or during the next scheduled shutdown. The longest turnaround interval reported by the commenter's members is three years. The additional scheduling flexibility will avoid the scenario in which the emissions from a forced shutdown to repair the leak dwarfs the emissions impact from the leak itself.

Response II-4-110: The EPA is finalizing provisions to allow for delay of repair for parts unavailability, in no case allowing for delay beyond 2 years. The EPA believes this time frame is sufficient.

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<sup>230</sup> 86 Fed. Reg. at 63163 (Nov. 15, 2021).

<sup>231</sup> 2022 AOGA Comments (January 31, 2022) at 2-5, Docket OAR-2021-0317-0916, Attachment B to these comments.

<sup>232</sup> 2022 AOGA Comments at 3-5, Attachment B to these comments.

<sup>233</sup> Proposed § 60.5397c(g)(1)(v).

<sup>234</sup> 87 Fed. Reg. at 74740.

<sup>235</sup> 2022 AOGA Comments at 5-6.

<sup>236</sup> Id. at 6.



Comment: Commenter (2440-Nevada Nanotech Systems, Inc.) states difficult environmental conditions such as the North Slope are an ideal application for advanced continuous monitoring systems. The most advanced of such systems contain Built In Self Test features that ensure reliable operation even in harsh environments for up to 15 years. They operate accurately at temperatures down to -40C and have been tested night and day in all environmental conditions (rain, snow, dust etc). The commenter encourages the EPA to also allow continuous monitoring technology solutions as a BSER for the North Slope to provide year-round continuous monitoring and maximum reduction of methane emissions.

Response II-4-111: The EPA disagrees that continuous monitoring technology is the BSER because we do not have sufficient information to include this new but rapidly advancing technology in the BSER analysis; however, the EPA supports the use of continuous monitoring systems to detect fugitive emissions. The EPA is providing a pathway for owners and operators to utilize continuous monitoring technologies at well sites and compressor stations as part of the advanced methane detection technology provisions of the rule. Please see section X.B.2 of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology. These alternative GHG and VOC standards through the use of continuous monitoring system apply to all fugitive emissions components affected facilities, including fugitive emissions components affected facility located on the Alaska North Slope.

Comment: Commenter (2248-North Dakota Petroleum Council (NDPC)) adds, like Alaska, North Dakota's weather poses many safety and logistical challenges that can limit inspector access to oil and natural gas locations for days or weeks. Ice, snow, rain, fog, frigid temperatures, high winds, and flooding are common occurrences in North Dakota. North Dakota is the coldest state in the Continental U.S. during the winter and fall,<sup>237</sup> and in 2022 saw temperatures below -27 °F with the wind chill as low as -60 °F. The commenter requests that similar variances be given to wells in areas that lack the adequate infrastructure or experience the same limitations on access.

Commenter (2248-NDPC) adds unlike some oil and natural gas basins where the facilities are densely spaced, facilities in the Willison Basin are spread out. LDAR inspectors have a lot of windshield time between facilities, and this can be significantly impacted by bad driving conditions. Increasing the frequency of LDAR inspections reduces the window of opportunity a company must reschedule inspections delayed by bad weather conditions. Also, some activities at well sites may increase the safety risk to the LDAR Inspector. These activities include but are not limited to well completion, maintenance, construction activities, or times when a well site is shut-in from production. The commenter does not wish to expose the inspector to unnecessary safety risks during these times.

Commenter (2248-NDPC) notes there may be periods of time when a facility LDAR inspection must be delayed for the reasons stated above. The commenter would like to see some additional acceptable reasons for delaying inspections added, including adverse weather conditions, unsafe site conditions, and facility production shut-in.

Commenter (3604-Riverside Operating Company (ROC)) adds ROC owns and operates over 5,000 natural gas wells in northern Michigan and there are concerns with respect to the proposed

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<sup>237</sup> [www.worldatlas.com](http://www.worldatlas.com).

regulations, namely, economic impact on marginal wells and the overall cost burden, as well as increased operational challenges in northern Michigan; to include lack of sunlight in the winter months preventing solar power from being a viable option along with hundreds of well sites located in remote rural areas.

Response II-4-112: The EPA has included in the final rule, as proposed, a provision in §60.5397b(g)(4) that accommodates for special weather conditions below 0°Fahrenheit where quarterly OGI monitoring is required. Specifically, the quarterly OGI monitoring requirements in §60.5397b(g)(1)(iv) and (v) are waived for any fugitive emissions components affected facility located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The EPA believes this satisfies the commenter's concern.

## Chapter 5. Advanced Methane Detection Technologies

### 5.1 General Comments and Support

Comment: Several commenters (2181-Ute Indian Tribe of the Uintah and Ouray Reservation, 2198-Private Citizen, 2212-Union of Concerned Scientists (UCS), 2235-SLB, 2237-State of North Dakota Industrial Commission and North Dakota Department of Environmental Quality, 2256-Mille Lacs Band of Ojibwe, 2296-New Mexico Environment Department (NMED), 2310-Montana Department of Environmental Quality (MTDEQ), 2333-LongPath Technologies, Inc. (LongPath), 2432-Action Group for Incentivizing Methane Emissions Detection by Advanced Technologies (AGIMEDAT), 2433-Environmental Defense Fund (EDF) *et al.*) express support for EPA's consideration of alternative methane detection technologies under the proposed requirements for fugitive emissions.

Commenter (2181-Ute Indian Tribe of the Uintah and Ouray Reservation) states staff of the Ute Tribe's Air Quality Program have had the opportunity to accompany EPA inspectors during EPA inspections, accompany oil and gas operators conducting LDAR inspections, and have also conducted our own inspections using an OGI camera. In all instances, it has been observed that a majority of the facilities have some form of fugitive emissions.

However, given the sheer number of facilities that would be subject to the final rule, the EPA should consider working with the Ute Indian Tribe to develop a comprehensive LDAR program which may include delegation of inspection and enforcement activities to the Tribe. Additionally, the EPA should consider allowing technologies that provide quantifiable, verifiable, consistent monitoring, and compliance data at a scale that can accommodate large remote regional areas consisting of hundreds or even thousands of facilities. As the EPA heard in the public hearings on this Proposed Rule, there is a great benefit to all operators and regulators to allow the use of new and widely accepted technologies to prevent leaks and fugitive emissions.

Commenter (2198-Private Citizen) notes EPA assumes emissions impacts of these new proposals will begin in 2026. From now until the impacts of these new processes have merit, it would be unfortunate to use antiquated methane measuring techniques. The potential for EPA to work with new satellite technology could be a huge leap forward in monitoring all greenhouse gases.

Commenter (2212-UCS) notes that technologies enabling methane leak detection and monitoring have been rapidly advancing, greatly expanding awareness and understanding of the scale and scope of the methane pollution problem<sup>1</sup> as well as beginning to facilitate rapid and targeted repairs. These technological advances have made clear the limitations of earlier monitoring approaches and the importance of EPA developing pathways for regularly incorporating new methodologies and technologies as they become available.

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<sup>1</sup> Results from one recent three-year aerial survey focused on the Permian Basin identified nearly 1,100 super emitters over the course of the study, including 30 sites that emitted methane for multiple years (see, *e.g.*, Carbon Mapper and Environmental Defense Fund reporting here: <https://www.edf.org/media/dozens-super-emitting-oil-and-gas-facilities-leaked-methane-pollution-permian-basin-years-end>).

Commenters (2235-SLB, 2432-AGIMEDAT, 2433-EDF *et al.*) commend the EPA for including provisions in the Proposed Rule for the use of advanced technologies as alternatives to optical gas imaging (OGI) surveys.

Commenter (2256-Mille Lacs Band of Ojibwe) believes that by encouraging the deployment of innovative and advanced monitoring technologies all along the natural gas and crude oil pipelines and their systems would ensure accountability and reliability in identifying methane and volatile organic compound (VOC) leaks early, so that they may be rectified as quickly as possible.

Commenter (2296-NMED) strongly urges the EPA to authorize the use of next generation monitoring tools to determine compliance with the requirements of the proposed rule. This is an equally important concept for industry to utilize to monitor emissions as it is for states to use to assure compliance with applicable rules. There are several innovative compliance approaches that can be used to effectively and efficiently monitor sources for compliance, while balancing the already strained resources of state agencies. Given the magnitude of affected sources that will be brought under the rule, EPA should consider allowing technologies that provide quantifiable, verifiable, and consistent monitoring and compliance data at a scale that can accommodate large remote regional areas consisting of hundreds or even thousands of facilities. The commenter supports these innovative approaches and has provided a mechanism for their use in our state rule. Alternative monitoring strategies must be effective, enforceable, and equivalent and are a critical option for ensuring that emission leaks are identified and repaired as required.

Commenter (2310-MTDEQ) supports the utilization of new technologies and techniques and encourages further development of the proposed rule in this area if it is to be implemented.

Commenter (2333-LongPath) states that to ensure that the rule is technology neutral, and that maximum emissions reductions are achieved, it urges EPA not to include greater response requirements or more stringent emissions thresholds for some technologies than others. The commenter is very supportive of the progress made between the November 2021 draft proposal and the supplemental proposal for continuous monitoring. The commenter strongly supports the use of methane emission rates (rather than concentrations) and the use of these technologies for emissions monitoring of covers and closed vent systems (CVS). The commenter also believes EPA is correct in identifying “valid” (that is, 3rd party blind validated for accuracy) emission rate measurements as a prerequisite for use of technologies under these provisions.

Commenter (2432-AGIMEDAT) supports EPA’s aim to create a technology-agnostic, performance-based alternative test method framework that provides pathways for utilizing existing and future advanced technologies and performance improvements. These provisions have the potential to improve the efficacy and efficiency of emissions monitoring because advances technology can provide more comprehensive spatial and/or temporal coverage than that required for standard OGI surveys, which can lead to a greater volume of detected emissions.

Based on cost information that is available, commenter (2433-EDF *et al.*) also understands that these technologies are typically much cheaper to deploy than OGI (half the cost or less).<sup>2</sup>

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<sup>2</sup> 2022 Joint Environmental Comments, *supra* note 1, at 116–19.

Allowing advanced technologies as an alternative to OGI through a matrix is a reasonable decision that fits well with EPA's section 111 authority and the Clean Air Act (CAA) more broadly. The CAA is a technology-forcing statute,<sup>3</sup> and section 111 "looks toward what may fairly be projected for the regulatory future, rather than the state of the art at present."<sup>4</sup> EPA can therefore design frameworks that accommodate reasonably anticipated improvements in detection capabilities, rather than the limitations of currently in-use technologies, particularly where (as here) the anticipated advancements are optional rather than mandatory. Most importantly, in providing any alternative compliance option, EPA must ensure that emission reductions equal to or greater than the best system of emission reduction (BSER) will occur.<sup>5</sup>

Commenter (2433-EDF *et al.*) points out that the D.C. Circuit has indicated that "EPA may provide sources with multiple work practice compliance options if EPA demonstrates that at least one of these options is cost effective and 'expressly provides for the alternative in the standard.'"<sup>6</sup> The commenter indicates that the OGI based BSER is cost-effective and EPA has proposed an alternative work practice of "periodic or continuous screening with advanced measurement technology instead of OGI and audio, visual, and olfactory (AVO) monitoring according to minimum detection sensitivity of technology."<sup>7</sup> This voluntary (but once chosen, enforceable) alternative is supported by precedent,<sup>8</sup> and EPA has appropriately followed the statutory requirements by ensuring equivalent emission reductions will occur.

Response II-5-1: EPA acknowledges the commenters' support for alternative methane detection technologies for fugitive emissions.

Comment: Commenter (1649-The Sisters of St. Francis of Philadelphia (SSFP)) asks EPA to require innovative technology. The commenter states it is not enough to "encourage" innovative technology; EPA must "require" it. EPA must also recognize that States are lagging in using updated technology and it is time to implement technical and procedural fixes to record methane leakage. The commenter suggests that quality and expert education in these innovative technologies be required of oil and gas sector.

Response II-5-2: EPA acknowledges the commenters support for the use of alternative technologies. EPA disagrees that advanced methane detection technology is the BSER because we do not have sufficient information to include this new but rapidly advancing technology in the BSER analysis. Additionally, these technologies and associated methods for their applications have not been adequately demonstrated to achieve the same emission reduction as OGI, which is the required BSER in this rulemaking. However, EPA supports the use of these

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<sup>3</sup> Union Elec. Co. v. EPA, 427 U.S. 246, 257 (1976).

<sup>4</sup> Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973).

<sup>5</sup> See, e.g., U.S. Env't Prot. Agency, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. Background Technical Support Document for the Final New Source Performance Standards. 40 CFR Part 60, Subpart OOOOa, at 56–57 (May 2016), <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7631> (comparing Method 21 effectiveness at 500 and 10,000 ppm and finalizing 500 ppm as alternative in order to achieve reductions equal to or greater than OGI BSER).

<sup>6</sup> 73 Fed. Reg. 78199, 78200 (Dec. 22, 2008) (citing Arteva Specialties S.R.R.L., d/b/a KoSa v. EPA, 323 F.3d 1088, 1092 (DC Cir. 2003)).

<sup>7</sup> 87 Fed. Reg. at 74708–09.

<sup>8</sup> See, e.g., 73 Fed. Reg. 78200 (Dec. 22, 2008).

systems to detect fugitive emissions. The EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (2226-Thermo Fisher Scientific (Thermo Fisher)) encourages EPA to move forward with finalizing the rule to initiate the program as soon as possible so that the capable measurement and monitoring technologies that are ready today can be deployed. This would also enable technology providers to begin to understand and prepare for equipment needs and behaviors under the program, as well as under the WEC, or 'methane fee' program, that the oil and gas industry must adhere to if they do comply with the NSPS for new and existing sources. At this time, the commenter requires further insights as to how the oil and gas industry will interact with measurement and monitoring technologies so that we can supply the equipment necessary for compliance in a timely manner. The development of future technologies relies largely on the needs and opportunities as outlined in the final version of this EPA program. Due to supply chain challenges and ramp-up timescales, the commenters states that their industry requires ample lead time to develop and manufacture the equipment necessary for these programs. Thus, advance notice and insights to inform proper scaling up is key. With this information, the commenter is certain that it can provide the equipment necessary to achieve the goals of the program.

Response II-5-3: EPA acknowledges the commenter's support for advanced methane detection technologies. EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

### ***5.1.1 Technology-Neutral/Matrix Approach/Flexibility***

Comment: Commenters (1609-Qnergy, Inc., 1649-SSFP, 2039-Citizens to Preserve Ligonier Valley, Inc., 2152-California State Teachers' Retirement System, 2163-EOS at Federated Hermes, 2164-Nordea Asset Management, 2177-Southern Ute Indian Tribe (Southern Ute), 2184-Physicians for Social Responsibility (PSR), 2185-New York State Comptroller (NYSC), 2190-Miller/Howard Investments, Inc., 2191-Boston Trust Walden Company, 2203-Ceres, Inc. (Ceres), 2206-Legal & General Investment Management America, Inc., 2212-UCS, 2226-Thermo Fisher, 2242-Seventh Generation Interfaith, Inc., 2247-Ohio Environmental Protection Agency (OHEPA), 2251-National Association of Manufacturers (NAM), 2254-Permian Basin Petroleum Association (PBPA), 2256-Mille Lacs Band of Ojibwe, 2287-Interfaith Center on Corporate Responsibility, 2298-Pioneer Natural Resources USA, Inc. (Pioneer), 2299-NEI Investments (NEI), 2309-Planet Labs PBC (Planet), 2310-MTDEQ, 2316-ABB, Inc. (ABB), 2326-American Exploration and Production Council (AXPC), 2350-Cheniere Energy, Inc. (Cheniere), 2355-Constellation Energy Corporation (CEC), 2363-Continuous Emission Monitoring Coalition (CEMC), 2365-Climate Action California, 2388-ExxonMobil, 2424-As You Sow, 2429-Wyoming Outdoor Council, 2433-EDF *et al.*, 2446-Independent Petroleum Association of America (IPAA), 2458-MiQ, 2459-BMO Global Asset Management, 2627-

British Columbia Investment Management Corporation (BCI), 2696-Congressman Scott H. Peters *et al.*) express support for EPA's proposal to include the flexibility to use advanced methane detection technologies to assess leaks in lieu of OGI or EPA Method 21.

Response II-5-4: EPA acknowledges the commenters' support for EPA's allowance of advanced methane detection technologies to assess leaks in lieu of OGI or EPA Method 21.

Comment: Commenters (2203-Ceres, 2298-Pioneer, 2446-IPAA, 2458-MiQ) believe that there is sufficient evidence to show that aerial screening and monitoring technologies on the market today are capable of detecting fugitive emissions from affected sources as well as periodic surveys using OGI or Method 21. Further, aerial technologies have been shown to detect certain types of emissions that OGI has missed, particularly in field deployment comparisons and across larger areas.

Commenter (2251-NAM) suggests that EPA give oil and gas operators the option to choose between multiple alternative detection technologies in their leak detection and repair (LDAR) plan. Operators should be able to tailor their own LDAR plan for their location and unique operational circumstances. Leak detection technologies that work great in the Permian Basin might not be equally great for the Williston or Marcellus Basins. The commenter encourages EPA to fully embrace and use flexibility in detection/abatement techniques since the technologies get better each year.

Commenter (2308-National Stripper Well Association) believes that technology requirements must be applied fairly. In addition, while EPA is making efforts to allow emerging technologies to be used in fugitive emissions programs, these new technologies are evolving constantly. Whether they currently compare to EPA's assessment of its OGI program, the potential for future technologies cost effectively exceeding the current OGI technology capabilities is likely. As a result, EPA's current mix of technologies and frequencies should change to reflect better methodologies. Producers should not be constrained to the use of outdated methods when better ones arise.

Response II-5-5: EPA has provided flexibility in the final rule for owner and operators to choose the appropriate detection platform for their methane detection surveys by finalizing matrices that tie the frequency of inspection to the method's minimum detection threshold. Owners and operators complying with the alternative fugitive emissions standards using advanced methane detection technologies may choose any approved (or multiple approved) methods to conduct periodic screening events or continuous monitoring. EPA recognizes that technology will continue to improve and has structured the rule to allow for continued improvement instead of relying on legacy measurement approaches by not specifying particular advanced methane detection technologies that owners and operators must meet. Instead, the rule relies on the detection capabilities of the technology.

Comment: Commenter (2299-NEI) believes this flexibility will help offset the cost of enhanced monitoring while also incentivizing the development of increasingly sophisticated direct measurement technologies. The measurement techniques and methodologies that have been relied on traditionally are not providing an accurate capture of methane emissions data and this

lack of accurate data creates a real risk of misallocation of capital. Direct measurement technologies have the potential to provide much more decision useful information.

Response II-5-6: EPA disagrees that existing monitoring techniques for fugitive emissions are inaccurate or ineffective. However, EPA recognizes the benefits of advanced methane detection technologies and encourages the use of these technologies. EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenter (2433-EDF *et al.*) strongly supports EPA's proposed alternative periodic screening option for LDAR at well sites, centralized production facilities, and compressor stations that would allow for the use of advanced methane detection technologies. Innovation in methane detection technologies and deployment methods is advancing rapidly and EPA has taken a careful, technology-neutral approach that will enable the use of these technologies for regulatory compliance.

Commenter (2627-BCI) states the EPA should provide flexibility for compliance by allowing advanced technologies to be used should they deliver equal or better methane mitigation. As these wells drive a significant proportion of all wellsite emissions, the commenter views this as a strong approach to ensure that oil and gas companies can deliver more robust carbon reduction commitments.

Response II-5-7: EPA acknowledges the commenter's support for advanced methane detection technologies. EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

Comment: Commenters (2203-Ceres, 2298-Pioneer, 2446-IPAA, 2458-MiQ) commend EPA's efforts to incorporate advanced technologies as a regulatory option, as well as the inclusion of a matrix in this proposal.

Commenter (2446-IPAA) supports the use of a matrix that takes into consideration inspection frequency and minimum detection sensitivity. The commenter appreciates EPA's willingness to adopt a matrix approach, but as proposed will likely be of limited benefit – the concept is solid, but the implementation falters. The commenter notes that emerging technologies to be used in fugitive emissions program are evolving constantly and whether they currently compare to EPA's assessment of its OGI program, the potential for future technologies cost effectively improving upon the current OGI technology capabilities is high. As a result, EPA's current mix of technologies and frequencies should change to reflect better methodologies. Producers should not be constrained to the use of outdated methods when better ones arise.

Commenter (2298-Pioneer) supports EPA's approach of enabling owners and operators to use advanced technologies through a performance matrix based on inspection frequency and



minimum detection sensitivity. The proposed matrix, combined with alternative test methods, can provide operators and technology developers well-defined requirements for use of an alternative technology for compliance. This clarity is essential for technology developers to continue investing in the design of, and for operators to choose to use, advanced technologies for compliance with this rule. The commenter also supports EPA's use of the Fugitive Emissions Abatement Simulation Tool (FEAST) modeling to demonstrate equivalency with the statutory requirement of BSER.

Commenter (2320-American Public Gas Association) states all aspects of the natural gas supply chain value innovation. In issuing a final rule, the commenter recommends EPA not implement mandatory, prescriptive detection requirements, as this action will disincentivize new technologies. The natural gas industry is committed to research and development efforts. Specifically, there is a track record of developing technologies that aid in the mitigation of methane emissions, which align with the goals of this Proposal. Accordingly, EPA should allow flexibility when it comes to the technologies and the techniques used by the industry for leak detection.

Commenter (2226-Thermo Fisher) supports EPA's decision to enable end-users to select from a range of technologies to adequately measure emissions based on unique site specifications.

Response II-5-8: EPA acknowledges the commenter's support for advanced methane detection technologies. EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

EPA has provided flexibility in the final rule for owner and operators to choose the appropriate detection platform for their methane detection surveys by finalizing matrices that tie the frequency of inspection to the method's minimum detection threshold. Owners and operators complying with the alternative fugitive emissions standards using advanced methane detection technologies may choose any approved (or multiple approved) methods to conduct periodic screening events or continuous monitoring. EPA recognizes that technology will continue to improve and has structured the rule to allow for continued improvement instead of relying on legacy measurement approaches by not specifying particular advanced methane detection technologies that owners and operators must meet. Instead, the rule relies on the detection capabilities of the technology.

Comment: Commenter (2405-Bridger Photonics, Inc. (Bridger)) states since the November 2021 proposal, significant research has been made public that bears critical implications for modeling the performance of different emissions monitoring approaches. To ensure that the final rules are based on an accurate representation of existing emissions distributions as observed by recent measurement campaigns, and modeling is based on the emissions reductions that can be achieved by advanced technologies, the EPA must take this research into consideration. For example, Bridger recently submitted a paper for publication that describes an emission rate distribution measured in the Permian Basin with continuous coverage from large emission rates down to rates

below 2 kg/hr (2 kg/hr emission rates were detected with 90% PoD).<sup>9</sup> It is possible to compare the distribution of emissions simulated in FEAST<sup>10</sup> with this extensive empirical emission rate distribution because it overlaps with the large-emitter, tank, and component emissions rate distributions that were bootstrapped during the EPA's FEAST modeling. Preliminary investigations suggest that emissions with rates between 600 and 1 kg/hr were significantly underrepresented in FEAST simulations, meaning that critical reevaluation may be necessary to avoid promulgating final rules that incorrectly represent the efficacy of different detection sensitivity tiers in the alternative emissions monitoring framework. The commenter urges the EPA to compare FEAST simulated leak fields to Bridger's empirical emission rate distribution to correct and validate modeling inputs. This should be done in a publicly transparent process so that stakeholders can help identify pitfalls and have confidence in equivalency determinations.

Response II-5-9: See discussion in section X.B.1 and XI.B.1 of the preamble to the final rule related to the data EPA used for the FEAST modeling.

Comment: Commenter (2696-Congressman Scott H. Peters *et al.*) expresses that this is an opportunity to allow industry to utilize all the technological tools at their disposal to reduce methane emissions as opposed to the Agency choosing a specific slate of technologies or being overly prescriptive. The commenter urges EPA to work together with states to promulgate regulations that comply with the CAA and allow for the broadest variety of methane emissions detection technologies, or combinations of technologies, while driving towards the use of best available technologies to measure actual site-level emissions. Operators are already using innovative, proven technologies such as on-site continuous monitoring, as well as aerial and satellite monitoring. A technology-neutral approach will enable operators to choose the technology and system design best suited and cost-effective for their facility and geographic region. This is particularly important for rural areas that may have an extra burden to access certain facilities in person, particularly during a time when many companies are having a difficult time recruiting a robust workforce.

Response II-5-10: EPA acknowledges the commenter's support. Through the advanced methane detection technology work practices EPA has finalized, we are applying a technology-neutral approach to this application. Owners and operators are free to the technology that best fits their needs from the approved technologies.

Comment: Commenter (2696-Congressman Scott H. Peters *et al.*) states the result could be a matrix of technologies that could be deployed to achieve the specified level of detection and control. Such a matrix will allow operators to choose the most effective system design for their location without the need for a cumbersome site-specific equivalence demonstration or alternative application process. The matrix should recognize that some technologies have a more sensitive detection threshold, thereby making it possible to require less frequent monitoring. Conversely, for technologies that have a less sensitive threshold, the matrix could require

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<sup>9</sup> Kunkel, W. M. et al. Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure by Aerial LiDAR. EarthArXiv (2023).

<sup>10</sup> US EPA. Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). (2022).

relatively more frequent monitoring. In addition, the matrix should make it possible for operators to evaluate and use a combination of technologies. The commenter believes this will promote ongoing best available technology development towards actual direct emissions measurement and achieve the most emission reductions at least cost.

Response II-5-11: EPA acknowledges the commenter's support. EPA is finalizing an advanced methane detection technology work practice that employs a matrix approach to link inspection frequency to minimum detection threshold.

Comment: Commenter (2284-Kairos Aerospace (Kairos)) strongly supports EPA's decisions to both use fugitive emissions program modeling and to incorporate into its modeling the latest peer reviewed science on emission distributions based on remote sensing technology. The area of emission measurement and computer simulation of leak detection programs is a rapidly evolving one. The commenter encourages EPA to consider periodically updating its modeling protocols based on our evolving scientific understanding to ensure EPA continues reflecting the best available information.

Commenter (2299-NEI) urges EPA to work with States and industry to continue to encourage innovation in monitoring, and specifically to develop means for operators to share monitoring resources and data (where relevant) in order to scale efforts and bring down costs for everyone. Commenter (2458-MiQ) recommends that the matrix be updated on an annual basis using applicable new research.

Response II-5-12: EPA acknowledges the commenters' support of EPA's modeling in development for work practices for advanced methane detection technologies. EPA cannot continuously update the standards in NSPS OOOOb and EG OOOOc after finalizing the standards, as this creates regulatory uncertainty for owners and operators; the standards are based on the best available data and assumptions at the time of this rulemaking.

EPA is aware that our underlying assumptions may change as more emissions data are collected after the implementation of this rule. EPA may use this data to evaluate existing assumptions in the equivalency model and whether any changes are warranted to the periodic screening matrix, as part of the required NSPS review cycle.<sup>11</sup>

Comment: Commenter (2316-ABB) asserts that in all cases, EPA should allow owners and operators a choice in selecting commercially available methane detection technologies that are best suited and most effective for their applications. EPA should emphasize to all stakeholders that the most effective technology, for the greatest public benefit, is rarely the least expensive to purchase. Rather, successful reduction of methane emissions will require the purchase and deployment of proven, effective technology and methods that enable rapid, reliable detection and quantification of large, small, and even hidden leaks. EPA should educate all stakeholders about the availability of new methods that save valuable time (and thus operating costs) by minimizing false positives as well as false negatives. As addressed in a subsequent point, legacy technologies, such as OGI, are simply unable to address current methane leak reduction

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<sup>11</sup> Clean Air Act Section 111 requires that at least every 8 years, the EPA review and, if appropriate, revise standards of performance for regulated NSPS sources.

requirements. Choice in commercially available methane leak detection should also be applied to the proposed “Super-Emitter” program.

Response II-5-13: EPA acknowledges the commenter’s concern. The final rule is designed to provide owner or operators with additional options for methane monitoring. EPA is technology agnostic in the final rule. EPA will post all technologies that are approved for use under §60.5398b(d) on EPA’s Emissions Measurement Center webpage. Owners and operators may investigate and choose the technology that best meets their needs from those listed or request and alternative test method for methane detection technology.

Comment: Commenters (2248-North Dakota Petroleum Council (NDPC), 2294-Ohio Oil & Gas Association (OOGA)) disagree with the above commenters and argue the proposed approach for utilizing alternative leak detection technologies is unworkable and lacks support. Commenter (2248-NDPC) does support the use of advanced methane detection technologies and urges EPA to reconsider including prescriptive requirements within the NSPS rules that could preclude the use of technologies. The commenter is urging the EPA to provide flexibility in the NSPS to use technologies that are presently proven to be successful in each basin. A layered or tiered application of multiple technologies will be the most cost-effective with the greatest emissions detection capability.

Commenter (2294-OOGA) appreciates EPA authorizing alternative leak detection technologies under the Supplemental Proposal. However, the approach for implementing such alternative technologies is based on a matrix of requirements that incentivizes operators to not use any alternative technologies. That is, the Supplemental Proposal allows the use of alternative technologies in place of OGI but with increased monitoring frequencies. EPA’s approach lacks justification and may not be cost effective. The commenter also notes that the technology certification process is unworkable (another disincentive) and that the basis for the continuing monitoring thresholds lacks justification.

Response II-5-14: The matrix frequency is based on a determination of equivalency with the existing BSER for the fugitive program and cover and closed vent system requirements. EPA did not evaluate cost of the alternatives, because they are considered alternatives to the BSER.

EPA has provided flexibility in the final rule for owner and operators to choose the appropriate detection platform for their methane detection surveys by finalizing matrices that tie the frequency of inspection to the method’s minimum detection threshold. Owners and operators complying with the alternative fugitive emissions standards using advanced methane detection technologies may choose any approved (or multiple approved) methods to conduct periodic screening events or continuous monitoring. EPA recognizes that technology will continue to improve and has structured the rule to allow for continued improvement instead of relying on legacy measurement approaches by not specifying particular advanced methane detection technologies that owners and operators must meet. Instead, the rule relies on the detection capabilities of the technology.

### ***5.1.2 Incentivize Advanced Technology***

Comment: Commenters (2333-LongPath, 2363-CEMC, 2448-Project Canary) believe EPA should align requirements between OGI and advanced technologies inspections for instances where an advanced technology finds “deviations” from non-fugitive emission components. Thus, to ensure operators are not assuming additional risk for using an advanced technology that can better detect emissions, the final rule should clarify that if operators discover a process failure using an advanced technology—such as a malfunctioning flare or other failed control device—the operator should repair the failure within a specified period of time and not risk a violation. Operators should also be required to report the failure. If the detected process malfunction is corrected within that specified period and was not caused by operator error or negligence, the owners and operator should not be liable for any violation for a failure of the control device. This approach is consistent with EPA’s 2015 petroleum refinery NESHAP, which would find a deviation only if emissions are caused by operator error, operator negligence, or repeat violations. The commenters urge EPA to design the final rule to create an incentive to look for and repair emission sources through a compliance pathway for process malfunctions for advanced technologies.

Response II-5-15: EPA disagrees with commenters that a change in emission standards is necessary to incentivize the adoption of advanced technologies. EPA recognizes that emissions detected by advanced methane detection technologies could result in finding deviations from emission standards.<sup>12</sup> But owners and operators have a legal duty to operate any affected facility in compliance with applicable standards, including emission limits, and affected facilities must be in compliance with the requirements of the rule at all times. Frequent detection of excess emissions by advanced monitoring technologies should not occur if control devices and other emission sources are adequately engineered to continuously meet applicable emission standards. Allowing “grace periods” for repair during which compliance with emission limits is not required would be inconsistent with and weaken the emission limits determined to be the best system of emission reductions because it would no longer require continuous compliance. “Grace periods” would further disincentivize efforts to address the underlying causes of deviations and take corrective measures to ensure continuous compliance with applicable standards. If monitoring with advanced methane detection technology results in the identification of a deviation from an emission standard, corrective actions should be taken as soon as possible to address the failures. Further actions may also be necessary to address the underlying causes of the deviation and avoid future emission detections by the advanced monitoring technologies. For example, where advanced technologies indicate emissions from covers and closed vent system on an affected facility, which are required to achieve a no identifiable emission standard, an engineering evaluation may be warranted to confirm the system is adequately designed to meet the no identifiable emission standard.

Comment: Commenters (2248-(NDPC), 2360-Devon Energy (Devon)), 2363-CEMC, 2448-Project Canary, 2432-AGIMEDAT, 2458-MiQ) ask that EPA establish a compliance pathway that will incentivize deploying advanced technologies.

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<sup>12</sup> See 87 FR 74743-74744 (December 6, 2022).

Commenter (2248-NDPC) feels the advancement of new technologies are critical for any industry; however, the commenter feels EPA's current proposal on advanced methane detection technologies does not incentivize its use, but conversely disadvantages its use.

Commenter (2360-Devon) supports the proposal of a matrix framework that allows for the use of advanced detection technologies as part of a flexible and effective fugitive emissions monitoring and repair program and offers suggestions to avoid potential disincentives. The commenter states methane emission detection technologies are evolving rapidly and are a key component of the commenter's strategy for broader emission reductions. The commenter believes these technologies have the potential to be more effective at finding leaks on a broader scale, allowing for faster detection and mitigation, leading to a greater reduction in methane emissions. The commenter is concerned that there may be inadvertent disincentives that are contrary to the intent of EPA, which is to encourage innovation resulting in meaningful emissions reductions. If these disincentives persist in the final rule, it may encourage operators to simply continue their existing OGI survey programs as the default option and hinder broad development and adoption of advanced detection technologies.

Commenter (2458-MiQ) recommends that EPA provides a clear 'pathway' for methane detection reporting that would include a defined period or periods to address fugitive methane emissions. According to this recommended approach, the operator would not be out of compliance if the detection is addressed before the end of the regulatorily determined period and a report of the methane emissions, including a quantification of the extent of the emissions, was reported to EPA and relevant state authorities. This compliance pathway could be tiered based on the reason and source of the leak and emission type, as well as the monitoring technology in effect. If the emission source is not mitigated by the end of the determined period, the operator would be in violation. Similarly, if an operator repaired the leak within the allowed period, but did not report the emission, the operator would also be in violation.

Commenter (2458-MiQ) provides the example, the type of tiered structure recommended in this comment could consist of the following:

- Tier 1: Leaks from sources that are not required to be monitored and where performance is not regulated by other regulatory requirements.
  - Repair timeline: x days
- Tier 2: Leaks that include both traditional LDAR leaks and that are already subject to regulatory monitoring; and sources that are not required to be monitored but where performance is subject to other regulatory requirements.
  - Repair timeline: < x days
- Tier 3: Emission detected using OGI technology. If advanced methane technology is available and appropriate for the facility in question and has a lower methane detection limit than the OGI technology that was used to detect the leak.
  - Repair timeline: < x-y days (where x and y are whole numbers)

Response II-5-16: EPA developed the matrix framework to provide a pathway for alternative methane detection technology to be applied to the rule without the requirement to go through the alternative means of emission limitation (AMEL) process, which is like the rulemaking process

in that it requires public notice and an opportunity for public comment. The periodic screening matrix framework EPA is finalizing pairs monitoring frequency with the detection sensitivity of the alternative technology and is a “plug and play” approach. Because the matrix was developed using modeling that demonstrated equivalency to the BSER, there is no need for owners and operators to demonstrate equivalency for individual sites, as long as the owner or operator uses the periodic screening matrix and a technology approved by the Administrator. By approving the technology through an Administrator approval process, EPA can approve technologies in a more streamlined fashion. We disagree this approach disincentivizes the use advanced technology, as any approved technology could be used within the periodic screening matrix framework to achieve equivalent emission reductions to the BSER.

The alternative work practice standards using advanced methane detection technologies clearly lay out the actions (and the timeframes for those actions) that owners and operators must take in response to a detection during a periodic screening event or exceedance of an action level.

EPA notes that owners and operators still have the capability to request an AMEL for an alternative work practice standard to the work practice standards that are included in the final rulemaking. Entities requesting an AMEL would be required to provide a demonstration of equivalency as part of the AMEL application.

Comment: Commenter (2360-Devon) argues, as proposed, the matrix framework seems to require an “all or nothing” approach to advanced detection methods. While these detection technologies have been adopted widely within voluntary programs,<sup>13</sup> there may be times where deployment of these technologies is hindered due to certain weather conditions in the field. For instance, the commenter’s northern assets may have seasonal snow cover that would otherwise prevent the deployment of certain technologies. The commenter encourages EPA to incorporate within the final rule a pathway that allows for programs that use a combination of technologies, both traditional and advanced, to achieve equivalent emission reductions. For example, the commenter could craft a monitoring plan that incorporates traditional OGI surveys during the months when advanced detection technologies cannot be deployed.

For the suite of methane detection technologies that can be classified as continuous or near continuous, the commenter (2360-Devon) is concerned that the rule as proposed will present a barrier to their use as an alternative within a compliance program. The commenter encourages EPA to ensure the rule is technology neutral by not holding some technologies to greater response requirements than others. There is an obvious benefit to encourage the use of technologies that can facilitate rapid detection and mitigation of significant emission events, so they should not be inadvertently discouraged by overburdening them with more stringent response requirements simply because they can detect emissions more frequently. The commenter believes continuous and near-continuous technologies could fit within the periodic screening matrix frequency and detection thresholds, with an appropriate work practice.

Response II-5-17: EPA agrees with the commenter. We did not intend for the periodic screening matrix framework to be an all or nothing system. As explained in Section X.B.1 and XI.B.1 of

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<sup>13</sup> <https://www.prnewswire.com/news-releases/devon-energy-to-use-aerial-gas-mapping-lidar-to-track-down-methane-emissions-across-full-portfolio-301477706.html>.

the preamble of the final rule, EPA has revised the final rule to allow multiple technologies to be used so long as the frequency of the monitoring is reflective of the technology with highest detection threshold.

Comment: Commenter (2360-Devon) also encourages EPA to consider how operators should follow up on methane emissions events detected by advanced continuous, near-continuous, and non-continuous detection technologies. In many cases, the cause and mitigation of an identified emission event can be determined remotely using operational information, including Supervisory Control and Data Acquisition (SCADA) data, negating the need for a follow-up OGI inspection in each and every case. In many cases, it can also provide verification that the event is no longer occurring. This has an additive safety and environmental benefit of reducing the number of miles driven and the resulting emissions from travel to and from the site in question. The commenter also encourages EPA to consider whether the proposed follow-up and repair timeframes are appropriate in every circumstance, particularly given the large amount of data obtained during a flyover screening survey. Operators should be given flexibility to prioritize those events with the highest estimated emission rate when using technologies that have the capability of providing a quantification estimate. Lower priority emission events (*i.e.*, those events with a lower estimated emission rate) should be allowed additional time for follow-up so that available operator resources can be utilized to address higher estimated emission rate events first.

Response II-5-18: EPA agrees that SCADA data is a valuable tool in identifying probable causes of emissions. However, EPA considers it important to follow-up a periodic screening event with a confirmed detection with a ground level measurement to determine if emissions are still occurring, even if at low levels, and whether there are other sources contributing to the detection, other than the source determined through SCADA data. EPA also agrees that SCADA or other data can provide owners and operators with information that allows them to prioritize emission events and address events with larger leaks quicker. The final rules provide sufficient time for follow-up inspection of all detections identified with advanced screening technology.

For continuous monitoring technologies, the final rulemaking requires the owner or operator to conduct an investigative analysis following an exceedance of an action level. The final rulemaking does not dictate what actions the owner or operator must take in response to the action level exceedance, allowing the owner or operator to determine what actions are necessary to reduce the mass emission rate below the action level.

Comment: Commenter (2432-AGIMEDAT) believes the rule inadvertently disincentivizes the adoption of advanced technologies by penalizing more effective detection of emissions with a burden of unnecessary full-site OGI follow-up surveys and/or compliance violations. The final rule should encourage, rather than penalize, the efficient and effective detection of emissions. The commenter advocates for critical revisions to the rule that will incentivize the detection, characterization, and mitigation of emissions by ensuring that (a) the follow-up response to emissions detected with advanced technologies is appropriate to the emission and (b) a compliance pathway is provided for operators to correct detected emissions that would otherwise result in an immediate compliance violation. The commenter urges the EPA to implement the following three technology-agnostic, performance-based solutions as revisions to the final rule.



1. Exclude from the follow-up OGI survey requirement those emissions which are conclusively attributable to sources by investigative analysis.
2. Change the follow-up OGI survey requirement to pertain only within the localization uncertainty region of the advanced technology.
3. Incentivize the detection and mitigation of compliance issues detected by advanced technologies.

Commenter (2458-MiQ) states to incentivize the continued adoption and use of advanced screening technologies, the commenter recommends that a) EPA dedicates resources to the testing and approval process for advanced monitoring technologies, per the process outlined in the supplemental proposal; and b) the matrix be updated on an annual basis using applicable new research. OGI efficacy and inspection frequency should also be updated on an annual basis using applicable new research. This research could, for example, include studies of the comparative effectiveness of different monitoring technologies (both new and existing). Similarly, updated guidance concerning AVO methodology and surveys should be conducted on an annual basis.

Response II-5-19: EPA agrees with the commenter that when a technology has sufficient spatial resolution, it may be unnecessary to conduct a full site wide screening. As explained in Section X.B and XI.B, EPA has revised the final rule to include three different classes for spatial resolution; site-level meaning technology that can identify excess emissions from an area containing a well site, centralized tank battery, and/or compressor station; area-level meaning technology that can detect emissions within 2m<sup>2</sup>, and component-level meaning technology that can detect emissions within 0.5m<sup>2</sup>. Each class of technology has a different OGI follow-up requirement to account for the locality of the detected emissions.

Additionally, see response II-5-12, which responds to the issue of updating the advanced methane detection technology work practices periodically.

### ***5.1.3 Industry Advancing Technologies***

Comment: Commenter (2410-California Office of the Attorney General (CA AG) *et al.*) encourages EPA's support for the use of advanced methane detection technologies for identifying fugitive emissions. The State of California has partnered with private companies, federal agencies, and several academic and philanthropic entities to advance the use of remote sensing plume-mapping technology for detecting emissions. The State of California has committed \$100 million towards the purchase of this type of data from satellites, which will be awarded by a competitive request for proposal process. This technology can pinpoint and quantify leaks and other emissions of methane and carbon dioxide. These efforts build upon a successful partnership between the California Air Resources Board, the California Energy Commission, and the NASA Jet Propulsion Laboratory on a statewide study to identify large methane sources across California. That study, called the California Methane Survey, used similar technology envisioned for the satellites but mounted on airplanes to "see" methane emissions. Many commercial satellite companies are in the early stages of developing and deploying satellites equipped with similar methane plume mapping instruments, along with capabilities to observe up to 25 other environmental indicators. California will continue to

explore how best to use this new information to mitigate emissions even further, both in California and globally.

Commenter (2410-CA AG *et al.*) notes however, given that this technology is still emerging and developing, the States and Cities recommend that alternative screening methods (*e.g.*, aerial surveys) should complement, and not yet completely replace, traditional OGI/AIMM inspections. The commenter further suggests that EPA let states have the flexibility to employ alternative screening after individualized review of the appropriateness of the technology, frequencies, follow-up and repair timelines, as is most effective in the region and for the sites for which the alternative screening is deployed.

Response II-5-20: EPA acknowledges the commenter's support for the alternative technology program. EPA notes that due to the lack of approved technologies and associated methods for their applications, OGI remains the BSER in this rulemaking. However, EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology. Owners and operators would not be able to employ advanced methane detection technologies for compliance with NSPS OOOOb or EG OOOOc until EPA has reviewed and approved the technology.

EPA notes that in implementing regulations for which they have been delegated administrative authority, air agencies may have more stringent requirements than the requirements in federal rules. Additionally, states have flexibility through submittal of the state plans developed for EG OOOOc to identify solutions for the oil and gas basins in their jurisdiction.

Comment: Commenter (2350-Cheniere) supports the EPA's inclusion of advanced methane detection technologies in the supplemental proposal. The commenter notes that in 2021, it embarked on a multi-year, multisector quantification, monitoring, reporting, and verification ("QMRV") program with a number of our key suppliers and a host of leading technology vendors. The commenter initiated the program to assess the capabilities of novel emissions measurement technologies and improve understanding of measurement-informed greenhouse gas emissions specific to the commenter's supply chain. The QMRV program is designed, conducted, and analyzed by scientists at the Payne Institute for Public Policy at the Colorado School of Mines, and University of Texas at Austin, and Colorado State University. In 2022, the

commenter initiated the QMRV program with midstream infrastructure partners and at our pipeline and liquefaction facilities. Results from this work have been published<sup>14</sup> or submitted to peer-reviewed journals.<sup>15, 16</sup>

Commenter (2350-Cheniere) finds the application and efficacy of these emissions measurement technologies vary depending on multiple factors and the sector of the natural gas supply chain. For facilities in the production sector of the supply chain, the commenter concluded that multi-scale measurements are important and necessary to detect and develop measurement-informed inventories, which then can support emission reductions. For the midstream sector, Brown *et al.* (2023) concludes that there are challenges to the use of alternative technologies and additional scientific investment is required to better characterize methane emissions to support reduction activities.

Response II-5-21: EPA acknowledges the support of the alternative technology program.

Comment: Commenter (2316-ABB) indicates that with today's commercially available technology, monitoring and collection of comprehensive data characterizing methane leaks can be done quickly and efficiently. For example, ABB's methane leak detection equipment includes an automated documentation process that can record rigorous data efficiently and cost effectively without, as older methods require, expensive calibration to validate measurements. Data collection is no longer a prohibitive, time-intensive, laborious exercise. More importantly, owners and operators can feel comfortable that their interests are properly and accurately represented to federal, state, local, and tribal authorities.

Response II-5-22: EPA acknowledges the support of the alternative technology program and agrees that advanced technology should include sufficient documentation so that the systems can be appropriately audited. As explained in Section X.B.3 and XI.B.3 of the preamble of the rule, EPA has revised and expanded the information that entities must submit to the EPA when requesting an advanced methane detection technology test method.

Comment: Commenter (2213-Occidental (Oxy)) supports EPA's efforts to streamline the process for obtaining approval to demonstrate compliance using advanced measurement technologies. The commenter explains that they are actively engaged and have participated in numerous technology pilots in the pursuit of supplementing our LDAR capabilities, including fixed monitors, drone-mounted cameras, fixed-wing aircraft surveys, and satellite surveys.

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<sup>14</sup> Wang, J. L.; Daniels, W. S.; Hammerling, D. M.; Harrison, M.; Burmaster, K.; George, F. C.; Ravikumar, A. P. Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting. *Environmental Science & Technology* 2022, 56, 14743–14752.

<sup>15</sup> Daniels, W. S.; Wang, J. L.; Ravikumar, A.P.; Harrison, M.; Roman-White, S.A.; George, F.C.; Hammerling, D.M. Towards Multi-Scale Measurement-Informed Methane Inventories: Reconciling Bottom-Up Inventories with Top-Down Measurements using Continuous Monitoring Systems. DOI: 10.26434/chemrxiv-2023-jp5nt. Pre-print can be found at: <https://chemrxiv.org/engage/chemrxiv/article-details/63e526b9cfb27a31f7c0a6c>.

<sup>16</sup> Brown, J.A.; Harrison, M.; Rufael, T.; Roman-White, S.R.; Ross, G.B.; George, F.C.; Zimmerle, D. Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities. Pre-print. DOI: 10.26434/chemrxiv-20230dq01m. Pre-print can be found at: <https://chemrxiv.org/engage/chemrxiv/article-details/63e6b8aafcfb27a31f8ec5b9>

The commenter deploys drones at several of their oil and gas production facilities. At their DJ basin facilities, the commenter uses drones to survey thousands of wellheads as part of a voluntary initiative to reduce emissions. In addition, the commenter surveys wellheads, facilities, and pipeline segments across U.S. operations with fixed-wing aircraft, deploying both broad-coverage campaigns and individual asset surveys. The commenter participates in The Environmental Partnership and its collaborative efforts to better understand and utilize the capabilities of remote sensing technologies that are being developed. A summary of The Environmental Partnership's efforts and learnings can be accessed at <https://theenvironmentalpartnership.org/collaboration-on-remote-sensing-technologies/>.

These innovative LDAR technologies show great promise as tools to supplement traditional LDAR methods. For instance, aerial surveys – both fixed-wing and satellite – allow operators to rapidly inspect large geographic areas, including remote sites, pipelines and gathering lines, that cannot readily be traversed at ground level and elevated equipment such as columns or towers at facilities. Fixed monitoring stations allow for operators to continuously gather monitoring data, creating additional opportunities to identify and address leaks that may otherwise not be identified until a periodic survey is conducted using currently approved LDAR inspection methods. These benefits can assist operators and inspection and maintenance personnel in efficiently and timely directing resources and response efforts to high-priority sites, with less time spent traveling to remote locations that could be covered by fixed monitors or remote sensing.

Response II-5-23: EPA acknowledges the support of the alternative technology program.

Comment: Commenter (2348-Energy Workforce & Technology Council (EWTC)) explains that since 2018, a team has been utilizing drones equipped with methane detection cameras and sensors in the Permian Basin. It has conducted over 1,000 inspections using drones and drone mounted sensors, combined with an artificial intelligence (AI) enabled software platform. This effort is contributing to meeting an operator's goals of maintaining methane emissions intensity below 0.2% by 2025 and meeting the requirements of the Oil and Gas Methane Partnership (OGMP) 2.0 framework.

Commenter (2348-EWTC) notes that since 2018, there has been commercially available continuous monitoring using a sensor network strategically placed at an oil or natural gas production site to monitor for emissions. Industry-wide, there are at least 5 million sensor operation hours for continuous monitoring, providing years of reliable and actionable emissions data for operators. The real-time and historical trend data available from continuous monitoring has provided many advantages in data science and process automation for operators including new levels of emissions visibility and how emissions correlate to the operational schedules and processes. Ultimately this not only provides a better source of information to help prioritize repair efforts, but also significantly shortens the time between initial detection and repair.

Commenter (2348-EWTC) adds that there is also gas cloud imaging (GCI) system in Europe to provide automated and continuous monitoring for leaks of dangerous and polluting gases such as methane at oil and gas, chemical and power generation facilities across the continent. The Mini GCI systems can be placed throughout an industrial facility to continuously monitor for gas leaks

and provide alerts as soon as they occur. The system provides facility operators with an easy-to-interpret, colored visualization of the gas plume type, location, direction, size and concentration. This allows for an earlier and more effective response before leaks have the chance to grow into bigger emissions or safety issues.

Response II-5-24: EPA acknowledges the support of the alternative technology program.

Comment: Commenter (2251-NAM) believes EPA should educate all stakeholders interested in methane (including those parties during the Title V permitting renewal process) about the availability of new methods that save valuable time by minimizing false positives as well as false negatives. EPA needs to assure the public that the wider choices in technology options by producers is the most cost effective and accurate method to find the methane and fix the leaks.

Response II-5-25: EPA is technology agnostic in the final rule. As explained in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA will post all technologies that are approved for use under §60.5398b(d) on EPA's Emissions Measurement Center webpage.

Owners and operators may investigate and choose the technology that best meets their needs from those listed or request an alternative test method for advanced methane detection technology.

Comment: Commenter (2309-Planet) states that current approaches to measure methane emissions at the scale of individual facilities – focused on detection of intermittent activity – present challenges especially in terms of transparency, accuracy, scalability, and cost. The commenter is working to overcome technological barriers to enable accelerated action to reduce methane emissions with plans for a new, groundbreaking hyperspectral satellite constellation called Tanager, expected to begin launching in 2023. The commenter's hyperspectral mission is designed to measure energy in the visible through shortwave infrared wavelengths (400-2500 nm) in over 400 spectrally contiguous bands with 30-meter ground sample distance (GSD). This capability can support the identification of methane emissions at the facility scale, along with a myriad of other applications to improve life on earth spanning across areas such as biodiversity, water quality, land use, national security, agriculture, and more.

Commenter's (2309-Planet) hyperspectral mission brings the promise of ushering in a new era of increased transparency and accountability by providing rapid methane leak detection for super emitters, while our partner Carbon Mapper is developing a global portal to enable wide adoption and transparency, providing a trusted certification chain underpinned by our public-private partnership.

The commenter's (2309-Planet) methane-specific hyperspectral offering could enable users to identify and quickly address methane plumes emanating from specific facilities. These capabilities can be tasked to assist in infrastructure surveys or as a monitoring capability engaged at regular user-driven cadences. The satellite-based technology is intended to balance coverage and sensitivity, covering enough area with a frequency to meet end user needs while providing the sensitivity needed to find facility-level leaks. This would provide federal, state, and local

governments with the tools to measure point-source methane emissions and also support industry in monitoring and measuring their own emissions to enable remediation and prevention.

Commenter (2309-Planet) states EPA should support the leveraging of satellite technologies to fill data gaps which have prevented more widespread identification, mitigation, and prevention of methane emissions. The commenter's satellites orbit the Earth every day collecting consistent data which can be used to gain insights into emissions happening around the world. This global coverage includes remote locations in all 50 states and every municipality across the country. Tanager data products could provide more timely data to identify the source of and support quantification of methane emissions, track mitigation progress, and verify project completion. This facility-level data is needed to enable actionable decisions by industry and government alike.

Response II-5-26: EPA agrees that emissions data from satellites provide value in identifying very large emissions events.

See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology. Additionally, see responses in Volume II, Chapter 14 for responses related to technology use in identifying super-emitter events.

Comment: Commenter (2419-Exploration Robotics Technologies, Inc. (Xplorobot)) describes that it has developed a component-level solution for detection and quantification of methane emissions in oil and gas facilities. The commenter's solution provides a three-dimensional (3D) map of methane concentration, makes visible emissions that may otherwise be invisible to the naked eye on a 3D model of the equipment, identifies the emission's source to the component level, calculates the methane concentration as a function of the distance from the emission's source and quantifies the emission rate based on an industry-standard dispersion model. The commenter's clients use the Xplorobot solution to detect and quantify emissions and to verify the effectiveness of the mitigation steps.

Commenter (2419-Xplorobot) indicates that in response to operators' concerns, the commenter designed a solution such that it does not require a certified inspector to detect, visualize and quantify methane emissions. The solution can be deployed by operators as part of their routine duties, providing savings not only on the hourly rate of the personnel that deploys the solution, but also saving incremental driving or helicopter flying time, given that the solution is deployed as part of field/pad visits to address issues of daily operations by the personnel who operate the fields/sites. Implementation of the commenter's solution is viewed by their clients as the means to comply with the new EPA requirements for cadence and accuracy of methane inspection in a labor and cost-effective manner. It is also considered as an enabler for certification of "clean gas" production for low production wells that cannot afford quarterly OGI inspections or installation of continuous monitoring devices.

The commenter's technology has been validated in laboratory experiments at the Lawrence Berkeley National Laboratory in November of 2022 and January of 2023. Accuracies of methane emissions rate quantifications down to 0.1 kg/hr were achieved. In January of 2023, field

experiments at Methane Emissions Technology Evaluation Center (METEC) achieved a 100% rate of emissions detection on Pads 1, 4 and 5 and are now in the process of validating the quantification accuracy against the known rates of the emissions.

Response II-5-27: EPA acknowledges the commenter's support for advanced methane detection technologies. EPA is providing a pathway for owners and operators to utilize advanced methane detection technologies at well sites, centralized production facilities, and compressor stations as part of the final rule. See discussion in section X.B of the preamble to the final rule which details EPA's final standards related to advanced methane detection technology.

## **5.2 Multi-Layer/Combination of Technologies**

Comment: Commenters (2235-SLB, 2284-Kairos, 2326-AXPC, 2388-ExxonMobil, 2391-Chesapeake Energy Corporation (CEC), 2428- American Petroleum Institute (API)) make the argument that EPA should explore the option of deploying a combination of alternative technologies. Commenter (2388-ExxonMobil) urges EPA to ensure the regulations provide as much flexibility to optimize emerging technologies as possible, including the layering of technologies.<sup>17</sup>

Commenters (2235-SLB, 2284-Kairos, SLB, 2326-AXPC, 2428-API) request that EPA consider a multi-layered approach to leak detection that would allow operators to combine multiple detection technologies.

Commenter (2235-SLB) indicates that the proposed matrices do not provide guidance on deployment of combinations of alternative technologies. Deploying alternative technologies in combination can allow the complementary strengths of the different technologies to be combined in practice. More effective monitoring can occur in many situations if different technologies are combined. Examples exist of how periodic screening technologies and continuous monitoring technologies can be deployed in combination to achieve particularly effective monitoring.<sup>18</sup> Additionally, the matrices do not provide guidance on customized emissions distributions or edge situations between the five frequency versus threshold scenarios presented in each table.

Response II-5-28: EPA agrees with the commenters that owners and operators should be able to use one or more alternative test methods for advanced methane detection technology to conduct

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<sup>17</sup> See Cardoso-Saldaña FJ, Tiered Leak detection and Repair Programs at Oil and Gas Production Facilities, ChemRxiv. Cambridge: Cambridge Open Engage (2022). "Methane emission rates originating from oil and gas production facilities are highly skewed and span 6-8 orders of magnitude. Traditional leak detection and repair programs have relied on surveys with handheld detectors at intervals of 2 to 4 times a year to find and fix emissions, however this approach may lead to leaks being active for the same interval independently of their magnitude. In addition, manual surveys are labor intensive. Novel methane detection technologies offer opportunities to further reduce emissions by quickly detecting the high emitters, which account for a disproportionate fraction of total emissions."

<sup>18</sup> <https://chemrxiv.org/engage/api-gateway/chemrxiv/assets/orp/resource/item/636d4595afea7fcd1c9f5f67/original/tiered-leak-detection-and-repair-programs-at-oil-and-gas-production-facilities.pdf>.

periodic screening. Sections X.B.1 and XI.B.1 of the preamble to the final rule include a discussion on the use of multiple technologies with the periodic screening matrices.

Owners and operators could use periodic screening technologies to enhance continuous monitoring systems by using these periodic screening technologies to keep emission rates from exceeding the action levels for the site. For work practice standards other than those included in the final rulemaking, including the use of different inspection frequencies, owners and operators still have the capability to request an AMEL. Entities requesting an AMEL would be required to provide a demonstration of equivalency as part of the AMEL application.

Comment: Commenter (2226-Thermo Fisher) understands that lower-producing wells may find the economics of procuring the measurement and monitoring equipment and resources challenging. As developers and suppliers of measurement and monitoring equipment, further information on who will be deciding the type(s) of technology used to measure gas leaks at well sites will help inform the commenter and other companies in our industry of any potential need for additional technical assistance or technical information. The commenter recognizes there are many measurement and monitoring technology options available to in-house oil and gas personnel and third-party contractors and selecting the correct equipment for specific needs and environmental conditions is key.

Response II-5-29: EPA has provided flexibility in the final rule for owner and operators to choose the appropriate detection platform for their methane detection surveys by finalizing matrices that tie the frequency of inspection to the method's minimum detection threshold. Owners and operators complying with the alternative fugitive emissions standards using advanced methane detection technologies may choose any approved (or multiple approved) methods to conduct periodic screening events or continuous monitoring.

Comment: Commenter (2448-Project Canary) recommends EPA consider whether additional combinations of detection limits and sample frequency detections can enable a broader range of technologies if they can demonstrate equivalency to EPA's determined BSER. For example, EPA could include additional frequencies and combinations of technologies to encourage the deployment of technologies that can demonstrate equivalency with BSER.

Response II-5-30: EPA acknowledges the commenter's recommendation. As explained in sections X.B.1 and XI.B.1 of the preamble to the final rule, we have included more flexibility to use multiple technologies in the matrix framework in the final rule; however, we are not expanding the framework as part of this final rule.

Comment: Commenter (2316-ABB) notes that given today's commercially available technology, it supports the regular monitoring of ALL well sites (and continuous monitoring, when appropriate). However, to reach the leak detection and reduction goals stated in the proposed and supplemental rules, the EPA should focus on the methane leak rate rather than the use of specific leak detection technology. For example, legacy technologies such as OGI, are unable to provide the necessary performance, reliability, and sensitivity needed to adequately meet current challenges. When sufficiently advanced leak detection technology is employed, the owner/operator will be able to effectively inventory all fugitive methane emissions and



subsequently prioritize their remediation based on the volumetric rate (flux) estimations. This will allow the largest emitting sources to be addressed most quickly and most efficiently.

Response II-5-31: EPA acknowledges the commenter's recommendation and agrees that new technology may have the ability for owner or operators to meet their emission reductions. As such, we have included a pathway for advanced technology in the final rule. EPA does not agree with the commenter that OGI does not provide sufficient sensitivity, performance, and reliability in identifying leaks from this sector. OGI continues to be the BSER for monitoring fugitive emissions affected and designated facilities.

Comment: Commenter (2284-Kairos) notes a key missing provision from EPA's proposed leak detection matrix is a pathway for combinations of technologies to be used. While it may be difficult to proactively imagine every possible technology combination and include it in the Proposed Rule, there are some clear examples that EPA should evaluate and develop pathways for approval.

Commenter (2284-Kairos) states the first case is related to seasonal conditions which may inhibit certain survey approaches. For example, aerial screening surveys may be limited in certain regions during certain times of the year due to weather constraints. Winter in places like North Dakota or Wyoming can be long and harsh, and aircraft may not be able to safely operate, particularly under the more frequent survey programs (*e.g.*, monthly surveys at 30 kg/hr). To remedy this and allow for regions with harsher conditions to benefit from advanced technology screenings, the commenter suggests EPA consider ways to allow OGI surveys or other combinations of technologies, like continuous monitoring systems, to be used in combination with aerial techniques. To illustrate, one possible program might involve using monthly aerial screenings March through November, with an OGI survey for the December-February timeframe. As EPA's modeling has made clear, a 1:1 trade out of inspection methods won't necessarily be equivalent, so three monthly OGI surveys during that three-month timeframe would create additional expense and complexity that isn't necessary to achieve equivalence with the BSER.

Commenter (2284-Kairos) continues, the second case would be situations where individual screening surveys are delayed or perhaps canceled due to extreme weather. For instance, a major hurricane could impact Gulf Coast operations and potentially close airfields for several weeks or longer, depending on the severity of damage. The probability of a situation such as this impacting a survey schedule might be higher for higher frequency programs.

Commenter (2284-Kairos) recommends the EPA allow for combinations of advanced screening surveys and other technologies, such as periodic OGI surveys, to be used to increase flexibility for how and where advanced technologies can be deployed. Once a methodology has been established, this could be expanded to other leak survey methods. EPA should establish a process for how to proceed with leak detection programs in situations where a single survey may be impacted by extreme weather or other force majeure.

Commenter (2284-Kairos) states EPA's current work practice for remote screening technologies dictates that when an operator receives a reported aerial detection, they must visit the site and

conduct a comprehensive OGI screening survey of that site. The commenter believes the general work practice of using ground observation in conjunction with remote screening is appropriate, as it's the most consistent and measurable way to identify and eliminate emissions. The commenter believes this proposed work practice can be strengthened through minor modifications.

Commenter (2284-Kairos) is also aware of arguments that in some instances a reported aerial detection is enough to determine a corrective course of repair, or that survey results can be dismissed as being tied to a process event through SCADA without a ground visit. This may be true in some instances, but in the commenter's extensive experience of conducting hundreds of thousands of facility measurements, they have found that there can be multiple disparate sources on a pad or single process unit (*e.g.*, multiple components on a vapor recovery system) that combine into a single "plume" from an aerial measurement system. This is true even for the highest resolution aerial imagery. The commenter is also aware of instances where incorrect assumptions regarding the nature of an airborne detection led to delayed follow up inspection and mitigation, and instances where SCADA data was unable to fully characterize deviations that led to significant emissions. Without ground truth verification, it's possible for emissions to be improperly diagnosed or only partially repaired.

Commenter (2428-API) believes a combination of technologies approach recognizes that each leak detection technology has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

Commenter (2428-API) states that by allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

Commenter (2428-API) indicates that a multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a

continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry prepublication paper.<sup>19</sup> The commenter provides in their comment letter Figure 1. Multi-layered approach for leak detection showing satellite, aerial survey, and continuous monitoring.

Commenter (2428-API) adds that EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. The commenter has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- Add continuous monitoring and satellite technology as options directly in the matrices in combination with the periodic survey with and without annual OGI.
- Include an additional optional and flexible framework independent from the periodic screening matrices and case-by-case alternative means of emission limitation (AMEL) process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA approved modeling.

Commenter (2428-API) believes that this flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

Response II-5-32: EPA has included the suggested layered approach in the final rule as described in Response II-5-28. While not discussed in the previous response, the layered approach allows the owner or operator to choose the most appropriate technology for the time of year. Additionally, the final rule allows the owner or operator at any time to conduct an OGI survey in lieu of conducting a required periodic screening event.

Comment: Commenter (2391-Chesapeake Energy Corporation (CEC)) supports EPA's continued encouragement of emerging technologies that enhance detection of potential emissions from the natural gas sector. Deploying a broader suite of advanced technologies is an important part of achieving additional cost-effective emission reductions. Still, the commenter urges EPA to expand its approach to provide greater flexibility and to ensure compatibility with and encourage the development of future technologies.

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<sup>19</sup> Cardoso-Saldaña FJ. Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv.

Commenter (2391-CEC) supports alternatives for periodic screening and continuous monitoring, however, neither option accounts for companies using multiple technologies as part of a robust methane monitoring and detection program. The commenter is singularly committed to enhanced methane monitoring and achieving methane reductions from its dry gas assets. The company now has more than 2,000 continuous methane monitoring devices operating today. Over this, it layers satellite imagery with periodic aerial Gas Mapping LiDAR scans to quickly identify potential emission events. EPA's proposed periodic screening alternatives recognize that activities of a certain frequency that meet the minimum detection thresholds are equivalent to the OGI surveys and AVO inspections otherwise required by the proposed regulations. But neither the matrix nor the proposed continuous monitoring framework says anything about the equivalency of a combination of alternative technologies. This omission fails to serve EPA's goal of incentivizing new technologies and makes it difficult for the matrix to keep pace with future alternatives as they become available or as current options become more cost effective.

Commenter (2391-CEC) believes that in order to correct this, EPA should identify and implement a methodology that operators can use to determine the equivalency of a particular combination of technologies. Currently, the only other available avenue is CAA section 111(h)(3), but AMELs are simply not a workable approach for new technologies. The AMEL process has historically been extremely complicated due to onerous regulatory requirements, with no alternative certifications being granted thus far. Identifying a way to determine the equivalency of various technologies and make use of a combination of alternatives outside of the statutory AMEL process will further enhance advancement and innovation in this space and allow operators to capitalize on these technologies to reduce emissions cost effectively.

Response II-5-33: In the final rule, EPA has confirmed that multiple technologies could be used within the existing matrix framework and because the frequency of the monitoring is tied to the least sensitive technology, we recognize that approach could result in greater emission reduction if owners or operators use technology with better sensitivity in their monitoring.

### **5.3 Screening Frequency/Minimum Detection Threshold**

Comment: Commenter (2346-Encino Environmental Services, LLC (Encino)) believes EPA should establish both technology-specific and site-specific minimum detection thresholds<sup>20</sup> for all sensors, cameras, and advanced methane sensing technologies. Representative baseline detection limits established from clear baseline procedures that reflect actual emissions scenarios will allow operator flexibility for various processes, sources, or sites. Currently, all sensors, cameras, and meters are tested the same, but each has a unique detection ability that the testing does not account for with current commonly used procedures.

First, commenter (2346-Encino) indicates that all technologies are not created equal, each type of methane monitoring tool can have its own unique skill set (and utility) that if tested and evaluated in the same manner would discourage technological advancement. For example, 500

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<sup>20</sup> Minimum Detection Level: Super Emitter 100 kg/hr; InfraRed Only may include camera 500 ppm; Short term action level 7-day average calculated each day; Long term action level 90-day average calculated each day; Wellhead only 15 kg/hr; Well sites with other equipment and compressor stations 21 kg/hr; Fugitive emission monitoring wellhead 1.2 kg/hr; Fugitive emission monitoring for well sites 1.6 kg/hr.

ppm (methane) (with EPA Method 21) allows for granular leak detection. However, there are several limitations: (a) it is an intermittent inspection program, (b) time lag regarding repairs and verification of the sustainability of each repair (resurvey), and (c) produces only a concentration value (not a mass or volumetric rate) while advanced methane technologies can establish mass emission and flow rates that can achieve the proposed 1.2 kg/hr MDL. Thus, as technology advances, improved detection results will decrease MDLs and improve the identification of methane emissions over time.

Second, commenter (2346-Encino) indicates each detection technology can have unique advantages and disadvantages. With each type of source releasing varied emissions at distinct levels, there are specific tools and procedures for monitoring these complex scenarios. Technology is available that can establish normal operating baselines for each source and monitor for irregularities that exceed these (pre-established) baselines. These action levels are sufficient for NSPS compliance demonstration; therefore, these action levels should be accepted for emission factor development (*e.g.*, permitting activities, and emission inventories).

Third, commenter (2346-Encino) indicates that sites are a combination of sources and technologies that are varied across specific monitoring situations. As technology improves the combinations of emission sources at a site will be quantifiable in a manner that will allow for real-time monitoring and detection of conditions that exceed EPA regulations on a monthly, daily, and potentially even hourly basis.

Commenter (2346-Encino) notes that methane intensity is not an accurate measurement of a site's action level. Methane intensity is commonly established by using emission factors, and vetted production data, neither of which includes analysis of the actual emissions profile of those sites. Accordingly, the correct measurement should be measured averages over time. For example, when construction projects increase emissions estimates of methane intensity the impact will not change, however, measured average projects will naturally fall within true action levels.

Response II-5-34: EPA acknowledges the commenter's support of continuous methane monitoring approach in the rule. We agree that as the measurement systems mature, sensitivity and time resolution of the measurements will improve.

Comment: Commenter (2406-Energy Emissions Modeling and Data Lab (EEMDL)) states recent work on multi-scale methane measurements indicates the importance of survey frequency in detecting intermittent large emitters. While the modeling referenced in this comment limited large emitter duration to 5 days, field observations indicate significantly shorter durations (in the order of minutes to hours) are possible. Furthermore, technologies used in this study (aerial- and drone-based screening) were able to attribute emissions to particular equipment. Identifying the emitting component for future repair only required follow-up OGI screening on the equipment group identified by the aerial system. Thus, the spatial resolution of the site-wide screening method may enable direct, equipment-specific emissions and will not require follow-up OGI survey on the entire site.

Response II-5-35: See discussion in section XI.B.1.c of the preamble to the final rule which details EPA's final standards related to spatial resolution of advanced methane detection technology.

The final rule also outlines different follow-up procedures based on the spatial resolution, or localization capabilities, of the technology. EPA has expanded on these details in Response II-5-19.

## **5.4 Compliance Issues/Deviations Detected by Advanced Technologies**

Comment: Commenters (2284-Kairos, 2298-Pioneer, 2333-LongPath, 2336-Kuva Systems (Kuva), 2348-EWTC, 2402-Differentiated Gas Coordinating Council (DGCC), 2405-Bridger, 2428-API, 2440-Nevada Nanotech Systems, Inc. (NNS)) express concerns that emissions detected using advanced technologies could be deemed compliance violations.

Commenters (2284-Kairos, 2298-Pioneer, 2333-LongPath, 2348-EWTC, 2402-DGCC, 2405-Bridger, 2440-NNS) ask if operators discover a process failure, such as a malfunctioning flare or other failed control device using an advanced technology, and the detection is fixed within that specified period, are the owners/operator liable for any violation for a failure of the control device?<sup>21</sup> EPA should ensure the Final Rule creates an incentive to locate and repair emission sources by creating a compliance pathway for process malfunctions detected by innovative technologies.

Response II-5-36: EPA disagrees with commenters that a change in emission standards is necessary to incentivize the adoption of advanced technologies. EPA recognizes that emissions detected by advanced technologies could result in deviations of emission limits applicable to an emission source. [See Section X.B and XI.B of the preamble of the rule]. But owners and operators have a legal duty to operate any affected facility in compliance with applicable standards, including emission limits, and affected facilities must be in compliance with the requirements of the rule during all times. Frequent detection of excess emissions by advanced monitoring technologies should not occur if control devices and other emission sources are adequately engineered to continuously meet applicable emission standards. Allowing "grace

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<sup>21</sup> For example, in the Supplemental Proposal preamble regarding Control Vent System (CVS) requirements, EPA notes that "based on comments received on the November 2021 proposal, there appears to be confusion whether the proposed no detectable emissions (NDE) standard would be an emissions limit or a work practice standard. For example, one commenter stated that as written, the NDE standard would be a work practice standard because ' [a]s with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.' This interpretation of the standard is not correct. In fact, CVS must be designed and operated to route all gases, vapors, and fumes to a control device or to a process, which is defined as an emission limit of NDE. The corrective actions (in the form of the repair provisions) are provided to ensure that owners and operators bring the CVS back into compliance with the NOE emission limit as quickly as possible." EPA should clarify whether repairing the leak qualifies identified with advanced technology qualifies as complying with a work practice or whether it is a deviation under the rules.

periods” for repair during which compliance with emission limits is not required would be inconsistent with and weaken the emission limits determined to be the best system of emission reductions because it would no longer require continuous compliance. “Grace periods” would further disincentivize efforts to address the underlying causes of violations and take corrective measures to ensure continuous compliance with applicable standards. If advanced technologies monitoring results in the identification of violations of emission limits at non-fugitive components, corrective actions should be taken as soon as possible to address the failures. Further actions may also be necessary to address the underlying causes of the violations and avoid future emission detections by the advanced monitoring technologies. For example, where advanced technologies indicate emissions from covers and closed vent system that are not fugitive components and are required to achieve a no identifiable emission standard, an engineering evaluation could be warranted to confirm the system is adequately designed to meet the no identifiable emission standard.

Comment: Commenter (2333-LongPath) indicates that continuous monitoring is an effective means of detecting emissions from these types of systems, which can be intermittent in time or otherwise difficult to detect with AVO or OGI. Operators should be incentivized to use continuous monitoring in either the periodic screening matrix or under the continuous monitoring provisions, for example by not characterizing caught leaks as violations, but instead incentivizing operators to more rapidly find and repair the underlying problems. Because site-wide continuous monitors can measure all emissions but may not always be deployed so as to localize emissions, the thresholds for exceeding total site-wide total baseline emissions by the action levels determined in the matrix (periodic screening or continuous) should trigger an investigative analysis from desktop and, if needed, field, to identify the cause of the emission. That is, there should not be changes to the proposed action thresholds, so that all technology types can participate equally.

Commenter (2336-Kuva) states that due to spatial and temporal coverage of advanced technologies, different emission sources may be revealed that could represent compliance issues as compared to standard OGI surveys. Examples of such sources include compressor engine incomplete natural gas combustion and control devices issues. According to the commenter, the proposed rule inadvertently disincentivizes the adoption of advanced technologies by penalizing more effective detection of emissions with a burden of an often unnecessary full-site OGI follow-up survey. The commenter believes the final rule should encourage, rather than penalize, the efficient and effective detection of emissions. The commenter therefore advocates for critical revisions to the Proposed Rule that will incentivize the detection, characterization, and mitigation of emissions by ensuring that (a) the follow-up response to emissions detected with advanced technologies is appropriate to the emission and (b) a compliance pathway is provided for operators to correct detected emissions that would otherwise result in a compliance violation. The commenter urges the final rule to provide an efficient and explicit compliance pathway for addressing such compliance issues detected by advanced technologies that enables operators to avoid a violation if the source is appropriately mitigated.

Response II-5-37: EPA disagrees with commenters that a change in emission standards is necessary to incentivize the adoption of advanced technologies. EPA recognizes that emissions

detected by advanced technologies could result in deviations of emission limits applicable to an emission source. [See Section X.B and XI.B of the preamble of the rule].

Comment: Commenter (2428-API) states that emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the “no identifiable emissions” standard provided work practice standards are fully implemented.

According to commenter (2428-API), emissions detected from covers and closed vent systems are not necessarily violations of the “no identifiable emissions” standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to BSER, but it also disincentivizes the use of alternative technology.

Response II-5-38: EPA disagrees with the comment. While some CVS components are fugitive emission component, a no identifiable emission standard applies as an emission limit to covers and non-fugitive component CVS. The no identifiable emission standard, where applicable, is an emission limit and not a work practice standard, and owners and operators have an obligation to comply with that emission standard where it applies. Because covers and CVS are required to be designed and operated with no identifiable emissions, indications of emissions from these sources could result in violations of the emission limit applicable to CVS where the CVS is not a fugitive emissions component. While the final rule provides different options for demonstrating compliance with the operation of the cover and CVS no identifiable emissions standard, any detection of emissions, including during the use of alternative monitoring technology, is an indication of detected emissions that may be a violation of the no identifiable emission standard. While applicable repair, delay of repair or exceptions for unsafe and difficult to inspect equipment may appear to condone a “grace period” during which compliance with an emissions limit is not required, because the no identifiable standard in the final rule is established as an emission limit, operation in exceedance of that limit may be a violation even if the repair provisions are followed.

EPA further disagrees with commenters that a change in emission standards is necessary to incentivize the adoption of advanced technologies. EPA recognizes that emissions detected by advanced technologies could result in violations of emission limits applicable to an emission source. But owners and operators have a legal duty to operate any affected facility in compliance with applicable standards, including emission limits, and affected facilities must be in compliance with the requirements of the rule during all times. Frequent detection of excess emissions by advanced monitoring technologies should not occur if control devices and other emission sources are adequately engineered to continuously meet applicable emission standards. Allowing “grace periods” for repair during which compliance with emission limits is not required would be inconsistent with and weaken the emission limits determined to be the best system of emission reductions because it would no longer require continuous compliance.



“Grace periods” would further disincentivize efforts to address the underlying causes of violations and take corrective measures to ensure continuous compliance with applicable standards. If advanced technologies monitoring results in the identification of violations of emission limits at non-fugitive components, corrective actions should be taken as soon as possible to address the failures. Further actions may also be necessary to address the underlying causes of the violations and avoid future emission detections by the advanced monitoring technologies. For example, where advanced technologies indicate emissions from covers and closed vent system that are not fugitive components and are required to achieve a no identifiable emission standard, an engineering evaluation may be warranted to confirm the system is adequately designed to meet the no identifiable emission standard.

## 5.5 Follow-up OGI

Comment: Commenter (2305-Williams Companies, Inc. (Williams)) is generally supportive of EPA’s required alternative monitoring frequencies and screening levels. The commenter suggests, however, that monitoring survey and inspection activities in § 60.5398b(b)(4)(ii) (A) through (C) not be triggered when screening levels are exceeded as a result of the following permitted activities:

- Equipment maintenance blowdowns;
- Pig trap blowdowns;
- Emergency blowdowns; and
- Vented equipment emissions.

Response II-5-39: EPA recognizes the input from the commenter. It can be difficult to directly attribute all emissions identified by an aerial survey. While these short-term events can trigger a “hit” from an aerial survey, these events may also mask other leaks at the facility that could have also triggered a “hit” by the aerial survey. As such, we are retaining the requirements to conduct a ground survey when there is a “hit” during an aerial survey as detailed in Section X.B.1 and XI.B.1 of the preamble of the final rule.

Comment: Commenter (2405-Bridger) states the “blanket” follow-up OGI survey for emissions detected by advanced technology in the periodic screening matrix is an ineffective approach to mitigating emissions. Advanced technologies may detect, record, and characterize many emission sources for which OGI follow-up is unnecessary, unhelpful, and/or impractical. A mandatory OGI sweep will create a disincentive for operators to deploy advanced technologies for compliance with the Proposed Rule by causing an undue burden when it is not an appropriate or useful response. Moreover, sending an OGI crew for each detected emission (instead of more effective responses) will also decrease safety. NIOSH / CDC found that in 2017 (and qualitatively similar results in 2015-2016), vehicle accidents for oil and gas extraction related field operations were the leading cause of fatalities (42%). Of these, the majority were on roadways to/from/between sites.<sup>22</sup>

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<sup>22</sup> <https://www.cdc.gov/niosh/topics/fog/data2017.html>.

Commenter (2405-Bridger) argues the mandatory OGI follow-up is particularly burdensome for the more sensitive detection tiers because more sites with emissions will be identified by the advanced technology leading to a greater OGI follow-up burden. For the 1 kg/hr (90% POD) tier, the commenter will detect emissions on more than 50% of sites in the Permian Basin and OGI crews would be required to be deployed to each of these sites. Therefore, as written, the Proposed Rule disincentivizes better detection sensitivities.

Commenter (2405-Bridger) adds, compared to a universal OGI follow-up requirement, a better approach to responding to emissions will often involve investigative analysis using a combination of advanced technology data (Figure 1), compressor runtime data, process control / SCADA data, maintenance activity logs, AVO inspection, and prior screening results. The spatiotemporal data from advanced technologies (including replicate infrastructure scans) can be especially useful in this process if the advanced technology can precisely localize the emission, identify the emission as normal or abnormal, identify the emission as intermittent, and/or directly identify its cause.

Commenter (2405-Bridger) states intermittent emissions are one scenario where OGI follow-up may be an ill-suited response. For example, process upsets may cause over pressurization of cover/closed vent systems resulting in emissions that are detected during an infrastructure scan but are no longer present according to a successive scan to evaluate persistence. Because of intermittent behavior, follow-up OGI has a reduced likelihood of confirming the emission and would not provide additional helpful information in either case. Commenter (2405-Bridger) adds meanwhile, suitable advanced technologies will already have clearly identified the emission point. An investigation into the process upset conditions that caused the emission could help elucidate necessary updates to system parameters that would mitigate future emissions. In this example, an OGI follow-up does not increase emissions reductions and causes undue burden on the operator. For intermittent emissions, investigative analysis is the appropriate requirement instead of a blanket OGI follow-up requirement.

Commenter (2405-Bridger) states for normal process emissions that are detected by alternative emissions monitoring, OGI follow-ups may be ineffective. In the case of permitted emissions from natural gas fired internal combustion engines and control devices, OGI may have difficulty differentiating between normal and abnormal operation, which, for control devices, was recognized in the Proposed Rule.<sup>23</sup> However, these emission sources are regularly detected by advanced technologies even when normally operating. To provide fair and consistent rules, the EPA should not require onsite follow up in response to emissions detected during periodic screening that correspond to normal process emissions operating within permitted emission bounds. Separate performance standards in the Proposed Rule already apply to these types of emission sources. If permitted process emission are detected and conclusively identified, then no response other than recordkeeping and reporting should be necessary.

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<sup>23</sup> “One commenter stated that emissions resulting from noncompliance with control device requirements should not...be defined as fugitive emissions...since control devices are inherently designed to have emissions, even when well operated, it should be expected that some amount of methane and VOC would be detected during an OGI survey for fugitive emissions. The EPA agrees that control devices should not be treated as fugitive emissions components...”

Response II-5-40: As noted previously, it is often difficult to tell if a “permitted” emission event may mask other fugitive emission releases. It is very difficult to identify all of the different scenarios in the regulation to specify the criteria of a survey technique (with respect to the detection value and geographical specificity), the type of investigative analysis that must be conducted, the specific results that would be needed to not send an OGI crew. We have sought to develop an enforceable rule that directly allows the use of alternative technologies.

However, in an effort to incentivize technology with tighter spatial resolutions, which includes those technologies that are typically more sensitive, emissions coming from process regulated through other programs (*e.g.*, methane slip from a RIE emission combustion exhaust) would not trigger a follow-up, so long as the emissions are documented, and the technology used is spatially resolved enough to distinguish those emissions from a fugitive component and/or covers and closed events systems.

Comment: Commenter (2305-Williams) recommends §60.5398b (b)(4)(ii)(D) be added to provide direct repair of a fugitive emissions component that is conclusively identified using an alternative screening method, without prompting a full fugitive emissions survey of the effected facility.

Response II-5-41: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every “hit” from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey.

However, in an effort to incentivize the use of advanced methane detection technology in the final rule and to acknowledge that for those technologies with proven spatial resolution, the final includes the ability to conduct a more targeted follow-up when using certain approved methane detection technology.

Comment: Commenter (2458-MiQ) is very concerned that the current construction of the supplemental proposed rule would create disincentives to the adoption and/or use of advanced monitoring technologies. The monitoring framework included in the supplemental proposal for the use of advanced monitoring technologies would entail a follow-up monitoring survey of the entire facility through the use of OGI technology if an advanced monitoring technology identifies a leak. Under this regulatory construction, the OGI survey serves as the monitoring ‘floor’ for a compliance monitoring scheme. That is, even where an approved advanced monitoring technology system may have identified a leak, OGI monitoring technology must be used as a follow-up. Not only must it be used, OGI technologies must – according to the current proposed regulatory language - be used to survey the entire facility. This is the case, even if the advanced monitoring technology detection had identified a localized source. The proposed regulations state:

“You must conduct a monitoring survey of the entire fugitive emissions components affected facility following the procedures in your fugitive emissions monitoring plan. During the survey, you must observe each fugitive emissions component for fugitive emissions.”

Commenter (2458-MiQ) argues this proposed framework would result in a number of disincentives for the use of advanced monitoring technologies – even at the same time that some of these technologies may be more effective than some OGI technologies at identifying sources of fugitive methane emissions. The use of advanced monitoring technologies may be viewed as superfluous and unnecessary because an operator will realize that an OGI survey must be completed in any case if a detection is identified. Additionally, an inefficient use of operator resources and unreasonable incurred costs for being required to do a full facility OGI survey even if the advanced monitoring technology has localized the emission source with a high degree of probability.

Commenter (2458-MiQ) continues, based on these elements, an operator may choose to dispense with the use of advanced monitoring technologies, and simply implement a basic quarterly OGI monitoring program. The result of these disincentives is that an operator may likely make a decision to not adopt advanced monitoring technologies, or to discontinue the use of these technologies. This is especially the case if the methane detection limit (MDL) is lower for the advanced monitoring technology than it is for OGI. The results of this undesirable outcome would include:

- Methane emissions that continue to take place at levels not detectable by the OGI technology in place.
- Methane emissions that occur between quarterly OGI inspections that would have been detected through advanced monitoring technology inspections taking place on a more frequent basis.
- The development of advanced monitoring technology would be hindered. The structural disincentive put in place, were this rule to be promulgated, would significantly limit market interest in developing more effective and sensitive monitoring technologies. As a result, not only would the sector be locked into using [over time] fewer effective technologies, but the nation would also be inhibited in minimizing methane emissions.

In order to address the very problematic construction of the proposed regulations, commenter (2458-MiQ) recommends the following:

1. Eliminate the requirement for a facility-wide follow-up OGI survey and replace it with an OGI survey that is pertinent to the localization uncertainty region of the advanced monitoring technology. If an advanced monitoring technology identifies a leak and has an emission performance of x-meters, with a robust confidence factor, the follow-on OGI survey should be limited to that radius. This will reduce operator costs and could allow resources that would have been spent on a full facility OGI survey to be spent on additional advanced monitoring technology surveys or other methane mitigation activities.
2. If an advanced monitoring technology survey detects an emissions leak and the operator, then identifies the specific emission source through a root cause analysis (or causal examination) the follow-on OGI survey should not be required by the EPA as necessary. The root cause analysis could include SCADA data, maintenance activity logs, advanced monitoring technology data, compressor data, and process control information. In addition to being an unnecessary cost in those situations, the OGI survey may or may not

be able to differentiate between operation types (and therefore the emission source) – whereby a root cause analysis may be able to. If a root cause analysis, as described above, cannot determine the source or reason for the emissions event, the use of a localized OGI survey would be appropriate.

Response II-5-42: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every “hit” from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey. We did not identify equivalencies by only repairing the “big” leaks. Based on our modeling, repairing only the big leaks would not be equivalent to routine ground OGI surveys. We disagree with the commenter that relying on the routine ground OGI surveys would result in poorer environmental outcomes compared to using application of advanced technologies.

Comment: Commenters (2284-Kairos, 2326-AXPC, 2428-API) recommend EPA align alternative screening technology, OGI, and AVO response timeframes.

Commenter (2284-Kairos) believes that the timelines for the Super-Emitter Response Program, various response timelines for alternative screening technologies, OGI, and AVO throughout the rule could benefit from alignment. EPA proposes response time frames ranging from 24 hours (completion of root cause analysis for fugitive emissions caused by failure of a control device) to 30 days (completion of final repairs for most sources of emissions). These varying timelines will create confusion and cause undue burden on owners and operators for what is likely negligible emissions abatement. The commenter recommends a standard 30-day response timeframe for completion of repairs for non-Super Emitter fugitive emissions. As stated previously, FEAST modeling is capable of measuring the impacts of repairs over a range of timeframes and should be used to weigh the costs and benefits of aligning these response timeframes.

Commenter (2428-API) similarly recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, the commenter recommends that repairs be prioritized based on higher detected emissions.

Commenter (2326-AXPC) agrees with API’s comment that follow-up surveys and inspections, including OGI camera inspections should not be required in instances where the source of detected emissions can be identified based on the localization performance of the alternative technology, AVO inspection, and/or other operation data known to the company.<sup>24</sup> And where source-specific attribution can be determined by the alternate technology, no ground-based inspection follow-up should be required – only the potential for corrective action if the emissions

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<sup>24</sup> See API Supplemental Proposal Comments § 3.3.2.

are not authorized. Lastly, EPA refers to ground-based surveys. However, where follow-up is required, EPA's regulations should ensure that operators can utilize drone-mounted, or helicopter mounted OGI for further investigatory analysis.

Response II-5-43: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every "hit" from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey. We did not identify equivalencies by only repairing the "big" leaks. Based on our modeling, repairing only the big leaks would not be equivalent to routine ground OGI surveys.

Comment: Commenter (2391-CEC) believes that to require the operator to conduct a ground-based OGI survey of all fugitive emissions components at the site to identify the source of the emissions can be burdensome and not necessary depending on the technology used.

Commenter (2391-CEC) believes EPA should permit operators to first review their records to see if the source of emissions can be identified without a further survey. The cause may often be apparent in operator logs, SCADA data, and similar records. Where the cause cannot be identified based on other records, an AVO inspection should be allowed as the first response. Only when AVO cannot identify the cause of emissions, should an OGI survey be required.

Commenter (2391-CEC) adds that if—once the record review and AVO inspection have occurred—an OGI survey is still required, EPA should not assume the survey must cover the entire facility. Doing so fails to recognize that some alternative technologies can detect source level emissions. When those technologies are used, surveying the entire facility is simply not necessary to identify the source of the emissions.

Commenter (2391-CEC) suggests that when an OGI survey is necessary, EPA should allow operators the flexibility to conduct the survey using OGI cameras mounted to drones or aircraft as appropriate. Either can be a more effective approach than ground-based OGI but proposed §60.5398b(b)(4)(iv) and §60.5398c(b)(4)(iv) each eliminates these by referring to the OGI survey in an earlier paragraph as "ground-based." EPA should remove this term from both regulations. It is not necessary to refer to the OGI survey as "ground-based" to ensure OGI surveys are conducted at the appropriate distance; the requirements in proposed §60.5397b(c)(7) and §60.5397c(c)(7) are sufficient for this purpose.

Response II-5-44: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every "hit" from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey. We did not identify equivalencies by only repairing the "big" leaks. Based on our modeling, repairing only the big leaks would not be equivalent to routine ground OGI surveys.

Comment: Commenter (2369-ChampionX) notes the current language in the proposal is written to address fixed sensors, which identify that there is a leak in a geographic area. However, when using a manned or unmanned aircraft, a leak can be pinpointed to the exact source of the fugitive emission. This would allow maintenance personnel to repair the leaking component identified during the advanced measurement screening.

Commenter (2369-ChampionX) has demonstrated that an aerial OGI screening from at least 150' can pinpoint small to large fugitive emission leaks. The ability to positively identify a leak for repair negates the need to have an entire site inspected to find the potential leak. The commenter's aerial technology has demonstrated a minimum detection limit that is below the threshold of 30 kg/hr and capable of meeting the Quarterly + Annual OGI minimum screening frequency.

Commenter (2369-ChampionX) notes that the proposed language would trigger a ground monitoring event of all fugitive emission components at the site where the advanced screening survey occurred. The proposed language discourages the use of periodic surveys through advanced screening methods for the following reasons:

1. Many locations are remote and mobilizing an inspection crew in 14 days is challenging.
2. Inspecting hundreds of sources due to one leak is not cost effective.

Using advanced technology such as manned and unmanned aerial systems allow for more sites to be inspected per day, and thus larger leaks can be found quicker.

Commenter (2369-ChampionX) recommends separating the proposed requirements for fixed detectors and aerial OGI advanced measurement technologies. Commenter (2369-ChampionX) recommends removing the requirement for ground monitoring for leaks identified through aerial OGI advanced measurement technologies. The fugitive component repair of the leak identified would be in accordance with the same repair deadlines as those for regular fugitive surveys (*i.e.*, a first attempt at repair within 30 days of the OGI survey and final repair completed within 30 days of the first attempt)

Response II-5-45: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every "hit" from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey. We did not identify equivalencies by only repairing the "big" leaks. Based on our modeling, repairing only the big leaks would not be equivalent to routine ground OGI surveys.

Comment: Commenter (2446-IPAA) recommends three revisions to the use of OGI for "follow-up" survey requirements:

1. Change the full-site follow-up OGI survey requirement to a follow-up OGI survey only over the spatial extent corresponding to the verified localization performance of the detection technology.
2. Exclude from the follow-up OGI survey requirement those emission sources corresponding to normal permitted (*i.e.*, allowable) operating process emissions or emission events that are otherwise confirmed to no longer exist.
3. If any degree of OGI follow-up remains a requirement, a leak detected with aerial technology must be confirmed by a second fly over pass before it is deemed an actionable event that triggers the follow up.

Response II-5-46: The equivalency of the alternative technology matrix is predicated on a ground OGI survey being conducted on every “hit” from an aerial survey, which would cause repairs of small leaks as well as the larger leaks identified during the aerial survey. We did not identify equivalencies by only repairing the “big” leaks. Based on our modeling, repairing only the big leaks would not be equivalent to routine ground OGI surveys.

EPA has allowed for some allowance for when technology is spatially resolved enough to distinguish process emissions from fugitives’ emissions, and in some instances, we have also allowed for more targeted follow-up, but only those technologies with proven spatial resolution and as defined by the EPA. These follow-ups must be conducted using OGI and Method 21 which are sufficiently sensitive enough to pick up the smallest of leaks.

## **5.6 Allow NSPS OOOOa Sources to Comply with NSPS OOOOb**

Comment: Commenters (2360-Devon, 2428-API) ask that EPA allow NSPS OOOOa sources to comply with NSPS OOOOb to use alternative technology for compliance.

Commenter (2360-Devon) encourages EPA to consider mechanisms to enable sources subject to subpart OOOOa, prior to the effective date of 111(d) state or tribal plans under subpart OOOOc, to demonstrate compliance with applicable fugitive emission requirements with any advanced technologies approved under the alternative test method approval process (Proposed OOOOb §60.5398b(d)).

Commenter (2428-API) encourages EPA to consider mechanisms to enable sources subject to subpart OOOOa, prior to the effective date of 111(d) state or tribal plans under subpart OOOOc, to demonstrate compliance with applicable fugitive emission requirements with any advanced technologies approved under the alternative test method approval process (Proposed OOOOb §60.5398b(d)). Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (*e.g.*, aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

Response II-5-47: See discussion in sections IX.C and XI.B.1.a of the preamble to the final rule which details EPA’s final standards related to use of alternative methane detection technologies.

## **5.7 Recommended Changes/Clarifications**

Comment: Commenter (2448-Project Canary) states while continuing to improve, our current understanding of emissions throughout the US is imperfect. EPA’s use of peer reviewed studies to develop the matrix is reasonable and appropriate recognizing the available data when EPA developed the Supplemental Proposal. However, the commenter encourages EPA to consider any



additional recent studies and refine the Final Rule accordingly, to ensure it reflects our up to date understanding of emissions and technology opportunities and constraints. Additionally, given that emissions data will continue to rapidly improve as operators use advanced technology and as EPA implements Inflation Reduction Act funding for methane detection, it will be important to have a regulatory process and expectation that EPA will refine the matrix over time.

First, in addition to evaluating EPA's assumptions and inputs for FEAST with any additional peer-reviewed studies submitted as part of comments or released before the Final Rule, Commenter (2448-Project Canary) recommends that EPA make clear in the Final Rule that it will periodically update the matrix by updating the FEAST modeling and inputs as additional data becomes available. This update can be completed, for example every three to five years, to help maintain regulatory certainty for operators and technology developers. By providing this expectation, stakeholders will have notice of this opportunity and can participate in the regulatory process. Additionally, specifying the timing for updates will also provide clarity on when EPA will need to receive proposed updates to studies and versions of modeling software to enable the Agency to rely on such new information in the periodic update.

Second, EPA should make clear that as part of alternative test method approval process, site-specific emission monitoring plans, or state 111(d) plans, entities can use the most recent publicly available versions of FEAST and other models, as well as recent peer reviewed studies specific to basins within that state as modeling inputs. This way, EPA can ensure the requirements for advanced technologies reflects the best information available. For example, a state, or a group of states in a single basin, may want to submit a 111(d) plan that relies on basin specific emissions data to enable the deployment of advanced technologies best suited to reduce emissions in that area provided the emission reductions are consistent with BSER. EPA should clarify that states have the flexibility to incorporate such tailored modeling, subject to EPA approving such a plan as "satisfactory" in meeting the requirements of section 111(d) and all other applicable equivalency requirements.<sup>25</sup>

Response II-5-48: It is possible that the distribution and magnitude of methane emissions from affected well sites, centralized production facilities, or compressor stations will change as these facilities come in compliance with the new and existing source rules. We also understand that many of the oil and gas basins are unique, and the distribution and leak generation rates will be variable depending on the basin. Therefore, we agree that states have flexibility in the development of their state plans to develop the most appropriate system for emission reductions so long as they are consistent with the BSER in OOOOb. Including the development of state-specific alternative technology approaches (e.g., matrix).

Finally, the Clean Air Act requires that the EPA shall, at least every 8 years, review and, if appropriate, revise such standards. As new information emission data comes available, EPA will use this information as to inform these reviews and as necessary, propose revisions to the standard.

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<sup>25</sup> Methane Roundtable, "Letter 1: Comments and Recommendations for the Alternative Survey Matrix" (hereinafter "Methane Roundtable Letter 1") (text under the heading: "Support the Comparison of Direct Benefits of Advanced Technologies") (citations omitted.)

Comment: Commenter (2399-GPA Midstream Association (GPA)) notes §60.5398b(d) contains a link to EPA’s Emission Measurement Center webpage (<https://www.epa.gov/emc/oil-and-gas-approved-alternative-test-methods>). This link does not work.

Response II-5-49: EPA has updated the website in the final rule to <https://www.epa.gov/emc/oil-and-gas-alternative-test-methods>. We intend to make this link active by the time the final rule is published.

Comment: Commenter (2399-GPA) notes the proposed § 60.5398b(c)(1)(i) states that the “sensitivity of the system must be such that it can at least measure an order of magnitude less than the action-level defined in paragraph (c)(4)(iii) of this section.” The proposed regulatory text does not contain a §60.5398b(c)(4)(iii).

Response II-5-50: EPA has corrected this reference in the final rule.

Comment: Commenter (2399-GPA) notes several sections of the proposed rule require differing accuracy, with some requiring four decimals of a degree, see, *e.g.*, proposed § 60.5398b(c)(2)(i) and others to five decimals of a degree.<sup>26</sup> Whether EPA intended to require four decimals or five decimals, it should correct those that are inconsistent.

Response II-5-51: EPA notes that in different places in the rulemaking, we may require a different degree of accuracy for coordinates, depending on what the data is used for. For the purposes of the advanced methane detection technology work practices, we have made revisions in the final rule to require at least four decimals of a degree for latitude and longitude identification.

Comment: Commenter (2247-OHEPA) observes that there are entities proposing alternate control measures to the EPA that will provide nearly equivalent level of control. The commenter believes EPA should evaluate these alternative proposals and accept these options to provide effective control measures in a cost-effective manner.

Response II-5-52: EPA acknowledges the comment and points the commenter to the alternative means of emission limitation in §60.5399b, which addresses alternative control measures (*e.g.*, fugitive emission controls). The alternative work practice standards using advanced methane detection technology in this final rulemaking is only designed to evaluate the measurement technology and detection capabilities, with the work practice requirements standardized and outlined in the final rulemaking.

Comment: Commenter (2405-Bridger) states that further clarity is needed to indicate that alternative test methods can be used in the place of both OGI and AVO inspection requirements. The commenter understands that it is the EPA’s intent to enable both the periodic screening and continuous monitoring alternative approaches to replace both OGI and AVO inspection requirements for any affected well site, compressor station, or centralized production facility. However, this provision was difficult to understand in the proposal. The commenter urges the EPA to make it clear throughout the preamble and in the regulatory text that periodic

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<sup>26</sup> 60.5398b(b)(1)(i).

screening and/or continuous monitoring alternatives may replace both OGI and AVO inspection requirements in fugitive programs.

Similarly, commenter (2405-Bridger) urges the EPA to make it clear throughout the preamble and in the regulatory text that both periodic screening and continuous monitoring alternatives can also be used instead of OGI for compliance verification of any zero emission requirements for affected facilities at well sites, centralized production facilities, and compressor stations.

Response II-5-53: EPA agrees that use of the alternative methane detection technologies replaces both OGI and AVO inspection requirements. The introductory text in §60.5398b and §60.5398c indicate that the alternative standards in those sections are an alternative to the fugitive emissions components affected facilities in §60.5397b and §60.5397c, respectively. Therefore, the work practices outlined in §60.5398b and §60.5398c replace the entire work practice required in §60.5397b and §60.5397c, which includes both AVO and OGI (or EPA Method 21) inspections. This applies for both the periodic screening matrix alternative work practice and the continuous monitoring work practice.

## **5.8 Alternative Periodic Screening**

### ***5.8.1 Matrix Approach***

Comment: Commenters (2249-National Association of Clean Air Agencies (NACAA)), 2258-Marcellus Shale Coalition (MSC), 2326-AXPC, 2403-The Petroleum Alliance of Oklahoma (PAO), 2458-MiQ) are generally supportive of EPA's matrix approach. Certain commenters have additionally suggested revisions that they believe are needed before operators can implement, as described further below.

Commenter (2249-NACAA) generally supports EPA's proposed matrix approach for approving methane detection technologies, although advocate that EPA's engagement with affected agencies to explore nuance and specifics that vary by location, rather than depending entirely on detection limits and a basis for selection.

Commenter (2458-MiQ) supports EPA's developed matrix for monitoring frequency of advanced technologies, based on their respective minimum detection threshold included in this matrix framework.

Commenter (2403-PAO) supports the use of alternative monitoring technologies that allows operators flexibility in using technologies tailored for their site-specific conditions. However, EPA's proposed matrix is too prescriptive focusing on frequency and sensitivity - the less sensitivity a technology, the more frequently it should be used and visa vise while requiring the use of overlapping technologies. However, this matrix is more stringent than the use of OGI. The commenter is concerned that the Proposed Rule will stifle new technology development and limit flexibility. There are multiple ways to achieve monitoring and EPA should not limit or prescribe a technology when a variety of technologies would suffice to find and fix leaks. The commenter requests EPA reconsider and revise its matrix that encourages the development of

new technologies that can be used interchangeably by operators (based on site specific conditions) to find and fix leaks quickly and economically.

Response II-5-54: EPA acknowledges the commenters points and argues the matrix approach is technology agnostic and is designed to accommodate the continued advancement of this technology. The matrix is not more stringent than the use of OGI as the tiers are based on the equivalent emission reduction you would expect of the BSER program as detailed in our supplemental TSD FEAST memos in the docket of this rule.

EPA does agree with the commenters that the matrix approach could be applied to multiple technologies and the final rule now makes that allowance explicit.

Comment: Commenter (2258-MSC) indicates that the alternative monitoring matrix is not adoptable by operators in its current form. The following suggestions would assist with developing requirements that would allow operators to utilize alternative technologies now and provide the ability to adjust frequencies and use of technology as the technology improves and costs reduce.

- Develop a technology agnostic matrix that allows a combination of techniques (*e.g.*, AVO, OGI, flyovers, continuous monitoring) at varying frequency. For example, an operator could deploy both flyovers, continuous monitoring, and OGI, but at reduced individual frequencies as proposed in the rule.
- It is important to not under-represent the effectiveness of OGI or under-represent the effectiveness of alternative technology with the modeling inputs. The commenter requests EPA to work closely with stakeholders such as API or others who have spent considerable time determining the appropriate inputs to the model that establishes a baseline performance for OGI and equivalency for alternative monitoring methods.

Response II-5-55: EPA acknowledges the commenter's feedback and disagrees with the assertion the alternative periodic monitoring through the matrix framework is not adoptable. As EPA is finalizing the matrix framework with some revisions explained in Section X.B and XI.B of the preamble of the final rule.

Comment: Commenter (2387-Energy Institute, Colorado State University (CSU)) believes AVO performance is likely overestimated in EPA modeling. While it was unknown if operators had implemented some type of enhanced AVO protocols<sup>27</sup>, essentially none of these emitters was discovered by AVO methods. These data suggest a near-zero probability of AVO detection for a minimum of 4.8 [0.91 to 12] days for LongPath data and 86 [2.5 to  $0.22 \times 103$ ] days for Kuva data. These data suggest that the AVO efficacy used in EPA's models may overstate the performance of AVO methods. The commenter encourages EPA to review, study, or reduce reliance on AVO methods in calculating the proposed matrix parameters.

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<sup>27</sup> The authors know of no defined protocol which would separate normal operational practice from an enhanced AVO survey.

Response II-5-56: EPA did not include the hybrid OGI/AVO approach when modeling the matrix equivalency. For the periodic screening matrix, we assumed essentially no AVO triggered repairs.

Comment: Commenter (2419-Xplorobot) requests that the matrices for alternative screening be amended to include “Annual OGI or equivalent hand-held component-level inspection” in place of “Annual OGI” to provide for the opportunity to deploy novel hand-held component-level solutions in combination with aerial surveys or continuous sensors for cost-effective methane monitoring of oil and gas operations.

Response II-5-57: EPA acknowledges the commenters request; however, EPA has chosen to maintain OGI requirements in the final rule as proposed. This rule also is forward leaning on potential alternatives methane monitoring solutions including multiple alternative pathways for their use and encourage the commenter to explore the most appropriate pathway for their methane solution.

Comment: Commenter (1686/2345-GHGSat, Inc. (GHGSat)) believes the minimum detection levels and monitoring frequencies currently specified in the proposed matrix are insufficiently differentiated between the five tiers with respect to detection levels. The commenter is concerned that the matrix definition will unintentionally hamper the utilization of remote sensing approaches that have the capability of more frequent surveys with higher minimum detection limits. Since the proposed minimum detection thresholds of the lower tiers are within the same order of magnitude, it will be extremely difficult for existing technologies to meet these requirements because there are other factors such as wind speed, light conditions, and atmospheric considerations that will produce errors resulting in an effective overlap between the tiers.

Commenter (1686/2345-GHGSat) recommends a revision to each matrix such that the first three tiers with the lowest detection limits become a single tier of 5 kg/hr that requires quarterly monitoring plus an annual OGI survey. The 10 kg/hr and 30 kg/hr can remain as proposed. The commenter would then recommend the addition of two new tiers, one with a minimum detection threshold of 60 kg/hr in which biweekly surveys plus an annual OGI survey need to be performed, and a final tier with a detection threshold of  $\leq 100$  kg/hr that requires performing weekly surveys plus an annual OGI survey. The commenter believes that adding these two tiers establishes a bridge between the current proposed detection thresholds and the proposed super emitter program. The commenter believes that with this modification to the survey matrix, the EPA will minimize controversy regarding the qualification and approval of technologies in the 1 to 4 kg/hr. The commenter believes that controversy could exist with companies trying to select an alternative monitoring technology due to the narrowness of the tiers and the differences in frequencies amongst them. Also, technology providers understand that during the assessment and creation of detection curves, multiple environmental conditions could have an impact in detecting emissions. For that reason, a typical measure of MDL is associated with a 50% POD, as it provides additional flexibility to account for varying environmental conditions.

Commenter (1686/2345-GHGSat) notes that EPA relied on FEAST modeling to derive the different tiers listed in the matrices. One of the conclusions was that technologies with minimum

detection threshold above 30 kg/hr could not be deemed equivalent to the proposed fugitive emissions monitoring and repair program at any screening frequency, even when coupled with an annual OGI ground-based survey. The commenter disagrees with that conclusion, and believes that, even though modeling scenarios help in the understanding of an outcome based on certain variables and input parameters, the empirical knowledge reflects a different outcome. The commenter's satellites and aircraft continue to detect emissions from different oil and gas infrastructure across the United States and around the world. The same empirical knowledge applies to the breakdown of the smallest tiers in the matrices. The emissions distributions used in the model represent the conditions at the time of the study. Drawing conclusions of different tiers within the same order of magnitude skew the actual conditions on the field.

Commenter (1686/2345-GHGSat) also believes the EPA should provide a mechanism that accounts for the combination of technologies that, when working in tandem, can achieve the methane reduction equivalent to a single solution. The commenter understands that the EPA would expect other available modeling simulations to be included in the different analyses. The commenter has recently performed a novel study following a tiered topdown approach using satellite and aircraft to monitor oil and gas facilities in the Permian basin.<sup>28</sup> An abstract, highlights, and link to this paper can be found in Appendix C.

Commenter (1686/2345-GHGSat) indicates that there are different technologies capable of detecting and quantifying emissions operating with different techniques and at a different level. These technologies, and the combination of them working in tandem in a tiered approach, can provide greater reductions at a lower cost, when compared to OGI alone.<sup>29</sup>

Response II-5-58: EPA acknowledges the comment's input. However, we are finalizing the matrix approach as proposed, with the exception of the removal of the highest tier (30 kg/hr) due to the concern over equivalency with the BSER being overly reliant on the annual OGI backstop.

Comment: Commenters (2340-Honeywell International Inc. (Honeywell), 2363-CEMC, 2402-DGCC, 2448-Project Canary) believe that continuous monitoring technologies should qualify for use as periodic screening systems, and the rule should allow for greater flexibility within the periodic screening matrices. The regulations should provide maximum flexibility to allow for the use of any type of technology—including a networked system of various monitoring technologies capable of providing effective emissions monitoring under either the periodic screening or continuous monitoring alternative LDAR programs. In particular, the final rule should specify that (a) continuous monitoring systems may also qualify as periodic screening systems provided, they meet the prescribed criteria, and (b) FEAST modeling can be used to determine a greater variety of detection thresholds and screening frequencies than those presented in the periodic screening matrices.

Commenter (2340-Honeywell) believes continuous monitoring systems should also qualify as periodic screening systems if they meet the detection thresholds and probability of detection specified in the survey matrices. In addition to measuring emissions on a continuous basis, such systems, including Honeywell's Rebellion and Signal Scout technologies, can detect emissions

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<sup>28</sup> Esparza, et al., 2023 (under peer-review).

<sup>29</sup> (Esparza, et al., 2021); (Esparza, et al., 2021); (Esparza, et al., 2022); (Esparza, et al., 2023 (under peer-review)).

on a periodic screening basis at the thresholds provided in the survey matrices. The commenter provides substantial information in their comment letter describing their Rebellion technology (Rebellion Gas Cloud Imaging (GCI) system) and their Signal Scout technology (Honeywell Emission Management Solution, comprising of Honeywell Versatilis™ Signal Scout™ detectors, Gateway and Anemometer). The commenter believes that both these continuous monitoring solutions are capable of meeting the detection thresholds set out in the periodic screening matrices while providing much more frequent monitoring.

Commenters (2298-Pioneer, 2363-CEMC, 2402-DGCC, 2448-Project Canary) note that EPA recognizes that continuous monitoring technologies “could be valuable tools in quickly detecting large emissions events, as well as identifying when emissions at the site begin to rise”. However, EPA proposes to regulate non-visual continuous monitors separately by requiring operators to screen more frequently and at lower detection levels than required in the periodic screening matrix, and it is unclear how camera based continuous monitors can be deployed under the proposal.

Commenters (2298-Pioneer, 2363-CEMC, 2402-DGCC, 2448-Project Canary) assert that EPA’s proposed approach would discourage the use of continuous emission monitors for compliance with the rule. EPA proposes greater response requirements for operators using the continuous monitor approach by requiring operators to initiate an investigative analysis each time there is an exceedance of relatively small site-wide emission rates compared with the survey matrix’s relatively large point-source emission rates. The approach also does not recognize that continuous emission monitors with valid quantification and full-site coverage can directly measure both baseline and fugitive emissions. Temporal information can easily identify when deviations from baseline emissions occur.

To ensure that the rule is technology neutral, commenters (2298-Pioneer, 2363-CEMC, 2402-DGCC, 2448-Project Canary) urge EPA not to include greater response requirements or more stringent emissions thresholds for some technologies. If a technology can detect more frequently than required in the periodic screening matrix, that should not create additional (more frequent response requirements) than would apply to an owner or operator deploying OGI or other periodic screening technologies. While a company may use a technology that collects emissions information more frequently than monthly, the obligation should be to demonstrate compliance with fugitive emission requirements no more frequently than the frequency required by the matrix based on the application detection threshold for the technology.

Commenters (2298-Pioneer, 2363-CEMC, 2402-DGCC, 2448-Project Canary) therefore, urge EPA to allow owners and operators to use both image-based and nonvisual continuous monitoring technologies under the periodic screening matrix provided the technologies can meet the screening matrix’s frequency and detection thresholds or equivalent thresholds based on concentration levels.

Response II-5-59: EPA never intended to limit continuous monitoring technologies (visual or non-visual) from the periodic screening approach in the December 2022 supplemental proposal. In the final rule we have clarified the record that continuous monitoring technology may be applied to the periodic screening framework.

Comment: Commenter (2333-LongPath) recommends that EPA:

- Consider an organizational structure of technology classes for ease of characterizing the different response requirements in the periodic screening matrix that is consistent with the following:

|                              | <b>Visual (plume-level)</b>                                                                                                                                                                                                                                                                                                                                                | <b>Non-Visual (site-wide or source-level)</b>                                                                                                                                                                                                                                                                                                                                               |
|------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Periodic Screening</b>    | <ul style="list-style-type: none"> <li>Detection and/or quantification of discrete emission sources; cannot directly quantify site-wide emissions.</li> <li>Discrete in time; cannot characterize intermittency.</li> <li>Examples include aircraft, drone and satellite platforms.</li> <li>A subset of these solutions may produce valid mass emission rates.</li> </ul> | <ul style="list-style-type: none"> <li>Detection and/or quantification of total sitewide emissions; may also localize emission sources.</li> <li>Discrete in time; cannot characterize intermittency.</li> <li>Examples include mass balance from drone, aircraft and mobile platforms, and OTM-33a.</li> <li>A subset of these solutions may produce valid mass emission rates.</li> </ul> |
| <b>Continuous Monitoring</b> | <ul style="list-style-type: none"> <li>Detection and/or quantification of discrete emission sources; cannot directly quantify site-wide emissions</li> <li>Continuous in time; can be used to characterize intermittency</li> <li>Examples include fixed camera-based platforms</li> <li>A subset of these solutions may produce valid mass emission rates</li> </ul>      | <ul style="list-style-type: none"> <li>Detection and/or quantification of total sitewide emissions; may also localize emission sources</li> <li>Continuous in time; can be used to characterize intermittency</li> <li>Examples include arrays of point sensors, and line sensors</li> <li>A subset of these solutions may produce valid mass emission rates</li> </ul>                     |

- Create a clear option for the use of the above technologies in the periodic screening matrix. Commenter (2333-LongPath) provides the following suggestions for how to avoid inadvertently disincentivizing any technology classes:
  - Perform equivalency modeling for all solutions directly in the FEAST model, rather than developing a separate set of standards based on FEAST model outputs from other methods.
  - If a technology can detect more frequently than required in the periodic screening matrix, there should not be additional (more frequent) response requirements than would apply to an owner or operator deploying OGI or other periodic screening technologies. That is, detections made outside the defined periodic screening frequency intervals should not require immediate follow-up, just as additional aircraft surveys in between periodic screening frequency intervals do not.
  - Specifically for non-visual site-wide monitors that produce a valid mass emissions rate:
- Fugitive emissions and action levels should be defined as “above baseline emissions”, because these monitors measure permitted (“allowable”) emissions in addition to point source (fugitive) emissions.
- Response requirements should be based on Action Levels (plus baseline) rather than Detection Levels.



- Adjust the follow-up OGI requirements to recognize that temporal and spatial information from advanced technologies may be able to identify the root cause of the emission without OGI (in the case of quantitative, temporal information) or more effectively direct follow up OGI to a smaller area (in the case of spatial information that shows the location of the leak). If a technology is capable of determining a leak's level of intermittency (most continuous monitors), then follow-up OGI can be omitted for intermittent emissions (since spot-check and survey methods rarely identify intermittent leaks.<sup>30</sup>

Response II-5-60: EPA acknowledges the commenters input, when a more continuous system is used in a periodic screening application, when a leak is detected (*e.g.*, emission event above 10kg/hr) during a screening period, however defined in your Alternative Test Method for Methane Detection Technology, you are required to follow-up regardless of intermittency unless the technology used has component level resolution and is sufficiently sensitive to confirm a leak isn't present.

Additionally, leak definitions in the periodic screening program are independent of background concentration of a facility. If background is a consideration, this must be integrated into the methane detection alternative test method with supporting evidence as to why this is required.

Comment: Commenter (2333-LongPath) urges EPA to clarify the spatial coverage requirements for all monitors in the periodic screening matrix. Some continuous monitoring solutions may permanently miss certain equipment (*e.g.*, visual solutions may have "blind spots" due to line-of-sight blockage) or systematically under-sample certain equipment for long periods of time (*e.g.*, ground-based sensors may not consistently detect plumes from tall equipment). Some aerial screening solutions may miss covered equipment. It is important for EPA to set a standard for which equipment must be screened and when. The commenter presumes that the same equipment that is required to be scanned by OGI should also be required to be scanned by alternative technologies, but requests that EPA more clearly define this requirement.

Commenter (2333-LongPath) argues a technology must demonstrate how often all required equipment is scanned. Therefore, assuming that the EPA's definition would be, for example, 100% of fugitive equipment sources, then this parameter would be set to 100% coverage of all equipment over some period of monitoring. The methods (*e.g.*, averaging time and scanning time) required for achieving 100% site coverage will be highly technology-specific, and should therefore be included in each solution's alternative test method application.

Response II-5-61: EPA appreciates the commenter's input. EPA's assumption is that technology used for methane detection would include 100% coverage of a site which and the ability to measure all components at a site would be evaluated as part of a technology providers applications for Alternative Test Method for Methane Detection Technology.

Comment: Commenter (2333-LongPath) states for continuous monitors used in the periodic screening matrix, the time-to-detect should be the same as all other technologies in the same

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<sup>30</sup> See joint comment submitted by Dan Zimmerle, Stefan Bokaemper and Caroline Alden (EPA-HQ-OAR-2021-0317-2387).

matrix frequency bin. To ensure that the rule is technology neutral, the commenter urges EPA not to include greater response requirements or more stringent emissions thresholds for some technologies. If a technology can detect more frequently than required in the periodic screening matrix, that should not create additional (more frequent response requirements) than would apply to an owner or operator deploying OGI or other periodic screening technologies. While a company may use a technology that collects emissions information more frequently than monthly, the obligation should be to demonstrate compliance with fugitive emission requirements no more frequently than the frequency required by the matrix based on the application detection threshold for the technology.

Response II-5-62: For those technologies that are continuous in nature, when used in periodic screening, a screening survey should be at least 2X the time-to-detect for any given technology. The number of screening events is dependent on the tier of the matrix framework most appropriate for the technology. There is not a reason that a technology couldn't continue to operate outside of a survey period.

Comment: Commenter (2446-IPAA) notes there are many approaches to developing matrices to frame a series of fugitive emissions requirements that reflect the emissions profiles of oil and natural gas production facilities. The commenter believes that the most straightforward approach would be to use production rates with some adjustments for specific onsite equipment. This approach would utilize information from DOE Study. However, EPA has an inordinately intense fascination with the use of component counts at facilities. This reliance on a system that uses component counts portends a potential complicated conflict implementing the EG because states have not used component counts in their current regulatory programs and could resist EPA's actions to force the approach on them.

Response II-5-63: EPA acknowledges the commenter's input.

Comment: Commenter (2192-Blue Sky Measurements, Inc. (BSM)) agrees with the proposed matrix. The commenter notes that NIRview can be considered a high frequency periodic screening technology capable of measuring multiple times per day with a detection threshold <4 kg/hr. NIRview is a passive device dependent on sunlight. NIRview units will operate on cloudy days with filtered sunlight but performance is diminished on heavy overcast days where the condition persists the entire day. Also, like all other sensing technologies currently in operation, NIRview performance is a function of environmental conditions such as wind speed and rain but as a fixed position monitor, multiple measurements per week will be the norm.

Response II-5-64: EPA acknowledges the commenter's input, and we agree environmental conditions are important factors to consider when measuring methane at an oil and gas facility.

### **5.8.2 Action Levels**

Comment: Commenter (2333-LongPath) argues for site-wide, quantitative continuous monitors, Action Levels should be defined as "above baseline emissions." Non-visual continuous monitors (the lower right-hand box in the table above) with valid mass emission rates measure total, site-wide emissions. This means these monitors measure the sum of permitted process emissions and

fugitive emissions. By definition, the emissions mitigated by OGI in the FEAST model (those used to calculate the continuous monitoring action levels) are exclusively fugitive emissions; the FEAST model does not mitigate permitted emissions.

Commenter (2333-LongPath) states examples of permitted emissions that contribute to a persistent but variable, non-zero baseline emission rate are compressor exhaust (“slip”), incomplete combustion (*e.g.*, 5% loss from flares), and pneumatic devices. The CEMC comment provides an example in which a site with 8 pneumatic valves (standard on many sites) would easily exceed the lowest frequency periodic survey rate (and the continuous monitoring LongTerm Action Level). Another example would be a single 2-stroke lean-burn engine for a permitted compressor, which would exceed the lowest frequency periodic survey rate (and the Long-Term Action Level) by 3 times. Therefore, solutions that measure site-wide emissions should not be required to act on permitted emissions.

To address this, commenter (2333-LongPath) suggests that emissions from allowable activities not be included in the total rate of emissions that require action for site-wide emissions monitors. The commenter recognizes that EPA may have sought to achieve parity with VOC reductions, however there is no such requirement for non-continuous monitors. Therefore, it would not be technology-neutral to create this added burden for continuous monitors. In short, technologies capable of providing more comprehensive measurement of total emissions should not be inadvertently disincentivized for use in the periodic screening matrix or in the continuous monitoring provisions by requiring action on permitted emissions.

Commenter (2333-LongPath) states to ensure owners and operators respond to leaks and process failures, and to ensure that site-wide continuous monitors are not unfairly burdened in the rule, EPA will need to define Action Levels as above the measured baseline allowable emissions. Because continuous emission monitors with valid quantification and full-site coverage can directly measure both baseline and fugitive emissions, it should be allowable for site-wide continuous monitors to quantify baseline emissions through time and identify emissions that exceed the sum of the baseline emissions plus the action levels defined in the matrix.

Response II-5-65: Leak definitions in the periodic screening program are independent of background concentration of a facility. If background is a consideration, this must be integrated into the methane detection alternative test method with supporting evidence as to why this is required.

Comment: Commenter (2405-Bridger) states quantification is crucial for the periodic screening approach because mass emission rates are needed to generate emission rate distributions. These distributions are a powerful tool for auditing the detection sensitivity of alternative test methods during field deployment. In the Technical Support Document for the Proposed rule, an emission rate distribution is used to model super emitter events. By inspecting the distribution, researchers concluded that there were false negative detections between 5 and 50 kg hr<sup>-1</sup> based on the low number of detections in this emission rate region.<sup>31</sup> Recently, the commenter released a preprint

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<sup>31</sup> US EPA. Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). (2022).

describing a rigorous statistical analysis of this emission rate distribution which revealed the detection sensitivity that was actually realized.<sup>32</sup> In other comments, the commenter urges the EPA to audit emission rate distributions to assure stakeholders that alternative test methods achieve stated detection sensitivity. Requiring periodic screening technologies to demonstrate quantification capabilities also provides consistency with requirements for continuous monitoring technologies.

Commenter (2405-Bridger) states that Advancing Development of Emissions Detection (ADED) protocols referenced by the commenter provide standard protocols for evaluating the quantification performance of periodic screening methane sensing technologies and continuous monitoring systems. The EPA should require alternative test method applicants to demonstrate quantification through third party testing using these protocols to provide consistency and transparency.

Response II-5-66: EPA recognizes the commenter's input; For discussions on EPA's modeling and the methane detection alternative test methods, please see sections X.B.1, X.B.3, XI.B.1, and XI.B.3 of the preamble to the final rule.

### ***5.8.3 Screening Frequency/Minimum Detection Threshold***

Comment: Commenter (2428-API) expresses that the proposed periodic screening matrices do not incentivize the use of the alternative technology.

The commenter states while API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of  $\leq 1$  kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, the commenter believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of  $\leq 10$  kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly.

Commenter (2428-API) states these matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (*i.e.*, minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (*i.e.*, monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency

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<sup>32</sup> Kunkel, M. W. et al. Extension of Methane Emission Rate Distribution for Permian Basin Production Infrastructure by Aerial LiDAR. (2022).

and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

Commenter (2326-AXPC) notes that it also supports the API's more extensive comments on this issue. The commenter believes EPA's proposed matrix is a step in the right direction. However, EPA's alternative leak detection program requires critical revisions before operators could utilize it as a viable alternative to traditional inspection methods.

Response II-5-67: EPA recognizes the commenter's input; For discussions on EPA's matrix framework, please see sections X.B.1 and XI.B.1 of the preamble to the final rule.

Comment: Commenter (2406-EEMDL) states annual OGI survey as part of site-wide screening strategy is more critical when the detection threshold of the screening technology is 10 kg/hr or higher. Thus, all site-wide screening surveys using technologies with detection thresholds >10 kg/hr require annual OGI surveys to mitigate below detection threshold emissions and achieve equivalence.

Response II-5-68: EPA acknowledges the commenter's input; this statement is consistent with EPA's modeling.

Comment: Commenter (2406-EEMDL) states the annual OGI survey associated with equivalence conditions for site-wide screening is a significant contributor to emissions reductions when paired with screening technologies with high detection thresholds. Figure 1 shows the site-level emissions in metric tons per year associated with monthly site-wide screening, with and without annual OGI survey for a large emitter duration scenario of 45 days. The difference between site-level emissions with and without annual OGI increases as the detection threshold of the site-level technology increase. With a technology with detection threshold 4 kg/h, site-level emissions with and without annual OGI are similar (given model uncertainties). However, using a technology with detection threshold 30 kg/h, the site-level emissions with annual OGI is significantly lower compared to that without annual OGI. This is because the site-level screening technologies does not detect below detection threshold emissions, and with increasing detection threshold, more of the normal fugitive emissions are not detected by the screening technology. Furthermore, as the duration of large emitter events decrease, the contribution of normal fugitive emissions to total emissions increases, thereby increasing the importance of annual OGI surveys.

Figure 1. Site-level emissions (metric tonnes per year) with (blue) and without (orange) annual OGI using three site-wide screening technologies for a large emitter duration of 45 days.

Commenter (2406-EEMDL) states Table 2 compares site-level emissions in metric tonnes per year with and without annual OGI for two site-wide technologies with detection thresholds 4 kg/h, 10 kg/h, and 30 kg/h, with that of quarterly OGI for large emitter duration of 90 days. For the site-wide screening with detection threshold 4 kg/h, the site-level emissions from monthly site-wide screening with and without annual OGI (7.5 mtpy vs. 5 mtpy) are not statistically significant, implying that the annual OGI does not significantly increase emissions reductions.

Thus, in this model, monthly site-wide screening with a 4 kg/h detection threshold technology will be equivalent to quarterly OGI (although the EPA methane rule specifies bi-monthly site-wide screening with annual OGI as the equivalence condition for quarterly OGI surveys, the underlying EPA modeling identifies two equivalence points: bi-monthly site-wide screening with annual OGI or monthly site-wide screening without annual OGI). By contrast, the site-level emissions when using a screening technology with a detection threshold of 30 kg/h demonstrate the impact of annual OGI survey, along with monthly site-side survey. The site-level emissions under monthly survey with and without annual OGI is 7.4 tpy and 38.4 tpy, respectively. The equivalence condition with quarterly OGI is achieved only when monthly site-wide screening is paired with an annual OGI survey, similar to the matrix provided in the supplemental rule. This is observed across different assumptions about duration of large emitters modeled in this study.

Table 2: Site-level emissions (metric tonnes per year) for three site-wide screening technologies with and without annual OGI with a 90-day large emitter duration.

Commenter (2406-EEMDL) states this result can be explained by observing emissions across different categories of emitters and demonstrates two competing effects. As the duration of large emitters decrease, monthly site-wide surveys are more effective in detecting large emitters compared to quarterly OGI surveys. However, at the same time, the contribution of large emitters to total emissions decreases as the duration of the large emitters decrease. This increases the importance of reducing normal emitters. These two features counterbalance each other, thus keeping the equivalence condition similar to those for persistent large emitters as shown in the supplemental proposal.

Response II-5-69: EPA acknowledges the commenter's input.

Comment: Commenter (2196-Private Citizen) states that the EPA is proposing a matrix of new periodic BSER options to facilitate the acceptance of what is considered advanced measurement techniques (AMT): Below is BESR option for quarterly frequency and number 1 below is included for reference:

- Human operated or Handheld OGI (Non-AMT BSER).
  - Can depict as low as 1 g/hr methane in calm conditions.
  - Can depict 10 g/hr in windy conditions where a technician would be out surveying
- Periodic Screening (Flyovers & Satellites)
  - Allowed  $\leq 1000$  g/hr or  $\leq 1$  kg/hr & Annual Human OGI required annually

Commenter (2196-Private Citizen) states these two BSER options are not equivalent even when you require the "annual OGI". The proposed non-AMT BSER (Human OGI) is 2 to 3 orders of magnitude lower when detecting leaks. LDAR is a mature process, though more recently applied to upstream and midstream oil & gas. Two factors impact reduction in emissions from equipment leaks. These are inspection frequency and leak threshold. The suggested periodic quarterly AMT leak frequency is the same as the non-ATM BSER option (except you require an annual Human OGI inspection). Again, the leak threshold allowed by periodic BSER (AMT) in Table 1 (Row 1) is 2 to 3 orders of magnitude higher than the Non-ATM BSER (Human OGI) that it would be

replacing. [Table 1 shows the commenter's recommended changes to the (1) Minimum Screening Frequency and (2) Minimum Detection Threshold of Screening Technology matrix approach.]

Commenter (2196-Private Citizen) continues, inspecting at the same frequency at conceptual leak definition that is 2 to 3 orders of magnitude higher than the other option it is conceptually equivalent to. The scenario is counter to EPA's LDAR reduction's philosophy since the beginning in the late 1980's. That is, if you want equipment leak reductions you either 1) inspect more frequently, or 2) the frequency remains the same and you drop your leak threshold. EPA has historically established this with a Monte Carlo analysis. In the alternative proposed for periodic AMT, the frequency remains the same even though the leak threshold increases by 2 or 3 orders of magnitude.

Commenter (2196-Private Citizen) recommends that the EPA has attempted too many stratifications as it tries to facilitate the emergence of new technologies. It is recommended that you only have 2 stratifications for the periodic AMT. The highest being one order of magnitude lower than the proposed super emitter program which is 100 kg/hr (*i.e.*, 10 kg/hr) and the lowest one being 1 order of magnitude lower than the higher one (1kg/hr or 2 kg/hr, I would say 2 kg/hr would be acceptable. 2 kg/hr is essentially close to an order of magnitude and ultimately would be more achievable by a larger number of pending AMT's. This approach simplifies and applies an overall system approach to leveraging the use of Alternative Monitoring Technologies to reduce emissions.

- 100 kg/hr – detection level proposed for Super-emitter program
- 10 kg/hr – Detection level for highest AMT allowed. (1 order of magnitude lower than Super-emitter) ... (More than Likely Satellite Technology)
- 2 kg/hr – Detection level for lowest AMT allowed (1 order of magnitude lower than highest AMT) .... (Most likely, flyover type technology)
- 0.01 kg/hr – Conservative detection level for Human-based OGI

Response II-5-70: EPA acknowledges the commenter's input; for clarification purposes the matrix framework is not BSER and instead is a determination of equivalent methane emission reduction based on equivalency modeling as described in Section X.B.1 and XI.B.1 in the preamble of the rule.

Comment: In the periodic screening matrix, commenter (2333-LongPath) strongly recommends that EPA require monitoring and reporting on the same cadence for each technology class. Additionally, voluntary OGI screening between the required frequency intervals can enable operators to mitigate additional emissions, but EPA does not require operators to take regulatory action based on those efforts. So should operators be allowed to collect and use continuous monitoring data between the required frequency intervals for voluntary, additional emissions mitigation, without an EPA requirement for response. The commenter therefore suggests that EPA allow for the use of non-visual continuous monitors to provide coverage of all regulated equipment with the same frequency as is prescribed by the periodic screening matrix, but to exclude information from outside that time interval from fugitive regulatory action (closed vent monitoring may be considered separately). It is far better to allow operators to leave continuous monitor data "on" in between periodic screenings, and to use that data for additional voluntary

mitigation, than it would be to inadvertently incentivize operators to turn continuous monitor data “off” between periodic screenings so as to avoid response requirements.

Commenter (2333-LongPath) states if a technology can detect more frequently than required in the periodic screening matrix, that should not create additional (more frequent) response requirements than would apply to an owner or operator deploying OGI or other periodic screening technologies. While a company may use a technology that collects emissions information more frequently than monthly, the obligation should be to demonstrate compliance with fugitive emission requirements no more frequently than once a month—or the frequency required by the matrix based on the application detection threshold for the technology. Just as an operator should be allowed to perform more frequent OGI or aircraft surveys than required by the matrix without being subject specific response requirements in case of a detection, operators should also be able to use continuous monitoring information in the periods between the required survey frequency without added response burdens. In short, operators should be allowed to perform additional, more comprehensive emissions reductions voluntarily without incurring additional regulatory compliance burdens. Just as operators will be given leeway in deciding when to perform the required periodic screening with OGI or a survey technology, so long as the frequency requirements are met, operators should be given the same leeway in determining when to perform required periodic screening with continuous technologies, so long as those same frequency requirements are met.

Commenter (2333-LongPath) notes that the term “frequency” is typically poorly defined because of a hidden but important contributing dimension: spatial coverage. While a continuous monitor may deliver a mass emission rate every minute, the key question is how much of the site was “covered”, “seen”, or “represented” with that measurement. Put another way, what is the upwind fetch of each measurement, and how much time would it take to “see” all regulated equipment on the site is critical. Models show that it can take hours to days or even weeks, depending on sensor geometry and location, to achieve full coverage of all emission sources on a site. Similarly, while a periodic screening aircraft survey might cover the entirety of the site, there may be equipment hidden from line-of-sight. To avoid confusion, frequency specifications must always therefore be accompanied by clear definition of “how much of the site” and “how often for all equipment”.

Response II-5-71: EPA has revised the final rule to allow for technology that operates continuously to be used for either periodic screening or continuous applications dependent on the choice of an owner or operators and whether a technology can meet the applicable requirements. When used for periodic screening, the screening period will be determined according to what is defined in a technology’s alternative test method for methane detection technology. An owner or operator is not required to operate the systems outside their screening frequency, however continued used could be valuable these systems provide valuable information.

Comment: Commenter (2405-Bridger) states requirements for continuous monitoring and periodic screening require greater consistency. Because continuous monitoring is higher frequency emissions monitoring than monthly screening, the proposed 30 kg/hr periodic screening tier provides a less stringent work practice for emissions reduction. Because different options for emissions monitoring work practices should achieve equivalent levels of emissions



reduction, the commenter urges the EPA to remove the 30 kg/hr detection tier. To the commenter's understanding, all commercial airborne remote sensing methane detection technologies are capable of achieving 10 kg/hr (90% probability of detection) including sensing technologies deployed from a high-altitude aerial platform.<sup>33</sup> Removing the poorest sensitivity (30 kg/hr, monthly scans) option would therefore not exclude any current commercial airborne technology class.

Commenter (2405-Bridger) adds it must also be noted that the efficacy of the 30 kg/hr detection tier will be reduced in less heavy-tailed basins than the Permian. The EPA evaluated detection sensitivity tier equivalence using a large emitter emission rate distribution measured in the Permian Basin where large emissions represent an outsized share of cumulative emissions. However, when comparing a basin with a less heavy-tailed emission rate distribution to a basin with a more heavy-tailed distribution like the Permian (Figure 2), it is clear that emissions above 30 kg/hr represent a much smaller percentage of emissions and significantly fewer emissions reductions will be achieved using this detection sensitivity tier. This phenomenon is accentuated at higher detection tiers such as 30 kg hr<sup>-1</sup> compared to lower detection tiers.

[Figure 2. Cumulative emission rate distributions measured by GML in two different North American production basins. The percent of total measured emissions that had rates above 30 kg hr<sup>-1</sup> is significantly greater in the basin with a more heavy-tailed emission rate distribution compared to the basin with a less heavy-tailed distribution. The difference in percent measured emissions above a given emission rate is smaller for lower emission rates.]

Response II-5-72: EPA acknowledges the commenter's input. For discussions on EPA's matrix framework, please see sections X.B.1 and XI.B.1 of the preamble to the final rule.

Comment: Commenter (1686/2345-GHGSat) notes that its operational and growing satellite constellation and fleet of aircraft are available now to satisfy the proposed requirements under section 111 of the CAA. To achieve the greatest possible reductions in methane while remaining achievable and cost effective, the EPA must embrace a broader range of technological innovations for regulatory screening.

Commenter (1686/2345-GHGSat) believes that an aspect of the supplemental proposal that needs reconsideration is the minimum detection levels and monitoring frequencies currently specified in the proposed matrix. The commenter is concerned that the matrix as currently defined will unintentionally hamper the utilization of technological innovations that have the capability to enable the greatest possible reductions in methane by having more frequent surveys with higher minimum detection limits. The commenter recommends the EPA consider revising its proposed matrix approach with respect to detection levels with a reorganization of the detection thresholds and monitoring frequencies that would be more operationally effective and also establish a bridge between detection threshold and the proposed super-emitter program while providing a mechanism that accounts for the combination of innovative technologies that,

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<sup>33</sup> Digital Roughnecks. How to Pick the Right Technology to Future-Proof Your EPA OOOO b/c LDAR Program. YouTube <https://youtu.be/m4y1Rtil2bE> (2022).

when working in tandem, can achieve the methane reductions mandated under Section 111 of the CAA.

Commenter (1686/2345-GHGSat) recommends a revision to the matrix such that the first three tiers with the lowest detection limits become a single tier of 5 kg/hr that requires quarterly monitoring plus an annual OGI survey. The 10 kg/hr and 30 kg/hr can remain as proposed. The commenter would then recommend the addition of two new tiers, one with a minimum detection threshold of 60 kg/hr in which biweekly surveys plus an annual OGI survey need to be performed, and a final tier with a detection threshold of  $\leq 100$  kg/hr that requires performing weekly surveys plus an annual OGI survey.

Response II-5-73: EPA acknowledges the commenter's input. For discussions on EPA's matrix framework, please see sections X.B.1 and XI.B.1 of the preamble to the final rule.

Comment: Commenter (2316-ABB) believes that the EPA should comprehensively study commercially available methane leak detection technologies and products to understand the available features in the state-of-the-art offerings (which provide improved performance and reliability). This will enable the EPA to consider which minimum detection thresholds are feasible, not cost prohibitive and ultimately help enable the effective reduction of methane leaks.

Response II-5-74: EPA acknowledges the commenter's input. EPA is aware how quickly these methane detection measurement systems are being developed and improved. To complete a comprehensive study of all measurement solutions could take years and by the end of the study, our findings could be dated. The approach in this rule is technology agnostic and provides performance targets for these technologies.

Comment: Commenter (2325-Aclima) believes the detection thresholds in the matrix Table 20 and Table 21 are fair detection thresholds that are achievable with today's technology. However, even lower detection thresholds are imminently achievable using sensor-based technology that can be installed permanently on each well and monitor continuously for less cost than periodic surveys.

Commenter (2315-New York State Department of Environmental Conservation (NYSDEC) appreciates EPA's proposal to allow for alternative technology through a matrix approach, but there are considerations beyond the detection limit that should be considered to ensure appropriate alternative detection technology is selected. The commenter recommends that EPA convene a multi-faceted workgroup to sort and evaluate detection technology most appropriate for recommendation. A similar effort took place through the Environmental Council of States Interstate Technology & Regulatory Council (ECOS's ITRC) program in 2017, where a document was generated to evaluate detection technology.<sup>34</sup> The commenter recommends EPA convene a similar group here.

Response II-5-75: EPA acknowledges the commenter's input.

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<sup>34</sup> <https://methane-1.itrcweb.org>.

#### 5.8.4 Proposed Requirements

Comment: Commenter (2235-SLB) indicates that for alternative period screening using advanced methane detection technologies, the proposed regulations contain many additional elements that can complicate an operator's use of alternative screening. These additional elements and requirements can inadvertently discourage use of advanced technologies over the straightforwardness of the prescribed approach using older technology. These additional elements do not relate directly to the performance or effectiveness of the proposed alternative technology but rather amount to additional work not tied to technology selection. Examples of such additional elements required for alternative period screening beyond what is required for AVO and/or OGI fugitive emissions monitoring include:

- §60.5398(b)(1) (vi and vii) – requiring procedures and timeframe for identifying and repairing fugitive emissions in the fugitive emissions monitoring plan. This would require the upfront monitoring plan to anticipate all possible points of emissions and describe how to repair them prior to determining the source and nature of an emission.
- §60.5398(b)(4)(i) – requiring receipt of periodic screening in no less than 5 calendar days.
- §60.5398(b)(4)(ii) – in the event of a confirmed detection from periodic screening, a full site OGI survey or Method 21 must be conducted, with no option for AVO, notwithstanding that AVO is the default at single well facilities under the prescribed approach.
- §60.5398(b)(4)(iii) – a root cause analysis must be initiated to determine cause of failure and determine corrective action within 24 hours of the monitoring survey and inspection. “Root cause analysis should include a determination as to whether the system was operated outside of the engineering design analyses and whether updates are necessary for the system.” In some instances, regardless of whether the detection technology is OGI, AVO, or an advanced alternative, the cause of an emission may be readily available (*e.g.*, an ajar thief hatch) rendering a root causes analysis of the engineering design of the system unnecessary. Requiring root cause analysis for any detection made by an advanced alternative technology creates an additional burden for use of that alternative technology on an operator or technology provider and acts as an impediment to its use.

Each one of these additional elements, any combinations, or all collectively may discourage implementation or hamper implementation of an advanced screening technology by virtue of the additional work or constraints applied to alternative periodic screening.

Response II-5-76: EPA acknowledges the commenter's input. EPA has made some revisions consistent with these comments, for discussions on the periodic screening using alternative technology, please see sections X.B.1 and XI.B.1 of the preamble to the final rule.

Comment: Commenter (2433-EDF *et al.*) believes that AVO inspection requirements should apply to sites opting for alternative periodic screening. Aerial screening does not serve the same site upkeep and preventative maintenance purposes as AVO inspections. Allowing sites opting for the alternative to forgo AVO inspections means they may not be visited for years (depending on where in the matrix they fall) and could therefore fall into states of neglect and disrepair,

making them more prone to leaks and equipment failures that might be under the detection limit of the screening technology. Including these sites in AVO requirements is also important for ensuring the equivalency of emissions reductions.<sup>35</sup>

Response II-5-77: EPA acknowledges the commenter's input.

Comment: Commenter (2405-Bridger) states OGI inspections and M21 are methane emissions screening approaches that would fit into the periodic screening framework in the Proposed Rule. Implementing their use for regulatory LDAR using the same provisions that apply to other methane sensing technologies is consistent with the EPA's goal to approve emissions monitoring options based on their performance. To implement these monitoring approaches in the same systematic manner as other technologies, the EPA would establish a sensitivity/scan frequency tier in the periodic screening matrix that corresponds to the performance of these technologies.

Commenter (2405-Bridger) argues to determine the sensitivity corresponding to OGI and M21, further research may be necessary. Performance needs to be demonstrated through analysis studies representative of field conditions commensurate with the requirements for other monitoring approaches. Although OGI cameras and the detectors used for M21 are highly sensitive, their field performance is subject to environmental conditions, user error, and survey procedures. One research study indicated that surveys completed with a flame ionization detector according to M21 and surveys completed at the same sites with OGI detected a similar volume of emissions,<sup>36</sup> meanwhile another study indicated that existing advanced methane sensing technology detected a greater volume of emissions than OGI indicating the need for more research into the capacity of M21 and OGI to comprehensively identify emissions during field deployment.<sup>37</sup> As previously discussed in Comment 2.2, under simulated field conditions, experienced OGI surveyors reached 90% PoD at ~135 g hr<sup>-1</sup> (less experienced surveyors had reduced performance; they never achieved 90% POD for any emission rate).

Response II-5-78: EPA acknowledges the commenter's input.

Comment: Commenter (2283-Endeavor Energy Resources, L.P. (Endeavor)) believes EPA should revise the fugitive emissions testing requirements to reflect the realities of upstream oil and gas operations and provide additional flexibility for operators to use new, evolving, and more cost-effective methods of leak detection.

Response II-5-79: EPA acknowledges the commenter's support for the alternative technology approach in the rule.

Comment: Commenter (2283-Endeavor) states the proposed LDAR requirements ignore operational realities and as a result would impose unjustified burdens on the oil and gas industry. As noted above, well sites in the areas where the commenter operates, such as the Midland

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<sup>35</sup> See Supplemental RIA, *supra* note 110, at 235.

<sup>36</sup> Pacsi, A. P. et al. Equipment leaks detection and quantification at 67 oil and gas sites in the Western United States. *Elementa* 7, (2019).

<sup>37</sup> Tyner, D. R. & Johnson, M. R. Where the Methane Is - Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data. *Environ Sci Technol* 55, 9773–9783 (2021).

Basin, are often in remote locations, geographically spread out, and do not have permanent on-site staff. As a result, any provisions in the Methane Proposal that would require on-site personnel to perform a task presents a meaningful cost and operating challenge for producers. This is all the truer when these requirements are tacked on to existing sources under proposed Subpart OOOOc. Unless EPA allows for remote monitoring, the requirements will be unworkable and arbitrary and capricious in violation of the Administrative Procedures Act. The best approach is one that balances regulatory certainty with flexibility; to that end, The commenter recommends that EPA include a non-exhaustive list of methods of inspection that can be used, including aerial and remote-sensing options, as well as a clear and efficient process for additional methods not included on the list to be recognized and approved by the agency.

Response II-5-80: The use of alternative technology in the periodic screening or continuous monitoring approach in the final rule are alternatives to the BSER. EPA has provided a pathway for these to be approved for use, but it is inappropriate for the EPA to approve technology without thorough review.

Comment: Commenter (2283-Endeavor) adds there are simply not enough technicians in the Midland Basin to comply with the new requirements. EPA's current proposal would require periodic in-person monitoring. Based on the commenter's past experience, they estimate that one LDAR technician is needed to comply with current Subpart OOOOa LDAR requirements for every 40 sites. The commenter estimates that it would need to at least triple the number of LDAR technicians it employs to comply with the Methane Proposal, and this proposed requirement would represent millions in additional costs when multiplied across all operators in the Midland Basin. EPA's proposal will significantly strain the capacity of existing LDAR technicians and there are real concerns about the ability to scale up additional support. In addition, operators like the commenter would need additional resources to perform the monitoring (*i.e.*, purchase additional OGI camera at a cost of approximately \$100,000 per camera) and respond to any leaks. This would simply be cost-prohibitive for most producers, particularly as applied to low producing wells, and the Methane Proposal therefore risks driving producers to plug and abandon wells sooner than they would otherwise because this proposal is simply not economically viable, especially for the many low-producing wells that will be subject to EPA's proposal.

Commenter (2283-Endeavor) argues EPA should instead allow periodic inspections to occur through aerial flyovers or through the use of other remote technology and only require in-person monitoring on a much less frequent basis. Due to the remote locations of many of the sites that would be covered by the Methane Proposal, one technician might be able to visit three sites in a day through on-the-ground inspection. By contrast, an aerial inspection could inspect 200 sites at the same time. Aerial flyovers therefore allow operators to respond to leaks in real time in a more cost-effective way. Based on its own operations and experience, The commenter estimates that producers in the Midland Basin would save millions in compliance costs if EPA allowed for the use of aerial inspections in lieu of in-person inspections. This approach comes with air emissions benefits as well: it would drastically decrease the truck traffic needed to make these site visits and would allow operators to respond much quicker to any fugitive emission leaks found during the inspections. It would also avoid diverting operators' compliance resources from spending all of their time simply driving from site to site and allow them to instead focus on sites with known

leaks. EPA can therefore better address its true concerns through this flexible approach. And notably, EPA has included aerial flyovers as an accepted method of gathering information about fugitive emissions under its proposed Super-Emitter Response Program. While the commenter has concerns with the Super-Emitter Response Program and EPA's inclusion of aerial flyovers in the proposed program indicates that EPA has found this to be a reliable method of detecting emissions. It would be arbitrary (in violation of the APA) for EPA to allow for the use of aerial flyover monitoring in one part of the rule without allowing for its use in LDAR monitoring. EPA should therefore allow operators the flexibility to use this same approach for monitoring. At the very least, EPA's cost estimates should accurately reflect both the monetary costs of in-person surveys as well as the additional emissions that would result from such surveys.

Response II-5-81: EPA acknowledges the commenter's support for the alternative technology approach in the rule. The purpose of this rule is to provide a pathway to use these technologies within the rule to incentivize potentially cost-effective measurement solutions in identify excess methane emissions.

EPA has not pre-approved any technology for use in the alternative periodic screening or continuous monitoring approaches.

#### ***5.8.5 Follow-up OGI/Emissions Localization***

Comment: Commenter (2405-Bridger) states when an emission is detected by periodic screening, the Proposed Rule requires a full-site OGI survey to determine the source of the detected emission and any other fugitives present. However, many advanced methane sensing technologies have equipment scale resolution, and it is redundant and burdensome to require an OGI survey of all equipment pieces at a site to locate the emission source, which has already been identified to belong to a single equipment unit. It is a standard practice to use OGI to determine the specific emitting component by screening infrastructure within the localization uncertainty of the methane sensing technology. When OGI is an appropriate element of investigative analysis for an emission detected by advanced technologies, the commenter urges the EPA to allow operators to direct the OGI survey within the localization uncertainty region of the advanced technology. This practice maintains the efficiency gained by technologies that can rapidly screen oil and gas sites for emissions and precisely localize emission sources.

Commenter (2405-Bridger) notes FEAST modeling was used to support the periodic screening framework development. Modeling efforts simulated periodic screening as aerial surveys with site-level resolution. In the simulation protocol, emission detection at a site triggered a full-site OGI survey. Although this approach was based on prior literature,<sup>38</sup> it is not suitable for modeling a technology agnostic framework. Various methane sensing technologies that could be used in this framework have localization capabilities spanning site-level, equipment group-level, equipment unit-level, and component-level precision. For technologies with site level localization, a large set of infrastructure may need to be investigated to conclusively identify emissions sources. For technologies that can localize emissions to specific components

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<sup>38</sup> Kemp, C. E. & Ravikumar, A. P. New Technologies Can Cost Effectively Reduce Oil and Gas Methane Emissions, But Policies Will Require Careful Design to Establish Mitigation Equivalence. *Environ Sci Technol* 55, 9140–9149 (2021).

additional emissions screening is redundant. It is foreseeable that advanced handheld instruments, unmanned aerial vehicle-mounted sensors and/or aerial technologies will provide component-level resolution and be used for periodic screening. The commenter urges the EPA to develop regulations that recognize the localization capabilities of advanced methane sensing technologies and encourage technological improvement in this area. Follow-up requirements for emissions detected by alternative test methods should be guided by the known capabilities of advanced methane sensing technologies. Extensive studies have been performed to characterize emission source localization such as those completed at the METEC which was developed with support from the Department of Energy's Advanced Research Program Agency-Energy (ARPA-E).<sup>39,40,41</sup> These studies categorize localization precision as site-level, equipment group-level, and equipment unit-level precision. The commenter recommends the EPA to refine alternative emissions monitoring follow up requirements to correspond to these localization precision levels. For a test method to be classified at a given level of localization precision, 95% of its detections should be correctly localized.

Response II-5-82: EPA acknowledges the commenter's input. As explained in Section X.B.1, X.B.3, XI.B.1, and XI.B.3, EPA has revised the final rule include allowances for technologies which have proven spatial resolution.

Comment: Commenter (2333-LongPath) states several groups and coalitions have recommended that OGI follow-up for certain types of emissions may be unnecessary and inadvertently disadvantage alternative technologies compared with BSER. For example, if permitted process emissions are detected and conclusively identified as permitted, then OGI follow-up should not be required. Similarly, if emissions are identified as intermittent, then follow-up OGI may be unlikely to find or provide any additional information about the source and therefore be unnecessary. Continuous monitoring provides temporal information about emissions that can typically lead to the identification and resolution of the cause without requiring a site visit or OGI survey. Indeed, EPA's continuous monitoring provisions do not require OGI follow-ups in any scenario. The commenter therefore recommends that for technologies that can provide information contributing to understanding of the cause of the emission, including information about the temporal nature of the emission (*e.g.*, intermittency) or links to maintenance or permitted processes, that OGI follow-ups not be required as part of the "root cause analysis" (like other stakeholders, the commenter prefers the term "investigative analysis").

Commenter (2192-BSM) responds to the requirement for a monitoring plan to include "(5) procedures for conducting ground-based monitoring surveys in response to confirmed emission detection events from periodic screening surveys." The commenter requests that the process for reporting a "confirmed emission detection" allow for the possibility of measurement verification. One of the major benefits of a fixed position system like NIRview is the ability to quickly validate with either automatic scan repeats or even by remote control via user-directed "point and

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<sup>39</sup> Ravikumar, A. P. et al. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. *Elementa* 7, (2019).

<sup>40</sup> Bell, C. S., Vaughn, T. & Zimmerle, D. Evaluation of next generation emission measurement technologies under repeatable test protocols. *Elementa: Science of the Anthropocene* 8, (2020).

<sup>41</sup> Bell, C., Ilonze, C., Duggan, A. & Zimmerle, D. Performance of continuous emission monitoring solutions under single-blind controlled testing protocol. *Chem xiv* (2022). doi:10.26434/chemrxiv-2022-4hc7q-v2.

measure” operation. The commenter would like to make sure that if an advanced measurement technology has a means of measurement validation that it be allowed to be incorporated into the process of providing a confirmed emission detection event.

Response II-5-83: EPA acknowledges the commenter’s input. As explained in sections X.B.1 and XI.B.1 of the preamble to the final rule, EPA has revised the final rule to include allowances for technologies which have proven spatial resolution to conduct reduced follow-up. See response II-5-19 for further discussion.

Comment: Commenter (2298-Pioneer) recommends that EPA change the full-site follow-up requirement to a follow-up OGI survey only over the spatial extent corresponding to the verified localization performance of the detection technology.

Commenter (2298-Pioneer) says that third parties (*e.g.*, METEC) are currently in place to characterize and document the emission source localization performance of methane detection technologies just as they do for detection sensitivity performance. Rather than requiring a full-site follow-up OGI survey, the commenter urges the EPA to require an OGI follow-up survey only over the spatial extent corresponding to the detection technology localization performance. By way of example, if a detection technology has proven emission source localization performance of 2-meter radius with 95% confidence bound (*e.g.*, verified by METEC under the ADED protocol), then the follow-up OGI survey must only be performed over a radius of that spatial extent and a follow-up OGI survey of the remainder of the site would not be required. However, if a sitewide OGI inspection sweep is performed to identify the emission component source, the commenter agrees with EPA that such an OGI sweep would satisfy any required annual OGI screen if that is required for that specific technology or under the matrix.

Response II-5-84: EPA acknowledges the commenter’s input. As explained in Section X.B.1, X.B.3, XI.B.1, and XI.B.3, EPA has revised the final rule include allowances for technologies which have proven spatial resolution to conduct reduced follow-up.

Comment: Commenter (2336-Kuva) argues a “blanket” follow-up OGI survey for emissions detected by advanced technology in the periodic screening matrix conflicts with emissions reduction goals and disincentivizes advanced technology. Advanced technologies may detect, record, and characterize many emission sources for which OGI follow-up is unnecessary or impractical.

Commenter (2336-Kuva) states operators may be able to conclusively identify the emission source through investigative analysis other than OGI using a combination of advanced technology data, compressor runtime data, process control / SCADA data, maintenance activity logs, and prior screening results. In these cases, an OGI survey is unnecessary and burdensome. Moreover, OGI is impractical for following up on emission sources such as compressor engines and control devices because OGI cannot inherently differentiate between normal and abnormal operation. These emission sources are regularly detected by advanced technologies even when normally operating. If permitted process emissions are detected and conclusively identified, then no response other than recordkeeping should be necessary. For emissions identified as intermittent or nonpersistent (*e.g.*, those coming from over-pressurization of a closed vent system



or a maintenance event) additional OGI screening is unlikely to be helpful and investigative analysis (especially with camera based continuous monitoring systems) is the appropriate response.

Response II-5-85: EPA acknowledges the comments and agrees that when a technology identifies emission event from a maintenance event should trigger an OGI inspection, however we disagree that an OGI inspection of an emission event of a closed vent system is not an appropriate response. It is critical to identify the cause of the emission event and to ensure that a release has not moved to another portion of the CVS system.

Commenter (2336-Kuva) states the Proposed Rule for periodic screening burdens each detected emission by an advanced technology with a full-site follow-up OGI survey despite the fact that the advanced technology may localize the emission source with better than site-level uncertainty. Therefore, when an OGI follow-up is appropriate, the commenter urges the EPA to require follow-up OGI surveys only within the localization uncertainty region of the advanced technology. By way of example, if an advanced technology has emission source localization performance of 2-meter radius with 95% confidence bound, then the follow-up OGI survey must only be performed over that spatial extent and a follow-up OGI survey of the remainder of the site is not required. Advanced technology localization performance is readily characterized by third parties using consensus testing protocols (*e.g.*, the ADED protocol).

Response II-5-86: EPA acknowledges the commenter's input, as explained in Section X.B.1, and XI.B.1, EPA has revised the final rule include allowances for technologies which have proven spatial resolution to conduct reduced follow-up.

Commenter (2345-GHGSat Inc.) agrees with requiring operators to conduct a root cause analysis to determine the corresponding corrective action within 24 hours and completion of repairs must occur within 30 days of notification from the screening survey. The commenter believes that this corrective action should be coupled with a first attempt to repair the leak, which may involve a temporary solution to minimize emissions (*e.g.*, emission source isolation, temporary replacement, etc.). These efforts should grant additional time to make a permanent repair in the event that the emission source is not fully resolved within 30 days of notification. Therefore, this should grant a delay-of-repair status, requiring an operator to fully document and amend, if necessary, the corrective action plan.

Commenter (1686/2345-GHGSat) understands that the EPA is proposing to perform a root cause analysis within 5 days of completing a ground-based inspection when a leak or defect in a cover or CVS is identified. Also, the EPA requires repairing the leak or defect within 30 days of the screening survey. The commenter believes that an initial root cause analysis should be performed within 24 hours, as it would be the standard practice in the event of a different type of emission source (*e.g.*, leaky valve). Adding a different timeline for covers and CVS just adds to the complexity of the rule and does not necessarily alleviate any burden. Most likely that companies will opt to make a 24-hour deadline across the board. Also, the commenter would like to stress to change the language to reflect that repairs must occur within 30 days upon notification, and not at the time when the emission source was identified.

Commenter (1686/2345-GHGSat) argues when emissions originate from sources like cover, CVS, or a control device, a root cause analysis must be conducted. In addition, this root cause analysis should provide an avenue for the operator to claim affirmative defense, when applicable.

Response II-5-87: In the final rule, EPA no longer uses the term root cause and instead has chosen the term investigative analysis when a confirmed detection was caused by a failure of a control device used to demonstrate continuous compliance in the applicable regulation. The criteria for the cover and closed vent systems are detailed in Section X.K and XI.K of the preamble of the final rule.

Comment: Commenter (2405-Bridger) argues the 30-day timeline for repairing emissions detected during periodic screening does not allow operators enough time to follow up on detected emissions. Certain advanced methane sensing technologies that will be used for periodic screening can cover 100+ sites in a single day. This level of efficiency is a major reason that operators benefit from access to these technologies. Compared to the ~5 sites per day that can be screened by OGI,<sup>42</sup> efficient aerial screening would generate a much larger workload of follow-up repairs in a short period of time. To overcome this challenge, the EPA should allow a longer repair timeline for emissions detected during periodic screening. It is also necessary to consider time needed for data to be fully processed before it is delivered to operators. Operators typically wait for fully processed datasets, which contain mass emission rates that they use to prioritize repair activities. More time is warranted to allow emissions data to be processed and delivered to operators. The commenter urges the EPA to allow operators 45 days for a first repair attempt on emission sources detected during the periodic screening alternative approach.

Response II-5-88: EPA acknowledges the commenter's input, and EPA has chosen to maintain the timeline criteria for repairing emissions for the periodic screening, as the 30-day repair timeline is consistent with the requirements for the BSER program for which the equivalent emission reduction in the matrix framework was based.

Comment: Commenter (2428-API) expresses that the proposed follow-up actions for periodic screening surveys should be revised. The proposed repair or corrective action requirements for alternative technology should not disincentivize their use. The commenter offers the following suggestions:

- The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion. **The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.**
- The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days. **Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.**

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<sup>42</sup> Zimmerle, D. et al. Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environ Sci Technol 54, 11506–11514 (2020).

- Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information. **Follow-up OGI** surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2 and described in detail below.

[Figure 2. Flowchart of proposed follow-up for Periodic Screening Surveys]

Commenter (2428-API) states when emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be able to conduct one based on the localization performance of the technology or an optional full site survey.

Commenter (2428-API) notes if the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated

from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey. The commenter provides additional recommendations below (more specific details on these recommendations can be found in the commenter's letter):

- Repair timelines should be consistent with AVO/OGI requirements.
- The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.
- The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.
- "Root cause analysis" should be replaced with "investigative analysis".

Response II-5-89: EPA acknowledges the commenter's input. EPA has made changes to the periodic screening approach in the final rule as detailed in Section X.B.1 and XI.B.2. EPA has not made changes to the follow-up or repair timelines in the proposed rules.

Comment: Commenter (2406-EEMDL) states screening technologies are more likely to detect emissions at the equipment-level, thus making a targeted follow-up OGI survey more cost-effective than a site-wide OGI survey.

Response II-5-90: EPA acknowledges the commenter's input, as explained in Section X.B.1, and XI.B.1, EPA has revised the final rule include allowances for technologies which have proven spatial resolution to conduct reduced follow-up.

Comment: Commenter (2298-Pioneer) recommends that EPA exclude from the follow-up OGI survey requirement those emission sources corresponding to normal permitted operating process emissions or emission events that are otherwise confirmed to no longer exist.

Commenter (2298-Pioneer) indicates that emissions corresponding to normal operating process emissions that are within permitted bounds are not considered fugitive emissions affected facilities. Moreover, emissions corresponding to temporary process disruptions are often clearly identified and documented in operations and SCADA logs. If an emission event can be attributed with certainty as a normal operating process release, then a follow-up OGI survey should not be required. By way of example, if an emission was identified during one application of an alternative test method and verified to correspond to a normal operating process release with a follow-up OGI survey, then a subsequent identification of that emission source should not require a subsequent follow-up OGI survey. Similarly, a well-documented process upset detected during application of an alternative test method should be addressed by root cause analysis (or rather "investigative analysis" per comments below) and should not require follow-up OGI surveys. In both examples, the follow-up OGI survey does not reduce emissions, but could unnecessarily increase safety risk and economic burden associated with the follow-up OGI survey.

Response II-5-91: EPA acknowledges the commenter’s input, as explained in Section X.B.1, and XI.B.1, EPA has revised the final rule include allowances for technologies which have proven spatial resolution. When an operator uses a technology that can differentiate permitted releases (e.g., methane slip from an IC engine) from equipment covered in the periodic screening, you are not required to conduct a follow-up inspection. You must maintain a record of the survey and maintain a record why follow-up was not conducted.

Comment: Commenter (2435-Will Price) urges EPA to make the following two “make or break” revisions to rule based on the fundamental principle of removing inadvertent “penalties” or “disincentives” for detecting emissions under the alternative framework:

1. Provide an opportunity for operators to mitigate detected compliance issues instead of immediately classifying them as violations. With more comprehensive spatial and temporal coverage, advanced technologies will detect many more emission sources than OGI that represent compliance issues (e.g., malfunctioning control devices, cover and closed vent system failure). Penalizing operators with an immediate violation/fine create a strong disincentive inhibiting adoption of advanced technologies that will reveal these problems. Allow the operators a compliance pathway to fix the problem first.
2. Capitalize on the enhanced capabilities of advanced tech instead of requiring a “blanket” full-site follow-up OGI survey. Every detection by advanced tech triggers a “full-site” follow-up OGI survey, even if the tech identifies the emission source, even if the emission source is not required to be monitored by standard OGI (compressor exhaust), and even if the advanced tech shows the emission source no longer exists (intermittent). This penalizes the detection of emission sources and favors standard OGI. To remove this disincentive, the commenter suggest that EPA do not require OGI follow up if the emission source can be conclusively identified by the advanced technology or is intermittent. If it cannot be identified, the commenter suggests only requiring OGI follow up within the localization uncertainty of the advanced technology investigative analysis.

The commenter notes that requiring blanket OGI surveys unfairly saddles advanced technologies with OGI inefficiencies.

Response II-5-92: EPA acknowledges the commenter’s input, as explained in Section X.B.1, and XI.B.1, EPA has revised the final rule include allowances for technologies which have proven spatial resolution. EPA has explained its position on covers and closed vent systems in Section X.K and XI.K.

### ***5.8.6 OGI Requirements are Duplicative***

Comment: Commenters (2284-Kairos, 2298-Pioneer, 2345 GHGSat Inc., 2363-CEMC, 2428-API) agree with the EPA’s proposal to require a ground-based survey using OGI to identify the source of the emissions when periodic screening survey technologies are used. The commenters argue in turn, the full site follow-up OGI survey fulfills the annual OGI survey requirement, when applicable, as indicated in §60.5398b(b)(3)(iii).

Response II-5-93: EPA acknowledges the commenter's input and EPA agrees that a full-site follow-up would fulfill the annual OGI survey requirements in the matrix framework.

Comment: Commenters (2258-MS, 2284-Kairos, 2399-GPA) are not supportive of the requirement to conduct a full survey following a periodic screening.

Commenter (2399-GPA) states the proposed regulatory text offers the option of periodic screening, but if a leak is detected, the owner/operator would be required to conduct a full survey of every fugitive emission component. This would practically be the same monitoring requirement found in proposed §60.5397b. Thus, the periodic screening option not only provides no real benefit over quarterly monitoring with an annual OGI inspection, but it adds the cost of periodic screening – which would be a significant additional cost, where an owner or operator must also conduct bi-monthly or monthly screening. To make the periodic screening option meaningful, the commenter proposes that, for owners or operators that choose the periodic screening option, follow-up inspections be focused on the identified source of the leak instead of the entire facility.

Commenter (2258-MS) states the proposed requirement of a ground-based monitoring survey of the entire facility when emissions are identified by alternative technology are burdensome and not necessary in all cases. The requirement to assess the full facility with OGI following detection of emissions should be dependent on the capability of the alternative technology used. Many technologies can detect source level emissions. In this case, only the source should be evaluated. Cause(s) of emissions identified by alternative technology are often documented by other records. A facility/source level inspection should only be required if the cause cannot be identified by separate records such as operator logs, SCADA data, etc.

Response II-5-94: EPA acknowledges the commenter's input, EPA in maintaining OGI follow-up when periodic screening when emissions have been detected with periodic screening, but the final rule includes an allowance for a reduced screening when using technology with better spatial resolution. EPA considered the use of supplemental records such as SCADA data to be valuable, however they are not replacement for component-level inspection.

Comment: Commenter (2258-MS) states when OGI is necessary, the requirements in §60.5398b(b)(4)(iv) using the term “ground-based monitoring survey” should be removed. The term “ground-based monitoring survey” can be interpreted to exclude the ability to use OGI cameras mounted to drones or aircraft. The commenter believes the daily verification requirements that exist in the proposed rule §60.5397b(c)(7) and 40 CFR 60.5397a(c)(7) are sufficient to determine the distance at which the OGI camera can view the release, and the OGI inspection must be performed within that distance.

Response II-5-95: EPA disagrees that the terminology in §60.5398b needs to be revised. The terminology is not meant to limit how an owner or operator uses an OGI camera; it is meant to differentiate the OGI survey from surveys that will be conducted with alternative methane detection technologies. EPA considers a drone-based OGI inspection to still be ground-based, because the drone operator is located on the ground. EPA has previously acknowledged that the use of OGI cameras mounted to drones are acceptable for fugitive emission surveys in NSPS

OOOOa, so long as the criteria outlined in §60.5397a are met.<sup>43</sup> EPA has received numerous questions on this issue since that time, and we think it is important to clarify that when using an OGI camera mounted to a drone, the person who is trained and knowledgeable on the operation of the OGI camera should either be the person operating the drone or be viewing the results alongside the person operating the drone in order to make appropriate adjustments for interferences and background during the survey as needed – the results cannot be sent to the person trained and knowledgeable on the operation of the OGI camera after the inspection. Additionally, EPA does not believe that OGI cameras mounted on aircraft will meet the requirements in NSPS OOOOa or §60.5397b. The aircraft is likely to create wind effects that will disperse emissions, making them harder to detect. Additionally, it will be much harder for an OGI camera operator to have a proper thermal background for monitoring all components from an aircraft.

Comment: Commenter (2284-Kairos) suggests EPA broaden its ground follow-up for more rapid repairs and consequently, emission reductions. If a remote sensing technology flags a site for follow-up, the first visit of the year should conduct a comprehensive site survey, either via OGI screening or an alternative approved method. This should continue to satisfy the annual OGI requirement, as proposed by EPA. It also will align the alternative leak detection program with EPA's modeled emission reductions under the proposed matrix. The commenter states if a site is flagged by remote sensing technology for follow-up on subsequent surveys that year, operators should be able to survey the suspected source using OGI or an alternative approved method but should NOT be required to do a comprehensive site screening for small, unrelated emissions from process units clearly not associated with the flagged emission. For example, if an aerial survey identifies a site with emissions near the separator, and ground follow-up confirms a malfunctioning dump valve, that should be sufficient investigation for follow-up and repair. The operator in this instance would not need to conduct an OGI survey of an onsite compressor located on the far side of the facility that clearly was not the source of the emissions in the remote sensing survey. The commenter adds follow-up ground truth verification is extremely valuable—even the most precise aerial systems generally cannot definitively establish a root cause by themselves. OGI is a useful tool for ground truth verification, but the commenter recommends EPA allow other appropriate technologies (*e.g.*, a continuous monitoring system) to aid in that ground follow-up action. OGI should not be the only tool available, when other measurement systems can perform this same task.

Response II-5-96: The final rule now includes considerations for spatial resolution when conducting follow-up as described in Section X.B.1 and XI.B.1 in the preamble of the rule.

Commenter (2284-Kairos) argues by focusing on the large emission sources identified by screening technologies and prioritizing work practices around rapid repair, EPA will ensure these emission sources are addressed as quickly as possible. Similarly, by leaving the annual OGI screening (or another approved alternative method) as a part of the work practice, EPA can

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<sup>43</sup> EPA's Responses to Public Comments on the EPA's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. May 2016. Page 4-184. Available at: <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-7632>.

address Environmental Justice concerns that stem from the impact of unaddressed small leaks on local communities.

Commenter (2284-Kairos) summarizes their findings with the following recommendations:

- In addition to OGI, include other appropriate ground-based technologies as acceptable means of ground follow-up (*e.g.*, continuous monitoring systems).
- Leave requirements for comprehensive ground survey resulting from an advanced leak screening survey in place for the first site visit of the year resulting from a remote survey detection.
- Require subsequent visits resulting from remote survey detections to the same site to survey the impacted area/suspected emission source using an appropriate ground-based measurement technique (OGI survey or approved alternative method). Interpretation of SCADA data or AVO surveys may not always be sufficient based on our experience.

Response II-5-97: EPA acknowledges the commenter's input. EPA has detailed the requirement for follow-up to periodic screening in Section X.B.1 and XI.B.1 in the preamble of the rule.

Comment: Commenter (2363-CEMC) states that the proposal does not require operators to conduct this additional OGI sweep when monitoring fugitive emissions with OGI because OGI can sufficiently identify the location of the leaking component. Some advanced technologies can similarly identify the leaking fugitive emission component or process malfunction, thereby rendering follow up OGI duplicative for the purposes of identifying the source or cause. To identify the emission source, an operator might use the advanced technology's spatial and temporal information in conjunction with data analysis of process or runtime data. Alternatively, an operator may be able to use combinations of advanced technologies (*e.g.*, an aerial survey to comply with the fugitive emission requirement coupled with a continuous emission data) to identify the emission. A mandatory OGI sweep will create a disincentive for operators to deploy advanced technologies for compliance with the rule if that advanced technology can localize the emission to a component, identify the emission as normal or abnormal, or identify its root cause.

Response II-5-98: EPA acknowledges the commenter's input.

Commenters (2363-CEMC, 2405-Bridger) alternatively recommend that EPA design the final rule to allow operators to choose the most effective follow up response based on the advanced technology's capability to identify the emission cause.<sup>44</sup> EPA should consider providing more choices on how to respond when emissions are detected, similar to the approach used in the fenceline monitoring work practice promulgated by EPA in 2015 as part of the NESHAP for the petroleum refinery sector.<sup>45</sup> Under that rule, if an operator determines an action level exceedance, the operator must initiate an investigative analysis which may include: leak detection using Method 21, leak detection using OGI, or employing progressively more frequent sampling using

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<sup>44</sup> This recommendation is in response to EPA's request for comments: "The EPA is soliciting comment on the proposed requirements for the root cause analysis and corrective action, the timeframes for conducting these activities, and the requirement for corrective action plan submittals." 87 Fed. Reg. 74745.

<sup>45</sup> See 80 Fed. Reg. 75178 (Dec. 1, 2015).



Method 325A and 325B.<sup>46</sup> In the preamble of that rule, EPA stated that “the premise of the fenceline monitoring is to provide the refinery owners or operators with the flexibility to identify the most efficient approaches to reduce the emissions that are impacting the fenceline level.”<sup>47</sup> The commenter recommends providing similar options for operators to use advanced technologies to efficiently fix leaks in the Final Rule.

Response II-5-99: EPA acknowledges the commenter’s input. EPA could consider an alternative to an OGI follow-up so long as the technology and methodology associated with the technology would yield the same level of detection probability as OGI.

Commenter (2405-Bridger) adds in addition to source identification, the OGI follow-up requirement was also developed to identify the presence of emissions that were not identified by advanced technology screening. However, this approach conflicts with the EPA’s mission to develop a framework for emissions monitoring that is performance based and technology agnostic. For the framework to fit these criteria, the desired emission reductions must be achieved by the alternative test method itself and not hinge on supplemental screening with OGI cameras to detect additional emissions at sites where emissions are detected by an alternative approach. Moreover, for sensitive technologies, the impact of searching for additional emissions will be minimal even though the Proposed Rule burdens increased sensitivity with a greater number of sites requiring OGI follow-up (as previously discussed).

Commenter (2405-Bridger) states although a full-site OGI scan should not be required every time an emission is detected at a site, if annual OGI is required at the periodic screening sensitivity tier being used, then operators should have the option to complete a full-site OGI survey during detection follow-up to satisfy the yearly OGI requirement at that site. This could improve operations efficiency and reduce a backlog of sites that need to be visited for yearly OGI. This recommendation is consistent with the November 2021 Proposed Rule.

Response II-5-100: EPA acknowledges the commenter’s input and EPA agrees that a full-site follow-up would fulfill the annual OGI survey requirements in the matrix framework.

Comment: Commenter (2363-CEMC) recommends that the final rule require that if an advanced technology confirms an emission detection, the operator should identify the emission source or cause.<sup>48</sup> The Final Rule need not specify only one option to identify the component releasing the emissions. Instead of automatically requiring a sitewide OGI sweep, the Final Rule should require operators to use:

- an advanced technology that EPA approves to identify the emission source or cause.
- an advanced technology combined with any relevant process data analysis to identify the emission source or cause.

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<sup>46</sup> 40 CFR 63.658(g).

<sup>47</sup> 80 Fed. Reg. 75198.

<sup>48</sup> To the extent the Final Rule reflects this change, it would be important to update any modeling assumptions used in the FEAST modeling.

- advanced technology coupled with a continuous emission monitor<sup>49</sup> to identify the emission source; or
- OGI or Method 21 to identify the emission source.

Commenter (2363-CEMC) suggests that once the operator identifies the emissions source, the operator's obligation should be to repair all sources of fugitive emissions and initiate an investigative analysis for all process malfunctions. EPA can establish the requirements for an advanced technology's capability to localize a confirmed emission detection through work practice standards in the alternative test method approval process.<sup>50</sup>

Response II-5-101: EPA acknowledges the commenter's input; we have revised the final rule to include many of these suggestions which are explained in Section X.B and XI.B of the preamble of the rule.

Comment: Commenter (2298-Pioneer) recommends that if any degree of OGI follow-up remains a requirement, a leak detected with aerial technology must be confirmed by a second fly over pass to determine it is a nonintermittent event that triggers the follow-up.

Commenter (2298-Pioneer) recommends that EPA include language stating that before any degree of OGI follow-up is required, the emissions must be detected by the aerial technology twice: 1) an initial flight pass that identifies the leak; and also 2) a second flight pass to confirm the leak. In regard to the commenter's voluntary program with Bridger Photonics, Bridger routinely takes this approach and factors this confirmation pass over an initially detected leak into their services and cost structure. If they detect a leak, they fly over it a second time to confirm the leak and make sure it was not a random intermittent release that the OGI thermographers likely would not find if they went to the site. The timeframe between the two flight passes is typically within 2-3 days in order to let any one-time event like truck loading or a pneumatic actuation cease.

From the commenter's (2298-Pioneer) experience, the inclusion of this requirement will not impose an added disincentive for an operator to utilize an alternative aerial technology but rather will incentivize this technology by confirming leaks, thus avoiding futile ground truth efforts that will waste manpower hours.

Response II-5-102: EPA acknowledges the commenter's input, however EPA is unable to respond to this specific scenario without additional information. EPA has revised the periodic screening approach and alternative test method approval process in the final rule as detailed in Section X.B and XI.B of the preamble of the final rule.

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<sup>49</sup> EPA could approve the use of a continuous emission monitor to identify the emissions source through an operator's site-specific monitoring plan.

<sup>50</sup> For example, the Methane Emissions Technology Evaluation Center (METEC) has developed such protocols with support from the Department of Energy.

### **5.8.7 FEAST Modeling/Equivalency**

Comment: Commenters (2284-Kairos, 2340-Honeywell) believe the periodic screening framework should provide further flexibility based on the use of FEAST modeling.

Commenter (2284-Kairos) indicates that to fully characterize the benefits of advanced leak detection technology, FEAST modeling should incorporate the additional indirect emission reductions generated by using advanced technology in lieu of AVO inspections. EPA could incentivize these more rigorous advanced solutions by allowing operators to eliminate AVO visits with advanced screenings. For example, a monthly aerial screening program at 30 kg/hr could replace the BSER requirements and the respective AVO visit requirements. Doing so would increase the incentives to utilize new technology while simultaneously providing clearer and more quantifiable emission benefits than the AVO program offers.

Commenter (2284-Kairos) adds that, similarly, advanced screening techniques are effective at identifying things like unlit flares that are classified as malfunctions instead of being classified as fugitive emissions. That classification, however, is arbitrary and any advanced leak screening technology that can identify these types of malfunctions should be incentivized and those emission reductions should be incorporated in FEAST modeling.

Commenter (2340-Honeywell) noted that EPA explains in the preamble to the proposed supplemental rule that it used FEAST modeling to determine the screening frequencies and methane detection thresholds that would provide equivalent fugitive emissions reductions to the BSER methods. This resulted in the periodic screening matrices, which prescribe a survey frequency (and in some cases an annual OGI backstop) depending on the minimum detection threshold of the survey technology, with a maximum detection threshold of 30 kg/hr.

Commenter (2340-Honeywell) supports EPA's efforts to provide flexibility through the screening matrices to accommodate a variety of methane survey technologies that can meet varying detection sensitivity thresholds. Doing so will facilitate further development and deployment of advanced technologies for methane emissions monitoring. Honeywell recommends, however, that EPA provide even further flexibility based on modeling, where screening frequency and detection thresholds are inversely related at least within specified bounds (as the benefit of increasing frequency may be limited when detection thresholds are above the vast majority of emissions rates). Rather than prescribing a limited set of screening frequencies and detection thresholds, the final rule should allow the use of FEAST modeling to determine the screening frequency based on the minimum detection levels that the technology can provide.

Commenter (2340-Honeywell) notes that EPA has established, through FEAST modeling, that periodic screenings with a detection sensitivity of greater than 30 kg/hr cannot be considered equivalent to BSER at any screening frequency. As such, the final rule can maintain 30 kg/hr as the upper bound of the detection thresholds. Greater flexibility within that range, however, will further encourage and facilitate the adoption of advanced screening technologies.

Response II-5-103: EPA acknowledges the commenters' input. As discussed in Section XI.B.1 of the preamble of the rule, EPA conducted FEAST modeling of our model plants based on the most updated information available to ensure the matrix framework was equivalent to the BSER program.

Comment: Commenter (2448-Project Canary) states EPA's FEAST modeling assumes that all super-emitter events are persistent and not intermittent under the "duration" parameter in FEAST. However, the matrices have the potential to enable technologies that can be deployed to better detect large emission events that are persistent as well as intermittent. To represent super-emitter events more accurately and better reflect the potential of advanced technologies to detect them, the commenter urges EPA to ensure the assumptions for the final FEAST modeling reflect the best available data including any information regarding the intermittent nature of some super-emitters. EPA can rely on additional peer-reviewed studies submitted in comments that corroborate EPA's already cited studies as well as any studies published and peer-reviewed in the future.

Response II-5-104: We assumed all the large events were part of the sources covered by the group of fugitive emission sources. We recognize that some "super-emitter" events may be short-term events related to sources like blowdowns. However, we assumed that fugitive emission components would likely have more sustained emissions. Therefore, we modeled the fugitive emission component releases as persistent.

Comment : Commenter (2284-Kairos) notes EPA's FEAST modeling compares alternative technology performance to OGI strictly on the basis of fugitive emission reductions. While the thought process here is understandable, it makes for an inaccurate comparison. Advanced screening programs, particularly when conducted on a more frequent basis than quarterly inspections, have the ability to replace AVO surveys of dubious efficacy with more rigorous, quantitative measurement. There is undoubtedly an emissions benefit to using state-of-the-art leak detection equipment over AVO techniques with little quantifiable benefit.

Commenter (2284-Kairos) recommends EPA should further incentivize advanced screening technology by allowing those techniques to replace periodic AVO visits and capture the emission reductions of using technology-based measurement in lieu of AVO in modeling. EPA modeling should also account for screening technology's ability to create indirect benefits, like rapidly identifying malfunctions that may not be classified as fugitive emissions. Advanced screening programs should satisfy AVO requirements and flare monitoring requirements as well as fugitive emissions monitoring, to further incentivize the use of more rigorous advanced technologies.

Response II-5-105: EPA acknowledges the input from the commenter, As discussed in Section XI.B.1 of the preamble of the rule, EPA conducted FEAST modeling of our model plants based on the most updated information available to ensure the matrix framework was equivalent to the BSER program.

In regard to flare monitoring, when a periodic screening identifies an emission and owner or operator is required to conduct a follow-up inspection to confirm the location of those emissions,

unless the technology used has sufficient spatial resolution to confirm the precise location of the emissions. See discussion in section XI.B.1 of the preamble of the final rule.

Comment: Commenters (2333-LongPath, 2428-API) believe EPA's current model overestimates the effectiveness of AVO and OGI. Commenter (2428-API) notes in EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies for periodic screening and for continuous monitoring.

Commenter (2333-LongPath) understands that, in the EPA's FEAST model simulations, AVO is parameterized as having 100% probability of detection for emission rates of roughly 245 g/hr (0.245 kg/hr). The EPA states that "while there is a lack of information on the emissions reductions achieved through an AVO inspection, the EPA is confident that specific indications of potential leaks (*e.g.*, open valves or thief hatches) would be obvious to any operator...". The commenter respectfully suggests that field studies or data be used to justify the parameterization of a 100% probability, particularly for such small emission sizes.

Commenter (2428-API) says that for example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (*e.g.*, potential for H<sub>2</sub>S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.<sup>51</sup> A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies.

Commenter (2333-LongPath) has many documented case studies in which AVO inspections failed to detect very large emissions, despite, in some cases, being deployed to find the root cause. For example, emissions in exceedance of 100 kg/hr that were caught by the commenter and diagnosed with SCADA data or OGI imagery, but which AVO inspections failed to detect or identify [Images of leak in commenter's attachment]. AVO inspections may suited for liquids leaks, or very specific instances in which a physical issue with the site is visually evident (*e.g.*, open thief hatch), but AVO inspections may not be reliable for the broader array of fugitive emissions causes.

Response II-5-106: In the proposed rule, we have a combination of OVA, OGI, and super-emitter response program, so we conclude that the rule as proposed (and finalized) would address the case indicated by the commenter.

Comment: Commenter (2421-Teledyne FLIR, LLC (Teledyne)) provides input on EPA's solicitation of comment on the use of LDAR effectiveness models in the development of the

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<sup>51</sup> Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285.

requirements for the alternative screening approach, specifically on the appropriateness of the inputs and assumptions used in the EPA's FEAST modeling simulations. It is challenging to accept that a technology that has a minimum detection threshold of  $\leq 1$  kg/hr used on a quarterly basis plus an annual OGI inspection would be equivalent to using a technology that has a minimum detection threshold of 17 g/hr, as defined in Appendix K of this docket, used at a quarterly interval without the additional annual inspection. OGI used quarterly with a minimum detection threshold that is 58 times better would be much superior to a periodic screening technology of the same defined timeframe as described in Table 20. This comparison leads to uncertainty and the appropriate use of the defined modeling simulations that may be developed specifically to encourage alternative technologies that are less sensitive than existing BSER requirements.

Response II-5-107: We only proposed use of Appendix K for natural gas processing plants. The OGI methods specified for use at production facilities has a much higher allowable minimum detection threshold and does not require two separate views of each component. We consider the modeled detection curve used in the equivalency matrix is reasonable portrayal of the effectiveness of OGI as required by the fugitive emissions program.

Comment: Commenter (2202-Texas Oil and Gas Association (TXOGA)) believes the modeling assumptions should be adjusted to ensure the comparison baseline for advanced technologies is realistic.

Commenter (2202-TXOGA) states technology advances are happening on more than an incremental scale and the environment will benefit from rules that allow deployment without regulatory changes being required. EPA's regulations should facilitate such changes to the maximum extent practicable. And a key element of that is being realistic about what the baseline technology is actually achieving when making the equivalence determination. EPA's overall approach of marrying frequency with detection thresholds seeks to match the frequency of monitoring to the level of accuracy of a technology. While this concept makes sense, it is important that EPA not be so conservative in its assumptions that it results in dampening the effectiveness of the alternative technology program.

The commenter is concerned that the level of stringency in the model will make it such that the new technologies will have to be better than BSER in order to be deployed. The commenter encourages EPA to make more reasonable assumptions in its model inputs, *e.g.*, with respect to windspeed, so that experience can be gained through deployment. The market penetration and deployment of these technologies will allow them to improve and actually end up raising the bar in terms of emissions performance. And that ultimately is the goal of this program. Indeed, the NSPS program has always had an underlying technology-forcing aim. In practice, however, when NSPS regulations have been written prescriptively, the regulations have gotten in the way of technology advancement. This is why the commenter (2202-TXOGA) is gratified that EPA is considering these issues and incorporating them in the regulations at this time.

Commenter (2202-TXOGA) supports the matrix approach for its simplicity, but it requests that EPA reevaluate the modeling assumptions that OGI/AVO are 100 percent effective. The commenter believes that this assumption does not align with real-world experience and, when

modeling equivalence with OGI, places unrealistic leak detection performance expectations on the alternative technologies.

Commenter (2202-TXOGA) continues, other steps EPA could take to ensure that alternative technologies and periodic monitoring result in net benefits equivalent to traditional OGI include revising Table 20 to explain the science behind why a bimonthly frequency of <2 kg/hr and <10 kg/hr (if an annual OGI survey is completed) are equivalent. EPA could also demonstrate why, under the minimum detection threshold of <4 kg/hr, monthly monitoring can be bimonthly if the owner/operator completes an annual OGI survey per the <10 kg/hr requirements.<sup>52</sup> At bottom, a final rule should refine the survey matrices in a manner that would better reflect minimum screening frequencies and detection thresholds to incentivize adoption of alternative technologies and foster technology innovation.

Commenter (2202-TXOGA) adds due to the large discrepancies that can occur with mass conversion; EPA should not rely solely on the ability to determine a mass emission rate (kg/hr) when assessing alternative leak detection technologies. EPA should also allow alternative leak detection technologies to use a background concentration and increase from that background level as a means to provide an action level for leak detection. The conversion of a detected concentration of methane to a mass emission rate (*e.g.*, kg/hr) is an added step in estimation that requires site-specific operational data or information that only the operator can provide. There can be a large discrepancy in the mass conversion. Alternative leak detection technologies can also identify a background concentration of molecules and base action levels on an increase from that background level. This can be a reliable method of detecting and responding to leaks in real time and does not present some of the challenges encountered with mass conversion based on operator data and calculations.

Response II-5-108: While we agree that the assumptions were required when modeling the effectiveness of different programs using FEAST, we maintain that the assumptions used are reasonable and provide a reasonable approach for assessing the equivalency of different monitoring programs.

Comment: Commenter (2284-Kairos) states that EPA should also consider how OGI follow-up surveys are separately parameterized for FEAST modeling relative to quarterly or annual OGI that is conducted independently of an airborne survey detection. In our experience, follow-up surveys using OGI at sites with known aerial detections are generally more effective at identifying emissions due to the suspected presence of a likely large source of emissions and location information provided by the aerial survey data. For this reason, follow-up OGI surveys should retain a spatial coverage parameter of 100%.

Commenter (2284-Kairos) states EPA would also need to consider how to define spatial resolution and source accuracy as metrics for alternative technologies—which is extremely difficult. For example, a minimum pixel size requirement might not have any bearing on spatial resolution. To meet a pixel size standard, a technology developer could simply take a big pixel and divide it into four pixels and all four would still have the same value. Alternatively, a measurement system may generate data which is not saved into a gridded space, such as an

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<sup>52</sup> Id.

airborne sniffer system, and therefore be fundamentally incompatible with a “pixel size” specification. EPA should avoid trying to get too prescriptive in spatial resolution guidance because it has the potential to forestall development of effective technology that does not meet some narrow, dated technology standard.

Commenter (2284-Kairos) argues if EPA moves away from requiring ground follow-up for some remote screening technologies but not others, it will need to carefully consider what impacts that has on the equivalency determinations it reached through FEAST modeling. Removing some ground inspection requirements but not others would likely require redoing FEAST modeling to properly understand the impacts on equivalency between programs.

Response II-5-109: We modeled all aerial surveys as site-wide survey and used the cumulative emissions from the site to trigger the OGI ground survey. Including spatial resolution into the model would require a well-pad site to be broken into numerous sub-sites, requiring assumptions on the number of fugitive components per sub-site, requiring a myriad of additional assumptions. While we understand that some technologies may have higher spatial resolution, that may not necessarily mean that they will find more leaks. For example, if a high spatial resolution detection method has a detection level of 1 kg/hr and there are two different leaks of 0.5 kg/hr at the site but spatially separate, the aerial survey as modeled would have deployed a ground crew (site total at or above 1 kg/hr) whereas the spatially resolute detection method would not have detected emissions. For the purposes of the generalized matrix approach, we maintain that the assumptions used are reasonable and provide a reasonable approach for assessing the equivalency of different monitoring programs.

Comment: Commenter (2414-Carbon Mapper/RMI) provides recommendations to the proposed matrix as well as assumptions used in FEAST modeling. The commenter believes the current proposal contains critical holes rooted in flawed assumptions in the FEAST modeling that underpins it. To address these concerns, the commenter provides evidence-based recommendations supported by empirical studies and a report conducted by Highwood Emissions Management commissioned by the authors (Appendix A). The commenter urges an expansion of the screening alternatives to leverage all technologies available to reduce emissions, specifically to:

- Recommendation 1: Expand matrix to include a Minimum Screening Frequency of “Weekly + Annual OGI” with a Minimum Detection Threshold of 100 kg/hr.
- Recommendation 2: Review and consider revising assumptions used in FEAST modeling for the Supplemental Proposal, including the assumed detection limits for OGI and AVO surveys, parameterization of spatial and temporal coverage, and leak generation rates, all of which can impact simulation results - particularly regarding intermittent high emission events.

Commenter (2414-Carbon Mapper/RMI) notes the EPA proposal states, “technologies with a minimum detection threshold above 30 kg/hr could not be deemed equivalent to the proposed fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc at any screening survey frequency.” The implications for this proposal, as written, are such that satellite technologies and some aircraft remote-sensing technologies will not be available as approved



alternative screening methods. To the commenter's knowledge, no satellites currently operational nor those expected for launch in the next few years and only a few currently operating airborne systems are capable of meeting a 30 kg/hr minimum detection threshold of screening at 90 percent probability of detection.

Commenter (2414-Carbon Mapper/RMI) states despite not meeting the currently proposed maximum detection threshold, many satellite and high-altitude aircraft remote-sensing technologies are uniquely capable of spotting intermittent super-emitters thanks to a combination of broader spatial coverage and higher frequency sampling. This means that, in practice, these technologies can provide operators across many U.S. oil and gas production regions maximum flexibility and affordability as part of LDAR regimes. In some instances, these technologies are already being deployed voluntarily by operators seeking to go "above and beyond" required practices.

Commenter (2414-Carbon Mapper/RMI) generally supports the use of equivalency modeling such as FEAST and other rigorous models to determine the matrices. However, as acknowledged by EPA, the inputs and assumptions used in any model are critical in determining equivalency between alternative screening and the standard fugitive emissions detection and repair program. In this case, the exclusion of an entire class of monitoring instruments capable of higher frequency monitoring is of primary concern and is a direct result of suboptimal assumptions in EPA's FEAST modeling. Specifically, there are concerns with the EPA's intermittency assumptions for super-emitters, inability to properly parameterize temporal and spatial coverage of conventional methods in FEAST, and unrealistic assumptions about AVO screening performance.

To address these concerns, Commenter (2414-Carbon Mapper/RMI) partnered with Highwood Emissions Management to conduct modeling with LDAR-Sim to test the sensitivity of EPA's FEAST modeling to key input assumptions and explore screening scenarios not explored by EPA. The Highwood analysis used LDAR-Sim to evaluate the relative mitigation performance of different screening scenarios for monitoring 2,000 sites in a virtual world over the course of one year. These simulations used the same emissions distribution EPA derived from the Cusworth *et al.* 2021 Permian study and other common assumptions in an attempt to replicate EPA's FEAST modeling while also evaluating different assumptions.<sup>53</sup> The Highwood analysis is most sensitive to the following parameters: leak production rate, leak rate distribution, minimum detection limit, spatial coverage, and sample frequency (temporal coverage). The full report, including inputs and results of the Highwood analysis, is provided in Appendix A of the commenter's letter.

Commenter (2414-Carbon Mapper/RMI) states industry, technology providers, and experts in LDAR simulation repeatedly bring into question key assumptions about AVO and OGI performance used in EPA's FEAST modeling. Overly optimistic parameterization of these two technologies has important ramifications for equivalency – when these parameters are adjusted,

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<sup>53</sup> Cusworth, D., et al., "Intermittency of Large Methane Emitters in the Permian Basin," Environ. Sci. Technol. Lett. 2021, 8, 7, 567–573, <https://doi.org/10.1021/acs.estlett.1c00173>

conventional screening programs display more modest mitigation potential. The commenter also has concerns with other assumptions used in EPA's FEAST modeling.

Commenter (2414-Carbon Mapper/RMI) highlights the following five significant issues in EPA's FEAST modeling assumptions (more details can be found in the commenter's letter):

1. Spatial coverage is not parameterized in EPA FEAST modeling.
2. Temporal Coverage is not parameterized in EPA's FEAST modeling.
3. AVO MDL assumed in EPA's FEAST modeling is likely unrealistically low.
4. OGI MDL assumed in EPA's FEAST modeling is likely unrealistically low.
5. Leak generation rate assumptions in EPA FEAST modeling may be too low.

Commenter (2414-Carbon Mapper/RMI) states the methane mitigation performance of all evaluated satellite programs, most importantly with detection threshold 100 kg/hr and weekly screening, is equivalent to or exceeds the performance of options currently allowed in EPA proposal.

Commenter (2414-Carbon Mapper/RMI) notes the Highwood simulations evaluated the performance of an annual OGI inspection plus three hypothetical LDAR screening programs compatible with MDL and sample frequencies of representative satellite and airborne remote-sensing systems: 30 kg/hr, monthly; 50 kg/hr, biweekly (14 day); and 100 kg/hr, weekly. All three programs achieve greater emissions mitigation than quarterly OGI parameterized using Highwood assumptions (Figure 2, P\_OGI4x\_Highwood) under the Cusworth distribution. This is due primarily to the impact of the improved spatial and temporal coverage capabilities of remote sensing satellites and aircraft.

Commenter (2414-Carbon Mapper/RMI) notes that while some existing and planned satellites and aircraft are capable of achieving methane MDLs at or below 30 kg/hr, that typically only occurs under a narrow range of environmental conditions and hence the commenter recommends a 100 kg/hr threshold, which is likely more achievable for more technology providers.

The Highwood simulation results lead the commenter to strongly encourage Recommendation #1 and Recommendation #2 as described above and envisioned in Table 1B. Unless EPA expands the matrices to include the 100 kg/hr threshold, most satellites and many airborne systems will be excluded as alternative methods and dramatically limit the potential for emissions mitigation. For example, a recent review paper by Jacob et al 2022 noted most current and planned methane-capable satellites have detection limits well above 30 kg/hr but only a few report the ability to achieve detection limits as low as 100 kg/hr.<sup>54</sup> Commenter (2414-Carbon Mapper/RMI) notes that while EPA's and Highwood's modeling both use the same Cusworth et al. emissions distribution from surveys of the high emission Permian Basin, recent studies combining field measurements and simulation such as that from Sherwin et al. 2023 indicate that other major oil and gas basins exhibit similar emissions distribution characteristics.<sup>55</sup> Specifically, the Sherwin *et*

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<sup>54</sup> See Table 3 in Jacob et al., *Atmos. Chem. Phys.*, 22, 9617–9646, 2022 <https://doi.org/10.5194/acp-22-9617-2022>.

<sup>55</sup> Sherwin, E., et al., 2023, "Quantifying oil and natural gas system emissions using one million aerial sites measurements," Figure 3, in review *Nature*, preprint: <https://doi.org/10.21203/rs.3.rs-2406848/v1>.

*al.* study indicates 40%-80% of total point-source emissions from the oil and gas sector exceed 100 kg/hr in the Permian, Barnett, Marcellus and San Joaquin basins. Additionally, cumulative distribution functions for point source emissions in those basins as well as the lower-emission Uinta and Denver-Julesburg basins do not display a large drop between 100 kg/hr and 30 kg/hr. Therefore, the commenter's recommended additions to the screening program would be equally effective in achieving similar methane reduction across most U.S. oil and gas producing basins.

Additionally, commenter (2414-Carbon Mapper/RMI) urges EPA to consider the influence that the design of its rulemaking will exert on a rapidly changing landscape: specifications in the final matrix will affect technology development for years to come. Moreover, the US approach to and inclusion of advanced technologies, namely satellites with global, high-frequency monitoring capabilities, have the chance to spur positive domestic impact beyond the sectoral scope of this rule (focused on onshore oil and gas production) and beyond our national borders. At this pivotal moment in time for climate mitigation, expanding the matrix per our recommendations would ensure that all technologies available for methane reduction remain eligible while not requiring operators to opt into these high-frequency screening programs. Finally, given that emissions data will continue to rapidly improve, the commenter encourages EPA to recognize the importance of having a regulatory process and expectation to update the screening protocols periodically over time.

Response II-5-110: Based on the modeling conducted, there is no frequency at which a 100 kg/hr detection limit would be equivalent to the required periodic OGI monitoring surveys. There are few sites that have emissions above 100 kg/hr, so at that detection limit, 99+ percent of sites would be projected to have significantly higher fugitive emission than the levels determined to be BSER.

Comment: Commenter (2353-CrownQuest Operating, LLC (CrownQuest)) asserts that EPA mistakenly assumes more is better and that if one survey is good, then two surveys are better, rather than acknowledging that all things have a diminishing return. The EPA should carefully evaluate when LDAR surveys can most economically reduce emissions rather than building an unrealistic model. The EPA requires more work to be done and assumes proportional benefits without getting a reduction in emissions. According to the commenter, The Environmental Partnership launched in 2017 and has acted to reduce emissions. The partnership collected operators' data and is not an estimated calculation based on a model. Since 2018, the partnership has surveyed over 340,000 sites, 1.23 million surveys, and over 750 million components. The average leak rate from companies participating in the partnership is 0.08%. Over 95 industry companies comprise the partnership, from operators to the midstream.

Commenter (2353-CrownQuest) notes that EPA's leak rate of 0.5-2% from the FEAST model is more than six times the observed leak rate from the industry's OGI survey. The Environmental Partnership's data collection and collaboration with operators and midstream companies should be the program the EPA relies on for emission reductions. The EPA should develop a BSER based on the universal successes of those widespread programs. EPA calculated emission reductions in the preamble seem to be consistent with the higher leak rates used in the FEAST model and not the industry leak rate or the EPA's OOOOa.

Commenter (2353-CrownQuest) says the EPA has accepted OGI imaging for OOOOa testing for years with a two-point demonstration standard for LDAR. The EPA is now setting a 16-point demonstration standard for new detection technologies, which is significantly more stringent than the OOOOa standard for OGI cameras. To date, there is no readily available data that the currently approved OGI camera technology meets the proposed OOOOb/c standards. The EPA should not create a new detection standard while exempting existing technology from meeting this standard.

Commenter (2353-CrownQuest) believes the EPA should be consistent with its standards for detection and not hold new technologies or methods to a higher standard than methods and technologies previously approved. Industry companies made inquiries to reputable LDAR camera suppliers regarding the testing of camera performance. The suppliers commented that they did not test the camera performance under the proposed conditions because the proposed rules are not yet approved. The suppliers reached out to a reliable third-party testing laboratory to take the test, but the testing lab said they could not prepare until the EPA finalizes the rule.

Response II-5-111: The commenter did not provide adequate data to assess the results of their monitoring surveys. If these monitoring events were conducted quarterly, then the annual leak rate would be 0.32% ( $0.08 \times 4$ ), which is close to the level used when determining BSER. We used leak rates from sites that were required to conduct quarterly monitoring to help inform our assumptions on the annual leak rates and we maintain that the assumptions we used to model the effectiveness of fugitive emission programs are reasonable.

Commenter (2298-Pioneer) supports EPA's proposed approach for utilizing FEAST model to estimate the emission reductions advanced technologies achieve. The inputs and assumptions used in the model are critical to "determine a matrix of survey frequencies and detection thresholds that would provide a demonstration of equivalency between the alternative screening and the standard fugitive emissions monitoring and repair program."<sup>56</sup> EPA cites recent aerial and satellite studies to conclude that "a primary advantage of more frequent screening with advanced technologies is to quickly identify large emission events (commonly referred to as 'super-emitters')" which may result from fugitive emissions or "other sources, such as unlit flares or process malfunctions."<sup>57</sup> Accordingly, EPA included process malfunctions in the equivalency assessment.

Commenter (2298-Pioneer) states EPA's use of peer reviewed studies to develop the matrix is reasonable recognizing the data that is available today.<sup>58</sup> However, the commenter encourages EPA to consider any additional updates and refinements for the Final Rule to ensure it reflects our up to date understanding of emissions and technology opportunities and constraints.

Commenter (2298-Pioneer) states in addition to supplementing EPA's assumptions and inputs for FEAST with any changes (i.e. changing the requirement for mandatory 001 follow-up for alternative technology as discussed above and thus revising this input in FEAST) or additional

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<sup>56</sup> 87 Fed. Reg. 74 742.

<sup>57</sup> 87 Fed. Reg. 74742.

<sup>58</sup> d. For example, EPA developed its super-emitter distribution based on an aerial study by Cusworth, Daniel, et al. 2 June 2021, <https://pubs.acs.org/cloi/10.1021/acs.estlett.1c00173>.

studies submitted as part of comments or released before the Final Rule, the commenter recommends that EPA make clear in the Final Rule that it will periodically update the matrix by updating the FEAST modeling and inputs as additional data becomes available<sup>59</sup> (e.g., every two years). Given that emissions data will continue to rapidly improve as operators use advanced technology and as EPA implements the Inflation Reduction Act funding for methane detection, it will be important to have a regulatory process and expectation that EPA will refine the matrix over time. By providing this expectation, stakeholders will have notice of this opportunity and can participate in the regulatory process. Additionally, specifying the timing for updates will also provide clarity on when EPA will need to receive proposed updates to studies and versions of modeling software to enable the agency to rely on such new information in the periodic update.

Response II-5-112: We understand that the FEAST modeling assumptions can significantly alter the equivalency determinations. We used assumptions that were reasonable considering the myriad of differences in the advanced technologies. Allowing facilities or service technology providers to make significant changes in those modeling assumptions would often result in significantly altered modeling assumptions to “demonstrate” equivalency even in cases where there may not be reasonable equivalency. We maintain that the assumptions we used to model the effectiveness of fugitive emission programs are reasonable and we are maintaining the matrix approach are proposed.

### ***5.8.8 Handheld Alternatives to OGI***

Comment: Commenter (2419-Xplorobot) believes that it is essential that the language of the new NSPS OOOOb and EG OOOOc call for periodic screening using not only OGI cameras but also equivalent hand-held technologies that can provide component-level localization of the emissions and their quantification using physics-based measurements. The current language of the EPA regulations results in operators viewing Teledyne-FLIR OGI cameras or similar hardware provided by other vendors as the only technology that can meet the requirement to “make visible emissions that may otherwise be invisible to the naked eye”. There are novel technologies other than OGI cameras that can achieve the desired goal, including, but not limited, to the technology developed by the commenter. The commenter’s technology uses Tunable Diode Laser Absorption Spectroscopy (TDLAS) paired with advanced Computer Vision for precise localization of each TDLAS measurement relative to the equipment inspected in order to create a 3-dimensional map of methane concentration and a quantitative estimation of the emissions rate. The commenter suggests that the language of the revised 40 CFR Part 60 be revised to state “OGI camera or equivalent hand-held component-level detection and quantification technologies” in place of simply “OGI camera” to remove the bias to one specific technology and to encourage innovation and new technology development for hand-held sensors.

Commenter (2419-Xplorobot) respectfully requests that EPA issues a clarification for subparts OOOO and OOOOa to include not only OGI cameras but also equivalent hand-held component-level technologies that can “make visible emissions that may otherwise be invisible to the naked eye” and also quantify the methane concentration and the emissions rate.

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<sup>59</sup> This is consistent with the Draft Science Advisory Board's January 4, 2023, recommendations. [add link]

Commenter (2419-Xplorobot) respectfully suggests that the Agency encourage the use of quantitative physics-based measurements for component-level hand-held devices such that the subjectivity of the inspection or impact of training or dwelling time is eliminated. Such quantification methods include but are not limited to the use of TDLAS sensors paired with advanced Computer Vision that provide precise localization of each TDLAS measurement relative to the equipment inspected to create a 3-dimensional map of methane concentration and a quantitative estimation of the emissions rate.

Response II-5-113: EPA acknowledges the comment, EPA could consider alternatives for OGI follow-up using other technologies through the alternative test method delegation in §60.8(b), so long as there is a defined method/procedure for use and that method/procedure yields the same sensitivity as OGI.

Comment: Commenter (2226-Thermo Fisher) recommends using more acute handheld measurement devices (like Thermo Fisher's Toxic Vapor Analyzer 2020) in conjunction with the OGI to ensure emissions are appropriately accounted for. Additionally, the EPA should consider continuous emissions monitoring technology for abandoned and unplugged wells of high risk for gas leaks.

Response II-5-114: EPA Method 21 is an allowed alternative to OGI in the rule, while we do not specify instruments to use with Method 21, EPA acknowledges that the instrument included in comment would meet the requirements for Method 21, in this rule.

Comment: Commenter (2185-NYSC) states the EPA should consider requiring the use of additional technologies, such as handheld natural gas detectors, to back up the use of AVO monitoring to ensure that leaks are accurately detected at this class of sites.

Response II-5-115: EPA acknowledges the commenters input; EPA is finalizing the options allowed in the proposed rule.

### ***5.8.9 Weather/Seasonal Considerations***

Comment: Commenters (2405-Bridger, 2428-API) believe the periodic screening alternative approach should be flexible to address seasonal environmental challenges.

Commenter (2405-Bridger) notes that seasonal environmental conditions need to be considered for emissions monitoring because they can adversely affect methane detection performance. A challenge for many remote sensing technologies is ground snow cover, which reduces light reflectivity at wavelengths used for methane detection. This means that a weaker signal is available for methane sensing. In regions that have snow cover for part of the year, operators using remote sensing technologies for emissions monitoring may need to anticipate periods of time when there is a reduced probability of detecting emissions. Other seasonal environmental challenges may also need to be considered. High winds disperse methane plumes, meaning that lower concentrations of methane are available for detection. Meanwhile, the performance of remote sensing technologies using solar radiation may be degraded during overcast periods. The EPA already provided provisions in the Proposed Rule for seasonal environmental challenges for

OGI surveys, *i.e.*, “quarterly monitoring may be waived when temperatures are below 0°F for two of three consecutive calendar months of a quarterly monitoring period”.

Commenter (2405-Bridger) observes that the EPA does not specify whether different periodic screening detection tiers can be applied within a single LDAR monitoring plan during different time periods. Doing so would help operators in regions with seasonal environmental challenges to achieve regulatory compliance within their LDAR monitoring programs. In this scenario, for intervals when environmental challenges reduce emission detection probability, operators could switch to higher frequency monitoring (*i.e.*, a different monitoring tier). The commenter recommends that the EPA provides clear language in the preamble and regulatory text describing the option to switch between detection sensitivity and frequency tiers of the periodic screening matrix on a quarterly basis. By way of example, for screening complex facilities, during three quarters of the year, a certain technology may be capable of achieving sufficient detection sensitivity to meet the most stringent tier (1 kg hr<sup>-1</sup>, 90% PoD). But during the fourth quarter, snow cover may only allow 2 kg hr<sup>-1</sup>. During that quarter, bimonthly (*i.e.*, more frequent) scans could be used to achieve compliance.

Commenter (2405-Bridger) states that the proposed rule includes an exemption for OGI surveys during extreme cold weather. To develop rigorously performance-based methane monitoring requirements, where exemptions exist for one monitoring approach, these same exemptions should extend to the other monitoring approaches. This results in the cold weather exemption also applying to the periodic screening and continuous monitoring alternative approaches. To remove ambiguity, the commenter asks the EPA to clarify whether “below 0 degrees Fahrenheit (°F)” refers to average temperature or some other metric, and how this is to be determined. In addition, because emissions screening during fugitive emissions monitoring can also be used for compliance verification of zero-emission standards, then compliance verification of these numerical standards should also not be required during the impacted quarter.

Commenter (2405-Bridger) says that to account for seasonal methane detection sensitivity limitations, they urge the EPA to make it clear that detection tiers may be selected on a quarterly basis, and to make emissions screening exemptions consistent across monitoring approaches. Commenter (2428-API) provides some examples:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

Commenter (2428-API) believes the alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA’s proposed requirements. Flexibility

in applying alternate screening technologies should include provisions that use of a different technology than originally planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

Response II-5-116: EPA recognizes that environmental factors do affect the performance of alternative methane detection technology. EPA has provided flexibility in the final rule to replace a periodic screening survey using alternative methane detection technology with OGI at any time. EPA has also revised the final rule to allow flexibility in selecting your periodic screening technology as explained in Section X.B.1 and XI.B.1 of the preamble of the rule.

Comment: Commenter (2284-Kairos) explains that wind speed impacts the sensitivity of a remote sensing detection of methane, and therefore a measure of wind speed at a site to ensure good performance is needed. The commenter made the following points:

- In situ wind measurements at all sites are not feasible. Therefore, the commenter must use models or interpret the available wind data from a sparse network of meteorological stations.
- Given the known limitations and expected error associated with modeled or off-site wind estimates (*e.g.*, closest weather station), operating envelope thresholds for alternative technology cannot be implemented based on a single, rigidly defined wind speed value.
- Rather, an estimate of prevailing conditions, characterized by a group of measurements, should be the basis for defining an alternative technology operating envelope.
- EPA should develop guidance on how to define operating envelopes and use the available data sources to verify survey conditions adhere to the defined operating envelope.

Commenter (2284-Kairos) continues, so what wind data is available to EPA? It is technically infeasible for EPA to require alternative technologies to use site-level (in situ) wind readings or wind readings at the exact moment of survey for several critical reasons:

- Investing in wind sensors for the approximately 1 million wells in the US is both technically challenging (to install, maintain, calibrate, and replace, as well as hindered by data transmission limitations common to remote operating regions) as well as a significant economic burden.
- Consistency cannot be guaranteed between operators, wind measurement technologies, and installation locations.
- Integrating data from in situ weather monitoring systems operated and maintained by oil and gas operators with systems operated by alternative technology providers likely presents a logistical burden for both parties.
- Most critically, it's simply not necessary to build and maintain a network of 1 million new wind sensors nationwide to set operating envelopes.

Therefore, a wind estimate for a site must be interpolated, modeled, or extrapolated based on data collected off-site. Across an oil and gas basin, there are no other feasible options for field-wide wind measurements other than this type of estimation. However, using off-site data sources requires caution. Extending measurements across spatial and temporal dimensions will always generate an expected range of error relative to a ground truth, and therefore fixating on a rigid



threshold (as defined by a single value) for wind speed measurements would be highly problematic.

Any public standard that relies on interpolated, modeled, or extrapolated data should not rely on a single wind speed value, which provides rigid precision without any guarantee of accuracy. Instead, the public standard should define operating envelopes based on a group of measurements, or “prevailing conditions,” across an appropriate temporal window.

Commenter (2284-Kairos) presents an analysis of two public weather station networks to illustrate why a prevailing conditions approach is the most robust way to work with extrapolated data. The commenter selected one network with more stations (thus greater spatial coverage in several basins of interest) and another with high-frequency data (thus greater temporal coverage).

*Wider spatial network:* Collects meteorological data used by NOAA’s High Resolution Rapid Refresh (HRRR) weather forecasting model.

*High frequency network:* Collects hourly or sub-hourly data for US Meteorological Terminal Aviation Routine weather reports (METAR), generally located at airports.

Commenter (2284-Kairos) compared wellsite location data, sourced from DrillingInfo, to station locations in order to understand their proximity, and also examined the frequency of data measurements. The commenter’s results are presented in Table 2 of their comment [Available weather station data for two networks (HRRR and METAR) across multiple US oil and gas basins] for several basins across the country. The commenter finds that the vast majority of production sites in several high-producing basins, including the Permian, Anadarko, San Juan, Haynesville, and Eagle Ford, are greater than 10 miles away from the nearest weather station. Furthermore, the availability of high frequency measurements (hourly or sub-hourly) is extremely low in these basins.

Commenter (2284-Kairos) states using the Permian and the HRRR network as a further example, the commenter finds that there are only 133 HRRR weather stations across the entire 60,000 square mile basin. A full 60% of wells (greater than 100 thousand wells in total) are more than 10 miles away from a weather station. Moreover, only 28 stations provide at least hourly measurements. That means that for the 61,761 square mile Permian, just 28 stations provide even hourly wind data, or one station for every 2,026 square miles, which is an area larger than the entire state of Delaware.

Commenter (2284-Kairos) adds, HRRR stations are published with an 8-hour lag, so even datasets that are collected at hourly intervals are not available for assessing operating envelopes until well after a survey is concluded. This creates a significant logistical burden for alternative technology providers, as conditions may not be confirmed until the next day. The commenter’s results demonstrate that estimating a local wind speed value for most sites will require both spatial and temporal interpolation across significant distances and time steps. Because a single estimate will be inherently imprecise, a prevailing conditions approach that incorporates several measurements, e.g., by calculating a mean, will provide a more representative view.

Commenter (2284-Kairos) states commercial data models are generated with proprietary algorithms and sometimes at non-specified spatial and/or temporal timesteps. There is minimal assessment of error available for public review, which is problematic. So, what does this mean for establishing alternative technology operating envelopes?

- Wind speed impacts the sensitivity of methane detection systems, and therefore a measure of wind speed to ensure acceptable performance is needed.
- In situ wind measurements at all sites are not feasible for remote sensing programs; therefore, an interpolated, modeled, or extended measurement based on off-site data must be an acceptable source for wind data.
- Given the known limitations and expected error associated with an interpolated or off-site wind estimate, operating envelope thresholds for alternative technology cannot be implemented based on a single, rigidly defined wind speed value.
- Rather, an estimate of prevailing conditions, characterized by a group of measurements and/or model outputs, should be the basis for defining an alternative technology operating envelope.

Commenter (2284-Kairos) continues, if EPA were to take a position that under no circumstances could an aerial technology be used to survey a site when a single wind speed value, extracted from a distant wind station or interpolated wind product, showed a small exceedance of the operating envelope, it would severely disadvantage alternative technologies while providing de minimis environmental benefit.

In practice, such guidance would require commenter (2284-Kairos) to invalidate a site measurement based on one measurement from a meteorological sensor located 10 or more miles away and measured 45 minutes prior to the survey. Clearly, the wind measurement described in this example does not necessarily reflect conditions at the location and time of the survey, and so it should be treated with appropriate caution. The chilling effect on all alternative technologies stemming from this approach would be substantial, as well as unnecessary for ensuring good performance.

Commenter (2284-Kairos) states instead, EPA should require advanced screening technologies to determine adherence to operating envelopes using prevailing conditions. Prevailing conditions could be defined using a collection of measurements, *e.g.*, by calculating their average. This approach facilitates validation of appropriate operating conditions for alternative technologies while minimizing noise and the risks associated with rigidly precise, yet inaccurate, data collected offsite.

Commenter (2284-Kairos) notes given EPA's generous approach to factoring wind speed into OGI sensitivity in its FEAST modeling and operating envelope, it is appropriate for EPA to accommodate advanced screening technology by allowing the operating envelope to be defined by prevailing winds, as it provides the required data for ensuring sensitivity to a reasonable standard given the limits on wind data that are outside the control of alternative technology providers.

Commenter (2284-Kairos) states EPA should calculate prevailing conditions as an average of data across multiple stations and an appropriate time window. This is a preliminary recommendation and should be viewed as “directionally correct” but not robustly tested yet. Advanced screening programs could validate conditions for a given survey on a given day by thresholding the maximum wind speed as the mean calculated across some prescribed number of stations (*e.g.*, 3) and a window of time adequate for sparse temporal reporting (*e.g.*, 8, 12, or 24 hours). This would provide a reasonable estimate of wind speed to guarantee performance.

Commenter (2284-Kairos) provide an example, using 3 wind stations and a single, 8-hour averaging window:

- Wind station one (readings every 1 hour): [6,5,3,4,6,5,7,4] (winds in miles per hour)
- Wind station two (readings every 4 hours): [4,5,3]
- Wind station three (readings every 2 hours): [4,2,6,3]
- Average wind speed: 4.5
- Max wind speed for calculating conditions: 4.5 mph

Commenter (2284-Kairos) states using the example shown above, the technology provider would need to demonstrate that its system meets the prescribed sensitivity requirement at up to 4.5 mph. EPA may ultimately find that some alternative calculation, such as a median value, is more representative. By relying on multiple sources of wind data to quantify the prevailing operating conditions, EPA will provide guidance on suitable operating envelopes that satisfy the larger program goals. Ultimately, EPA’s aim is to reduce as much methane as cost-effectively as possible, not resolve wind speed conditions beyond a shadow of a doubt.

Commenter (2284-Kairos) concludes with two recommendations for the EPA:

1. EPA should allow alternative technologies to establish operating envelopes based on a prevailing conditions approach quantified by daily (8, 12, or 24 hour) wind speed averages (or similar method) and develop guidance on how to define operating envelopes using available wind data sources.
2. For advanced screening methods, in situ wind data is unavailable or infeasible to collect. The commenter recommends that EPA consider publicly available sources (such as HRRR model stations, METAR stations) and third-party modeling tools as possible options to determine wind conditions. EPA should consider the significant logistical challenges alternative technology providers face when estimating wind speed at a surveyed site, including spatial and temporal sparsity, data lag, imprecision, and lack of ground validation.

Since wind speed data is an area of emerging importance, commenter (2284-Kairos) suggests EPA consider developing stand-alone guidance on how alternative technologies address wind speed impacts on operating envelopes through separate guidance that can be updated periodically outside of the formal rulemaking process.

Response II-5-117: EPA recognizes the commenters input; EPA has expanded on the required information an alternative methane detection technology provider must submit to the EPA when requesting approval. These are detailed in Section X.B.3 of the preamble of the final rule.

EPA considers meteorology to be a critical component to any assumed rate base emission detection, however we leave it to the providers to determine what works best for their solution.

## 5.9 Continuous Monitoring

### 5.9.1 General Comments

Comment: Commenters (2226-Thermo Fisher, 2235-SLB, 2325-Aclima, 2333-LongPath, 2363-CEMC, 2409-BP America Inc. (BP), 2428-API, 2433-EDF *et al.*, 2462-Private Citizen) strongly support the proposed broadening of the requirement for monitoring to include continuous monitoring and specific rules for recording data and maintaining equipment. Continuous monitoring technology has the potential to shift the paradigm in methane detection and achieve significant methane emission reductions.

Commenter (2363-CEMC) strongly supports the EPA’s inclusion of provisions allowing operators to use advanced methane detection technologies for compliance purposes. However, the EPA has proposed to find that—at least at this time—periodic surveying with OGI and Method 21 is BSER that has been “adequately demonstrated.” The commenter indicates that there is substantial evidence that these systems fail to detect significant volumes of intermittent leaks that occur in between surveys, including leaks that qualify as “super-emitter” events. Additionally, as a recent study focusing on detection limits for OGI cameras indicates, “[o]verall detection rates from the camera-surveyor system are substantially lower than the detection rates estimated from studies focused solely on the camera performance...”<sup>60</sup> Further, the OGI surveyor experience level can also have a large impact on OGI use efficacy; “Study results indicate that OGI survey experience significantly impacts leak detection rate: Surveyors from operators/contractors who had surveyed more than 551 sites prior to testing detected 1.7 (1.5–1.8) times more leaks than surveyors who had completed fewer surveys.”<sup>61</sup>

Commenter (2363-CEMC) emphasizes that incentivizing operators to use alternative test methods is critical to the agency’s ultimate goals for this rulemaking and for the impending rules for the Methane Emission Reduction Program (MERP) and Subpart W established in §60113 of the Inflation Reduction Act (IRA). The MERP relies on methane intensity, which is why Congress also mandated in §60113 that the EPA update Subpart W to require “accurate” and “empirical” data. Advanced technologies, such as continuous monitoring solutions, provide the greatest temporal resolution, resulting in the most representative emissions profile and methane

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<sup>60</sup> Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Environmental Science & Technology* 2020 54 (18), 11506–11514 <https://pubs.acs.org/doi/full/10.1021/acs.est.0c01285>.

<sup>61</sup> Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Environmental Science & Technology* 2020, 54, 18, 11506–11514. <https://pubs.acs.org/doi/full/10.1021/acs.est.0c01285>.

intensity of an oil and gas facility. These new requirements are simply not achievable without advanced technologies and continuous monitoring.

Commenter (2363-CEMC) adds that the proposal will:

Generate additional reductions of methane emissions and additional reductions of emissions of ozone-causing VOCs.

1. Increasing deployment of continuous monitoring systems will help the EPA develop a more accurate methane emissions inventory for the entire oil and gas sector.
2. Increased deployment of advanced monitoring technologies across a variety of well sites will help develop valuable information for the EPA about the performance of different configurations of these technologies in different settings, which will provide EPA with information to develop specific guidance on the proper operation of these systems.
3. EPA investment in continuous monitoring system infrastructure will ensure short-, medium- and especially long-term effective emission measurement and reductions. As super-emitter events are reduced in the future with improved satellite and aerial technologies, unintentional basin emissions will be increasingly dominated by smaller sources, which are more effectively discovered through continuous monitoring systems.

Commenter (2409-BP) urges EPA to consider the environmental and operational benefits of continuous monitoring in the broadest possible terms, so as not to limit innovation or diminish the impact of these technologies.

Commenter (2433-EDF *et al.*) supports EPA's proposal to allow continuous monitoring technologies as an alternative to periodic screening based on long- and short-term emissions rate thresholds that would trigger corrective action paired with monitoring plan requirements.

Commenter (2428-API) supports EPA's inclusion of continuous monitoring in §60.5398b(c) and believes there is great potential in the use of continuous/near-continuous methane monitoring technologies.

Commenter (2325-Aclima) proposes that Internet-connected sensor-based solutions exist at a high level of technical readiness today, allowing for continuous monitoring that is widely distributed, cost effective, and remote. This screening approach should be considered for fugitive emissions monitoring. The commenter urges the EPA to require continuous monitoring at each well site, both large and small. Costs would be in the hundreds of dollars per year, per well — a fraction of the cost of OGI surveys.

Commenter (2325-Aclima) says that as it is now feasible, EPA should expand monitoring requirements to require continuous monitoring and repair of leaks from wells with low production rates. In aggregate, these smaller wells can be a significant source of methane emissions and continuous monitoring is needed to ensure that leaks at these sources are detected and stopped. Distributed sensor technology makes this both possible and cost effective.

Commenter (2325-Aclima) adds that these sensors can be networked and connected to cloud analytic systems, providing real-time monitoring of leaks across large portfolios. This gives well owners a comprehensive and timely picture of assets in the field. Further, advances in big data processing and algorithmic analysis filter out false positives and provide early detection of super-emitting events. It is also possible to aggregate data into powerful cloud-based geospatial tools that can cover wide geographies and can serve entire consortiums of O&G customers, achieving economies of scale, network effects, and reduced costs.

Commenter (2462-Private Citizen) argues advances in technology make this equipment available and affordable. For example, the commenter's college students had access to a wide range of monitoring units and software to interpret trends; certainly, industry has even more.

Commenter (2333-LongPath) states that EPA has identified a clean solution that would result in very low overall emissions. The commenter respectfully suggests to the EPA, however, that the continuous monitoring provisions, as written, would be non-competitive with the periodic screening matrix or OGI screening program. The feedback the commenter has received from the dozens of operators who use them for continuous monitoring is that they would not use continuous monitoring under these provisions, because the response levels are not aligned with the requirements for OGI or periodic screening.

Commenter (2333-LongPath) states that given the profound potential for greater emissions reductions under more frequent screenings afforded by continuous monitoring, coupled with the myriad ways in which even the most careful regulations can easily inadvertently disincentivize continuous monitors, the commenter advocates for incentivization for operator use of continuous monitoring. One such incentive could be through extending corrective action deadlines and maintaining no requirement for OGI follow up.

Response II-5-118: EPA acknowledges the commenters' input. The role of continuous monitoring has been revised in the final rule as explained in Section X.B.2 and XI.B.2 of the preamble of the final rule. This approach relies on a performance base approach, as is the way in which any technology with the ability to meet the QA requirements of the rule could be included.

Comment: Commenter (2207-Private Citizen) provides detailed information on Project Astra, which is testing the effectiveness of a shared network of fixed methane emission monitors in the Permian Basin oil and gas production region in West Texas. The network is monitoring emissions from approximately 50 production sites. The Permian basin was chosen for this demonstration because it is the largest oil and gas production region (by volume of production) in the United States, because the region has simple topography and strong and persistent winds and because the close proximity oil and gas production sites in the Permian Basin enhances the advantages of a shared network of sensors.

Commenter (2207-Private Citizen) summarizes the main findings from Project Astra as follows (more detailed information can be found in the commenter's letter):

- Four sensor systems (Aeris, Canary, Quanta3 and Scientific Aviation) demonstrated sufficient precision to identify emissions of 5-10 kg/hr under the meteorological

conditions found in the Permian Basin, had one minute or better temporal resolution, and had data capture rates >80%, during 9 months of testing.

- For the conditions in the Permian Basin, simulations indicate that less than one continuous monitor per site is capable of consistently detecting emissions in the range of 5-10 kg/hr within one week of the onset of emissions, for both continuous and intermittent emission sources.
- Continuous monitoring networks can detect long duration (>1 day) emissions within an hour to a few days, even with just a single sensor deployed per site, under the meteorological conditions found in the Permian Basin.
- While continuous monitoring networks will not detect all short duration (<1 day) events, the number of undetected events can be estimated, based on dispersion modeling and the numbers of events of various durations that are detected.
- The emission reduction effectiveness of continuous monitoring systems coupled with OGI screening, can be included in the equivalency matrix defined in the Supplemental Proposal.
- Use of continuous emission monitors to identify and quickly respond to very large emission events can reduce the required frequency of OGI surveys, while maintaining a targeted level of emission reductions, for regions with large emission events.

Response II-5-119: EPA acknowledges the commenters' input.

Comment: While Commenter (2409-BP) appreciates EPA's effort in this Proposal to create a pathway for continuous monitoring, the commenter is concerned that the supplemental proposal may be too narrow and overly prescriptive, and that it does not sufficiently facilitate nor incentivize the adoption of continuous monitoring technology. EPA should establish a technology-neutral framework that allows for multiple types of continuous monitoring systems, rather than implicitly single out a handful of the technologies available today and provide a flexible pathway for demonstrating that a particular system meets the regulatory criteria for continuous monitoring as an alternative to the BSER.

Response II-5-120: EPA acknowledges the commenters' input. The framework in the final rule will indeed be technology neutral in that any technology capable of meeting specified QA requirements could be used as detailed in Section X.B.2 of the preamble of the rule.

Comment: Commenter (2333-LongPath) suggests that continuous monitoring with valid mass emission rate data be incentivized as an effective method for verification of repaired leaks. The commenter provides the following example, in which continuous monitoring data was uniquely able to accurately verify repair. A survey program, whether with ground based OGI, remote periodic screening, or AVO, would not have correctly verified or validated the repairs in this case study.

Commenter (2333-LongPath) identified higher-than-normal emission rates (using the Baseline + Action Level approach proposed in these comments). The operator conducted a visual inspection of the site and discovered a broken sight glass. Following that repair, emissions initially subsided, giving the impression of a verified repair. However, several days after the repair verification, emissions went up again. This time, a pressure relief valve (PRV) on a stock tank

was identified as malfunctioning and a repair was made. Again, following this action, emissions were temporarily reduced, such that a traditional repair verification would have again given the green light. However, intermittent emissions then persisted, driving the operator to visit the site one last time and make four additional repairs, including identifying and ameliorating the true root cause of the issue. This example demonstrates the unique capability of continuous monitoring for 1) effective and complete root cause identification of leaks and process malfunctions, and 2) high confidence validation and verification of successful repair.

Response II-5-121: EPA acknowledges the commenters' input. The work practice associated with continuous monitoring approach is designed with flexibility in mind and to avoid prescriptive find and fix provisions in the fugitive emission programs. This work practice better considers the intermittency of some leaks and puts the onus on owner or operator to determine the best way to keep their emissions below the action-level.

Comment: Commenter (2348-EWTC) states that continuous monitoring systems that do not quantify emissions provide value in aiding to understand where events are occurring and may be used with operational data to provide root cause of intermittent events.

Response II-5-122: EPA acknowledges the commenters' input.

Comment: Commenter (2283-Endeavor) supports EPA's proposal to allow operators to use a broader range of alternative technologies as such flexibility will spur continued innovation within the oil and gas sector. Because technology in this area is likely to outpace any future revisions to EPA's regulations, EPA should not codify a limited set of methods that operators can use to monitor fugitive emissions. Instead, EPA should develop standards and criteria and allow any technology or method that can meet that standard. EPA should also include a non-exclusive list of current technologies that would meet the standard so that operators know for certain that they can rely on those technologies. The commenter specifically requests that EPA include aerial flyovers as a monitoring option, as well as remote monitoring devices such as SOOFIE fixed continuous monitoring devices. In the commenter's experience, these methods of fugitive emissions monitoring have proven effective and cost-effective for remote sites. Endeavor also recognizes that the best method of detection can depend on the unique location and nature of each well site, and therefore encourages EPA to provide flexibility for operators to select the best method for their particular facilities.

Response II-5-123: EPA acknowledges the commenters' input. Technology QA and other qualifying requirements are detailed in the final rule and allow for increasingly improving and emerging technology to play a role in this area.

### ***5.9.2 Quantification***

Comment: Commenter (2428-API) indicates that currently available continuous/near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended, the commenter believes.



According to Commenter (2428-API), current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional “CEMS”. These monitors are “high frequency” monitors and not necessarily “continuous” in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

Commenter (2428-API) states the proposed framework should not be limited by a technology’s ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system’s ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually “measures” a rate. The “quantification” capability is not derived from the underlying “smoke alarm” sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Response II-5-124: For the purpose of this rule, EPA has defined continuous as a reading every 12-hours as it relates to the continuous monitoring provisions to the rule. As stated above in this chapter, an owner or operator can use technology that operates continuously for periodic screening approach but is not subject to the 12-hour requirement.

Comment: Therefore, commenter (2428-API) believes these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

Commenter (2428-API) argues continuous/near-continuous monitors should be evaluated against BSER, which is quarterly OGI. As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of “fenceline” type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as “the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block.” This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

Response II-5-125: The continuous monitoring provision is directly comparable to the potential methane emission reduction as quarterly OGI, however instead of the find and fix paradigm of a

traditional fugitive monitoring program, instead we have incorporated a separate work practice that will yield the same level of emission reduction by keeping maintaining the site-level emission (+ background) below an action-level.

Comment: Commenter (2333-LongPath) believes the EPA’s intention in specifying “valid quantification” was to distinguish accurate from inaccurate mass emission rate estimation (*e.g.*, kg/hr). Many solutions provide quantification data with unstated or unproven accuracy. It is important that accuracy be validated in extensive 3rd-party blind testing. It is important for EPA to distinguish between validated and non-validated emission rate quantification capabilities, given the differences between the accuracy stated by individual vendors and the accuracy defined in a recent continuous monitoring blind testing review.<sup>62</sup> The commenter has published blind validation of mass emission rate estimation results.<sup>63</sup> For example, the commenter’s blind test (at METEC) average quantification error of single-source emissions is 9.1%, for emission rates below 1 kg/hr. Blind field testing with operators shows no bias in reported emissions at rates up to and above 200 kg/hr. The commenter’s blind testing clearly shows the ability to average to the correct emission rate value over time.

Commenter (2333-LongPath) suggests the following definition of “Valid Quantification”: “The emission rate quantification accuracy of the solution has been validated in 3rd-party blind testing to meet a defined standard of performance.”

Response II-5-126: EPA acknowledges the commenters’ input. The required information for technology providers should submit for an alternative test method for methane detection technology are detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule.

Comment: Commenter (2333-LongPath) suggests that EPA define a standard for accuracy in mass emission rate estimation that emphasizes the importance of correctly prioritizing the magnitudes of emission rates that will be required under the final rule. For example, a 200% error in quantification of a 0.1 kg/hr leak is a relatively minor error compared with a 200% error in quantification of a 10 kg/hr emission rate. The metric should thus be built around ensuring that the technology solution be capable of consistently distinguishing emission rates that are above or below the Action Level and Baseline.

Commenter (2333-LongPath) is aware that some groups may define “valid quantification” simply as a verified data point, that is, a data point that has passed quality assurance protocols and came from a technology solution that provides data in units of mass emission rate (*e.g.*, kg/hr). The commenter presumes that any data point used for compliance be required to be “valid” and therefore interpret EPA’s use of this word to mean something more.

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<sup>62</sup> Bell, C., Ilonze, C., Duggan, A., Zimmerle, D., Performance of continuous emission monitoring solutions under single-blind controlled testing protocol, preprint: <https://chemrxiv.org/engage/chemrxiv/article/details/638cd2ff14d92d3587a07c46>.

<sup>63</sup> Alden, C., et al. Single-blind quantification of natural gas leaks from 1 km distance using frequency combs, ES&T 2019, 53: <https://doi.org/10.1021/acs.est.8b06259>.

Response II-5-127: EPA acknowledges the commenters' input. EPA has defined the requirements for continuous monitors in in Section X.B.2 and XI.B.2 of the preamble of the final rule.

Comment: Commenter (2333-LongPath) urges the EPA to define the word “valid” in the requirement for continuous monitors to mean: The emission rate quantification accuracy of the solution has been validated in 3rd-party blind testing to meet a defined standard of performance built to suit the continuous monitoring requirements.

Response II-5-128: EPA acknowledges the commenters' input. EPA has defined the requirements for continuous monitors in in Section X.B.2 and XI.B.2 of the preamble of the final rule.

### ***5.9.3 Downtime***

Comment: Commenter (2409-BP America Inc.) argue EPA should amend 40 CFR § 60.5398b(c)(1)(iii)(B) and § 60.5398b(c)(1)(iii)(C) to establish a more reasonable standard for operational downtime and inoperability that better accounts for the networked approach that many continuous monitoring systems utilize, whereby multiple sensors are deployed at each facility. For example, multiple sensors may be deployed for one fugitive emissions component; if one sensor stops working, that does not mean that the monitoring system for the component is down or “out-of-control,” and much less so for the broader network of sensors throughout the site.

Commenter (2409-BP America Inc.) states creating a reasonable standard for inoperability is critical because the supplemental proposal limits operational downtime to a rolling annual average of 10 percent. §60.5398b(c)(1)(iii)(A). Defining operational downtime as any time one sensor is inoperable in a network of multiple sensors will create an unreasonable standard for operators in the deployment of continuous monitoring technology and may disincentivize operators from deploying more sensors despite the fact that the use of more sensors provides greater coverage and accuracy. Instead, Commenter (2409-BP America Inc.) recommends that, for the purposes of this rule, EPA define operational downtime to mean that fewer than 75 percent of the sensors at the facility are functioning. Specifically, EPA should amend § 60.5398b(c)(1)(iii)(B) to define “operational downtime . . . as a period of time for which more than 25 percent of the monitors at the facility fail to collect or transmit data or are out-of-control.”

Commenter (2409-BP America Inc.) continues, EPA should similarly amend the definition of “out-of-control” to acknowledge that self-monitoring systems can provide data necessary to perform “ongoing quality assurance checks” without the need for constant human intervention. One of the advantages of advanced methane detection technology is to reduce the frequency of human intervention in the field for purposes of methane monitoring and detection, and thus to improve reliability, safety, and performance. As such, continuous monitoring systems can provide automated quality assurance mechanisms to ensure that the system is functioning properly and issue alerts when issues arise. Overreliance on human intervention for quality assurance is both inefficient and unduly burdensome on operators, and thereby discourages the

deployment of continuous monitoring systems. Commenter (2409-BP America Inc.) argues EPA should therefore amend § 60.5398b(c)(1)(iii)(C) to read: “A monitor is out-of-control if it fails ongoing quality assurance checks, as specified in the alternative test method approved under paragraph (d) of this section and which may include automated quality assurance checks performed by the monitoring system, or if the monitor output is outside of range.”

Commenter (2307-Qube Technologies Inc. (Qube)) believes that the proposed rules around mass quantification and downtime should be related. The EPA has proposed that the system must produce a mass quantification at a minimum of once every twelve hours. The commenter agrees that this approach is reasonable as most continuous monitoring technologies (the commenter’s included) are capable of producing mass quantifications rates at a much more granular level. The EPA has proposed that the continuous monitoring system must transmit quality assured data greater than 90 percent of the time on a 12-month rolling average. The commenter agrees that the 90% uptime target is reasonable however, the methodology used to calculate uptime isn’t described adequately. For downtime calculation methodology, the commenter proposes using the frequency of the mass quantification, currently defined as 12 hours, to determine the uptime. If the system produces a mass quantification rate in the 12-hour period, then the system is considered as being online.

Response II-5-129: EPA acknowledges the commenters’ input. EPA is maintaining the requirements downtime in the final rule as explained in Section X.B.2 and XI.B.2 of the preamble of the final rule.

EPA acknowledges the commenters’ concern about one of many sensors failing, however, sensors are one of several technology options and one which the commenter is not forced to use.

Comment: Commenter (2346-Encino) states that EPA’s proposed rules do account for intermittent and continuous monitoring. However, these rules do not reflect real-world applications where intermittent inspections take only a snapshot; a continuous-based optical monitoring device (like a handheld OGI in principle) can utilize a more advanced payload and technology package (*e.g.*, cooled detector array, advanced processing, system diagnostics, wireless communications), thereby adapting to environmental and operational flux. As such, remote operations will need to account for a grace period resulting from force majeure conditions. Within 24 hours after the condition has passed, and site is deemed safe (to return) would be appropriate. Otherwise, the survey will need to be restarted. Additionally, there should be an allowance (for the system) to provide time to achieve continuous monitoring system stability and operability once camera field of view (FOV) is tuned, network is stable, and data transfer is reliable.

Commenter (2346-Encino) adds, wireless connectivity uptime on camera systems may be limited for remote locations, and local imagery storage would be sufficient if captured for the minimal survey period. Connectivity is not required if the camera is functioning correctly and is capturing emission releases. A typical downtime may require up to four or more days a month and could result in exceeding the proposed downtime regulation. Accordingly, flexibility in downtime for remote locations is necessary. The commenter recommends including the hours required for CMS calibration, stability, and operability into uptime. Uptime includes all calibration tuning

until the FOV is tuned, network is stable, and data transfer is reliable. This practice will encourage proper camera operation and promote optimum detection capabilities with advanced methane technologies.

Commenter (2346-Encino) states a rule that allows testing to continue but has some values withdrawn from analysis due to meteorological data would allow for better detection of issues and reduce full recalibrations. One example of this is the general rule used by testing companies that if there is wind over 10 mph, then testing must be stopped and when restarted the testing device must be recalibrated.

Commenter (2346-Encino) notes similarly, if there was the ability to perform pre and post linearity testing to ensure system integrity of a monitoring system it would allow for fewer testing interruptions and calibrations. The fewer calibrations that must be performed, the less chance of human error occurring. Also, the definition of continuous monitoring should include any instrument that allows monitoring of a location for use over 24 hours and calibration at least every 14 days. Alternatively, alignment with EPA section 325(A/B) for VOC fence line monitoring could be appropriate.

Response II-5-130: EPA acknowledges the commenters' input. As explained elsewhere in the chapter, EPA is maintaining the definition of continuous monitors in the final rule and has clarified that continuous methane detection technology in the periodic screening approach. EPA has also provided these details in Section X.B and XI. B of the preamble of the final rule.

Comment: Commenter (2333-LongPath) sees no inherent problem with EPA's proposed downtime definitions, but strongly advocates for approaches that provide closer parity with BSER. The commenter believes that these types of details can be highly technology-specific and should therefore be considered in alternative method applications.

Commenter (2333-LongPath) argues if a monitor were down for a period of time equal to the BSER requirements for OGI frequency, it is more appropriate to specify that the operator begin to implement BSER OGI at the appropriate frequency until such time as the continuous monitoring can be reinstated. With that type of approach, EPA would not risk placing burdens on advanced technologies that far exceed the BSER OGI baseline of emissions reduction.

Commenter (2333-LongPath) further comments on the health checks defined in §60.5398b(c)(1), where it is required that continuous monitoring systems "must be confirmed for power and connectivity at least twice every six-hour block." The commenter finds this language to be overly prescriptive and redundant to the downtime specifications and suggest that it is better suited to be in an individual technology's alternative test method application.

Response II-5-131: EPA acknowledges the commenters' input.

Comment: Commenter (2177-Southern Ute) recommends, regarding operational downtime, to add a definition of 12-month rolling average. The commenter cites the following solicitation:

“The EPA is proposing that the operational downtime of the continuous monitoring system, or the time that any monitor fails to collect or transmit quality assured data, must be less than or equal to 10 percent on a 12-month rolling average, where the 12-month average is recalculated each month.”

The commenter believes the language used in §60.5398b(c)(1)(iii)(D) is not clear. The commenter also recommends that operational downtime should not exceed 10 percent during any 12-month rolling period. Downtime should be calculated monthly, in the commenter’s opinion.

Response II-5-132: EPA acknowledges the commenters’ input. EPA has also provided details on downtime in Section X.B.2 and XI.B.2 of the preamble of the final rule.

#### ***5.9.4 Fenceline/Within Fenceline***

Comment: Commenter (2428-API) generally supports EPA’s inclusion of continuous monitoring but believes the framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind. As written, EPA’s proposed requirements for continuous monitoring appear to be designed for fenceline technology. The commenter asks that EPA clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. The commenter fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today’s fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

Response II-5-133: EPA acknowledges the commenters’ input. The goal of the continuous monitoring provisions in the rule is to quantify an emission flux from a facility, EPA recognizes that could be developed many ways and the design of these systems is not limited to fenceline monitors.

Comment: Commenter (2340-Honeywell) believes that the action levels and measurement averaging periods for continuous monitoring should be flexible, and the detection thresholds should be based on the probability of detection rather than a prescribed minimum. The framework for establishing minimum detection thresholds and action levels for continuous monitoring should be flexible enough to incentivize the development and deployment of best-in-class technologies, which can be deployed inside the fenceline and in the heart of the operations and should reflect their real-world value and advantages over periodic screening in providing overall emissions reductions and insights into a variety of emission types, sizes, and root causes.

In that regard, commenter (2340-Honeywell) recommends that the final rule adopt a framework that allows for a flexible approach to both the action levels and emissions measurement averaging periods and prescribes a probability of detection of the requisite leak rates rather than a particular minimum detection sensitivity. A more flexible framework should include the ability

to set higher action levels than those proposed based on shorter measurement averaging periods (e.g., a 30 kg/hr action level with a 1-day averaging period) to better reflect the use case found to be most valuable by some operators deploying continuous monitoring systems today. Setting a minimum probability of detection rather than a minimum detection sensitivity (as currently proposed) would enhance both reliability and provide a more technology-agnostic approach. The final rule can allow for this flexibility providing for the use of modeling (e.g., plume modeling and FEAST modeling) to determine the action levels, measurement averaging periods, and minimum detection sensitivities that would provide equivalence to BSER and ensure reliable emissions measurements.

Commenter (2340-Honeywell) believes that the proposed framework for continuous monitoring technologies is too prescriptive and stringent and does not create an outcome-oriented and technology-neutral approach that reflects the value and use cases for continuous monitoring to incentivize their deployment. In particular, by setting prescribed action levels and measurement averaging periods (i.e., the 7- and 90-day measurement periods), the proposed rule excludes systems that can also provide equivalent emissions reductions to BSER or periodic screening by implementing corrective action based on shorter measurement periods for larger leaks. Moreover, the commenter does not believe that the proposed requirement that continuous monitoring systems be capable of measuring emissions at an “order of magnitude” lower (i.e., 1/10) than the proposed action levels (e.g., 0.12 kg/hr for the 1.2 kg/hr long-term action level for wellhead-only well sites) is justified. This requirement is overly prescriptive and appears to be technology-specific rather than outcome-based and technology-agnostic. The proposed parameters for continuous monitoring technology are based on the presumption that all such systems will be deployed on the fenceline of a facility. In the context of the commenter’s technology (and many others in the industry), however, sensors are placed at the heart of the operation, and therefore the ability to detect emissions from a source does not require the same degree of sensitivity as a system deployed on the fenceline.

Commenter (2340-Honeywell) believes that the stringency and prescriptive nature of the proposed framework for continuous monitoring (a) is unnecessary for providing effective emissions monitoring and reductions, (b) lacks parity with the standards established for alternative periodic screening, (c) will disincentivize the development and deployment of continuous monitoring technologies, and (d) is not based on accurate modeling of emissions events or assumptions about the use of such technologies. The commenter recommends that EPA amend the framework to allow for the flexibility (similar to the periodic screening matrices) to set a variety of action levels and corresponding measurement timeframes, which could range from a 1-day averaging period to the currently proposed 7-day and 90-day averaging periods, so long as equivalent emissions reductions can be demonstrated. Further, instead of prescribing a minimum detection sensitivity, adopt a more technology-neutral approach which specifies a probability of detection (e.g., 90%) of the requisite leak rate.

Commenter (2340-Honeywell) states the value of continuous monitoring technology is that it detects fugitive emission events from the moment they begin through the moment that they end or are remedied. Periodic surveys, by contrast, provide only a snapshot of emissions at that one moment in time; fugitive emissions events that occur between periodic surveys therefore may go undetected. Screening frequency is a key component in effectively reducing emissions through

leak detection and repair, as well as in developing an accurate emissions inventory. However, the minimum detection thresholds required for continuous monitoring technologies are far more stringent than those required for periodic screening surveys and place a much greater emphasis on detection sensitivity in a way that may downplay the benefits achieved (as discussed further below) from the significantly increased frequency of monitoring. Doing so may therefore disincentivize the development and deployment of continuous monitoring systems.

Commenter (2340-Honeywell) continues the proposed framework for alternative periodic screening provides two matrices that, depending on the type of facility, allow operators to select a frequency of screening based on the minimum detection capability of the screening technology. For well sites with major production and processing equipment, for example, those minimum detection thresholds range from (less than or equal to) 1 kg/hr through (less than or equal to) 30 kg/hr, and several detection thresholds (*e.g.*, 2 kg/hr and 4 kg/hr) do not require an annual OGI survey as a backstop. The technology must be capable of detecting that a leak is occurring at the prescribed mass emissions rate (in kg/hr) or greater in that moment in time, which would then trigger a follow-up investigation and repair response.

Commenter (2340-Honeywell) states by contrast, EPA proposes that, for a well site with major production and processing equipment, a continuous monitoring system must be capable of detecting, at a minimum, a mass emissions rate of 0.16 kg/hr, and quantifying the size of the leak at or above that rate each time it takes a reading. EPA's proposal does not provide the basis for the requirement that continuous monitoring technologies be capable of a minimum detection threshold of an order of magnitude lower than the action levels. This requirement, apparently derived from the NESHAP fenceline monitoring work practice, is not necessary to derive the benefit of continuous monitoring technologies in providing equivalent or greater emissions reductions compared to the BSER and/or the periodic screening alternative.

Commenter (2340-Honeywell) provides the example, if a component at a centralized production facility is leaking at 1.6 kg/hr (the long-term action level for such sites), an operator electing to conduct a periodic screening survey using technology that detects leaks at 2 kg/hr or greater will not catch this leak, as there is no OGI backstop for those screenings. However, a continuous monitoring system capable of quantifying leaks at only 1 kg/hr or greater will catch this leak—likely on a much quicker timeframe—and it would not have been necessary to detect the leak at 0.16 kg/hr to do so. As this example demonstrates, continuous monitoring technologies are capable of providing significant leak detection benefits to operators and on a much quicker timeframe than periodic surveys, either with handheld OGI cameras or through alternative periodic screening, but the proposed supplemental rule requires far more stringent detection capability for continuous monitoring systems than it does for periodic screening. Doing so may disincentivize the development and deployment of continuous monitoring and bias the use of advanced methane monitoring technology toward periodic screening as an alternative to BSER.

Commenter (2340-Honeywell) adds, at least one study has shown that the “real-world marginal effectiveness of methane mitigation through periodic surveys approaches zero as leak detection



sensitivity improves.”<sup>64</sup> In other words, there is a point of diminishing emission abatement effectiveness with using more sensitive instruments in LDAR programs. The most important goal of any LDAR program is to maximize emissions reductions; by potentially excluding the use of continuous monitoring technologies through strict action levels and minimum detection levels, however, the proposed rule would undermine the adoption of a highly effective means of emissions reductions that can provide significant advantages over periodic screening.

Commenter (2340-Honeywell) states EPA notes in the preamble that the proposed continuous monitoring framework is akin to the NESHAP fenceline monitoring work practice, and that the “order of magnitude” requirement is “to ensure that the continuous monitoring systems used in the alternative continuous monitoring approach are sensitive enough to trigger at the proposed action levels...” The commenter understands that this requirement is consistent with the qualifications for alternative testing technologies under the NESHAP fenceline monitoring work practice. That rule similarly requires a minimum detection sensitivity of an “order of magnitude” lower than the action level.<sup>65</sup> However, EPA has not provided further explanation or context as to why the detection sensitivity must be 1/10th of the action level to ensure that the system triggers at the action levels. The record for the NESHAP fenceline monitoring rulemaking does not provide much more explanation, either, beyond noting that the requirement was included “[i]n order to quantify the emissions detected...”<sup>66</sup> Neither explanation justifies the need for detection sensitivities to be 1/10th of the action levels in order to properly quantify emissions or trigger a corrective response at the action level. Further, the commenter’s methane monitoring systems (both Rebellion and Signal Scout) are deployed inside the fenceline and at the heart of the operations, and therefore do not require the same detection sensitivities as fenceline monitoring systems.

Commenter (2340-Honeywell) states the stated rationale—EPA’s concern that the instrument be sufficiently sensitive to trigger at the action level—stands in contrast with the periodic screening framework, which sets detection thresholds and a probability of detection, but does not require a minimum sensitivity of an order of magnitude below those thresholds. To the extent that EPA’s proposal to require continuous monitoring technologies to meet such low detection sensitivities is meant to account for potential variability in emissions levels below the action level, Honeywell notes that an operator will need to make assumptions regarding the level of emissions below the minimum detection sensitivity regardless of that sensitivity level, and there is no provision in the supplemental proposal what that assumption should be. For example, if there are no emissions detected (*i.e.*, a reading of 0 kg/hr for a 12-hour period), it is unclear whether the operator should assume that there were zero emissions or assume some baseline amount above zero. In any event, the operator could apply that same assumption regardless of the minimum detection sensitivity of its continuous monitoring system. If this is, in part, the basis for the “order of magnitude” requirement, this issue further highlights the higher standard to which EPA appears to be holding continuous monitoring as compared to periodic screening; not only are the

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<sup>64</sup> See Ravikumar AP, Wang J, McGuire M, Bell CS, Zimmerle D, Brandt AR. “Good versus Good Enough?” Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera, *Environ. Sci Technol.* 2018 52(4) 2368-2374, available at: <https://pubmed.ncbi.nlm.nih.gov/29351718>.

<sup>65</sup> See 40 CFR § 63.658(k)(3) (“The method detection limit must nominally be at least an order of magnitude below the action level, *i.e.*, 0.9 µg/m<sup>3</sup> benzene.”).

<sup>66</sup> EPA, “National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, Background Information for Final Amendments: Summary of Public Comments and Responses,” September 2015, p. 235.

minimum detection sensitivities for periodic screening higher, but the framework appears to assume that emission levels are zero if none are detected by the screening survey, as no corrective action would be triggered in that circumstance.

Commenter (2340-Honeywell) argues EPA's stated rationale therefore does not appear to support the need for detection sensitivities an "order of magnitude" below the action levels, and doing so lacks parity with the periodic screening alternative and is not necessary to ensure that continuous monitoring systems trigger corrective action at the requisite action levels.

Response II-5-134: EPA acknowledges the commenters' input. EPA has revised some details of the continuous monitoring approach as explained in Section X.B.2 and XI.B.2 in the preamble of the final rule.

Furthermore, the final rule maintains' EPA's technology agnostic and the performance of any methane detection technology approved for use must be supported through empirical measurements as explained in Section X.B.3 and XI.B.3 in the preamble of the final rule.

#### ***5.9.5 Action Levels and Baselines***

Comment: Commenter (2433-EDF *et al.*) notes EPA has proposed two action levels: a long-term action level (1.2-1.6 kg/hr based on rolling 90-day average) to limit emissions over time, and a short-term action level (15-21 kg/hr) to identify large leaks and malfunctions. Both would apply to all operators using continuous monitors and a root cause analysis and corrective action would be triggered when either action level is exceeded, requiring investigation and repairs within five days.

Response II-5-135: EPA acknowledges the commenters' support for the alternative continuous monitoring approach.

Comment: Commenters (2226-Thermo Fisher, 2235-SLB, 2428-API, 2433-EDF *et al.*) request that EPA lower the action levels proposed for continuous monitoring.

Commenter (2433-EDF *et al.*) states that given the broad variety of continuous monitoring systems and the multitude of factors that impact performance, EPA's approach is reasonably calculated to ensure equivalent emission reductions. The commenter urges EPA to consider lowering the short-term action level threshold or otherwise shortening the duration of the long-term action level. The commenter is concerned that the proposed framework could unnecessarily allow emissions to persist when they could be mitigated much sooner. EPA must also ensure sensor placement is adequate to detect emissions from all fugitive emissions components and any control devices, covers, or closed vent systems at the site. The commenter is aware of situations where continuous monitors have missed significant emissions events at sites due to sensors being placed too low. Because of these concerns, the commenter also urges EPA to require an OGI or AVO backstop at all sites opting for continuous monitoring consistent with our recommendations on the screening approaches.

Response II-5-136: EPA acknowledges the commenters' input; EPA has chosen to maintain the action levels for the continuous monitoring approach as they offer the equivalent emission reductions as the BSER.

Comment: Commenter (2433-EDF *et al.*) adds that certain continuous monitoring technologies may fit within the periodic screening framework, such as tower-based systems. The commenter therefore urges EPA to consider such technologies within that context during the alternative test method approval process. The commenter also recognizes that certain continuous monitoring systems may be highly effective but do not fit within the parameters set forth by EPA. The commenter urges EPA to evaluate those technologies through the technology approval process and through AMEL applications.

Commenter (2226-Thermo Fisher) provides feedback on whether there are different approaches that should be included for different types of continuous monitoring systems and how equivalency may be determined. It is the commenter's perspective that ground-based instrumentation networks are effective and that for any equivalency determination, the equipment should be tested in the field.

Response II-5-137: EPA acknowledges the commenters' input; EPA has revised the final rule to confirm that methane detection technology that operates more continuously could be used in the alternative periodic screening approach as detailed in Section X.B.1 and XI.B.1 of the preamble of the final rule.

Comment: Commenter (2226-Thermo Fisher) seeks clarification from EPA on the timescales, as the proposed rolling day averages may be long due to spikes and emission changes over time and may leave room for exposure risk. The commenter recommends the EPA consider shortening this requirement.

While commenter (2428-API) overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, the commenter has concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI. The commenter sees merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations. Regarding the proposed action levels, the commenter offers the following suggestions (more details on the specific recommendations can be found in the commenter's letter):

- Action levels should be based on detected emissions above an established baseline.
- The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.
- The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.

The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

Response II-5-138: EPA acknowledges the commenters' input; EPA did not take into account background emissions in the December 2022 proposal, based on comment, EPA has revised the final rule to account for background emissions sources of these facilities as detailed in Section X.B.2 and XI.B.2 of the preamble of the final rule.

Comment: Commenter (2235-SLB) says that the requirements for continuous monitors to have a detection level an order of magnitude below the action level and to produce a measurement at a set frequency of every 12 hours are difficult for most continuous monitors available today to satisfy. Typically, the performance of continuous monitors typically depends on environmental conditions such as wind and sunshine. Under favorable weather conditions, many continuous monitors can achieve performance better than those requirements, however performance may suffer under unfavorable weather conditions. Continuous monitors cannot guarantee that the environmental conditions will be favorable at least once every 12 hours. The objective for a measurement every 12 hours may have been to ensure reliability of ongoing monitoring. But continuous monitors exist that can evaluate suitability of site conditions for taking a measurement, thereby ensuring reliability of measurements without requiring a fixed measurement frequency of at least once every 12 hours. Additionally, a fixed frequency of measurements is unnecessary for continuous monitors to produce an accurate rolling average to determine if an emission is actionable (*i.e.*, if the rolling average emission rate exceeds the action threshold). The commenter says that, for example, measuring the 90 days rolling average would involve averaging 180 data points (under one measurement every 12 hours schema), while an equally accurate 90 day rolling average could be computed with fewer data points.

Commenter (2235-SLB) suggests as an alternative approach where EPA could accept continuous monitors with higher detection levels and/or less frequent measurements, if the systems made conservative estimates during instances in which the emission rate was too small to be measured or the environmental conditions were unfavorable for measurement. For example, when the emission rate was too low for a continuous monitor to measure, that emissions could be reported at a rate equal to the limit of detection for purposes of computing the rolling average. That procedure would be protective of the environment, because the reported emission would be at least as large as the actual emission. Moreover, it would be more consistent with the actual performance of continuous monitors because it would allow for continuous monitors with different detection limits, provided the detection limit for a continuous monitor fell below the action limit. Finally, it would incentivize innovation and deployment of more sensitive continuous monitors because more sensitive measurement would result in lower reported emissions by reducing the default limit of detection amount.

Commenter (2235-SLB) adds similarly, EPA could accept continuous monitors with variable durations between measurements—including less than once per 12 hours—if emissions during the period where environmental conditions were unfavorable for measurement were reported as the greater of the emission rate measured before and after the period (*i.e.*, the greater of the data

“bookends”) when environmental conditions were unfavorable for measurement. That procedure would be protective of the environment, because the reported emission would likely be at least as large as the actual emission (there is no reason to expect that emission rates are more likely to increase than to decrease during periods where environmental conditions are unfavorable for measurement). Moreover, it would be more consistent with the actual performance of continuous monitors because it would allow for continuous monitoring during periods where environmental conditions prevent measurement for as long as the rolling average duration associated with the highest action level is used. Finally, it would incentivize innovation and deployment of faster and more environmentally robust continuous monitors, because faster and more environmentally robust continuous monitors would result in less time where reported emissions would likely be at least as large as the actual emission.

Response II-5-139: EPA acknowledges the commenters’ input; EPA wrote the continuous program as a performance-based approach. We recognize that many current continuous solutions may not be able to meet the criteria in the approach however we recognize the value of the more continuous systems and EPA has revised the final rule to confirm that methane detection technology that operates more continuously could be used in the alternative periodic screening approach as detailed in Section X.B.1 and XI.B.1 of the preamble of the final rule.

Comment: Commenter (2235-SLB) states the supplemental provides guidance about how continuous monitors should be used with action levels corresponding to 7 day and 90 day rolling average windows. Many continuous monitors are used with the objective of finding leaks quickly and measuring a leak for 90 days before acting is not consistent with the best use of many continuous monitors. More effective continuous monitoring would occur with different durations of rolling average windows. To address this concern, SLB recommends that in addition to the prescribed 7 day and 90 day rolling average windows, requestors be allowed the option to submit FEAST models with different rolling average windows, customized to maximize the effectiveness of the continuous monitoring technology. Some continuous monitors are most effective when deployed using two rolling average windows, but other continuous monitors are most effective when deployed using a different number rolling average windows. In all cases, FEAST modeling would ensure that the action levels are set corresponding to the number and duration of rolling average windows to ensure that the resulting emissions reductions are equivalent to BSER.

Response II-5-140: EPA acknowledges the commenters’ input.

Comment: Commenter (2333-LongPath) expresses that site-level monitoring is important for many reasons. It is critically important that site-wide monitor responses are not tied to detection limits, but instead use Action Levels, and that those Action Levels be in addition to baseline (permitted) emission rates. That is, emissions in exceedance of the baseline emission rate plus Action Level require a response. The EPA suggests that site-level methane emissions pose as a surrogate for VOC emissions. The commenter is concerned that adding more requirements and expectations onto site-wide continuous monitoring technologies than has been added on to any other technologies further risks inadvertent disincentivizing of their use.

Commenter (2333-LongPath) respects the EPA's intention in applying the equivalency standard twice (as a long-term and as a short-term threshold). However, the commenter respectfully requests only one Action Level, the Short-Term Action Level, remain in the final rule. The commenter requests that the Long-Term Action Level be removed. The commenter justifies this request as follows, which additional details provided in their comment letter:

- The long-term limits do not achieve rapid find-and-fix, the primary value add of continuous monitoring.
- The use of two thresholds that accomplish the same end is redundant and unequal to the other screening alternatives, which do not require double counting.
- Requiring both a long-term and short-term limit adds unnecessary complexity for operators, which disincentivizes the use of continuous monitoring.
- The 90-day long-term threshold is more than an order of magnitude below the action levels proposed for periodic screening using other advanced technologies, despite a 60x increase in required frequency.
- There is no equivalent standard to the long-term (90-day) action level in either the OGI BSER or the periodic screening matrix.

Response II-5-141: EPA acknowledges the commenters' input. EPA disagrees that there is unnecessary complexity with the existence of two limits and suggest operators are capable of tracking both. Two levels provide more flexibility and minimizes methane emissions more than a single limit. All technology developers, including the commenter, can develop approaches to meet one or both limits.

Comment: Commenter (2333-LongPath) states as with all other alternative technologies, the action level for continuous monitoring should be calculated directly using the FEAST model to determine equivalent emissions reductions to the BSER program.

Commenter (2333-LongPath) states it is necessary to provide all technologies with parity in determining action or detection thresholds. As stated in the Methane Roundtable comment, with the support of representatives from all major stakeholder groups, "EPA should evaluate equivalency for both periodic screening technologies and continuous emission monitoring using the same sets of tools and FEAST modeling assumptions to ensure that the final rule is technology neutral." Therefore, the commenter respectfully requests that the same sets of FEAST modeling tools and parameters be used equally, across the board, for equivalency estimation.

Commenter (2333-LongPath) argues with the removal of the Long-Term Action Level for continuous monitoring, it will be relatively straightforward for EPA to employ the FEAST or LDAR-Sim models for calculating emissions reductions from the continuous program. The commenter offers the following suggested guidelines:

- Frequency: EPA has made clear that the frequency of scanning a site with continuous monitoring is at least every 12 hours. Therefore, EPA can model the frequency as 12-hourly. However, if the EPA chooses a 7-day averaging window for emissions detection, then the appropriate frequency to use will be 3.5 days, as leaks will be caught on average, within 3.5 days. Finally, as is discussed in our above comments, the phrase "frequency"

is unclear without being accompanied by a requirement for spatial coverage. Therefore, if the EPA chooses to define frequency and spatial coverage together (for example, all equipment must be scanned within a 7-day timeframe, on average), then the average time-to-detect would, again, be 3.5 days. In all scenarios, the most appropriate time-to-detect frequency parameter would be 3.5 days.

- Spatial Coverage: As is described above in our comments, it is critical to co-define temporal and spatial coverage. To accomplish this, EPA could pursue two options:
  - EPA could model the percent of the site that is scanned in each 12-hourly reading (or the spatial coverage), assuming each scan gives an equal chance for every equipment area to be covered (no systematic biases or blind spots).
  - EPA could require that all equipment on site be scanned within a certain maximum timeframe (say, 7 days).
- Minimum Detection Limit: With the removal of the Long-Term Action Level, the EPA can define the necessary minimum detection limit relative to the Short-Term Action Level that is determined by the FEAST model to be equivalent to BSER. Given that no detections below the Action Level are required to be mitigated, the minimum detection limit can be modeled as equal to the Action Level.
- Action Level: a key difference between EPA's use of the FEAST model for the periodic screening matrix is that the continuous monitoring provisions make use of an "Action Level" rather than a Minimum Detection Threshold. Therefore, regardless of what the minimum detection threshold is, the only emissions that are mitigated in the FEAST modeling of continuous monitors are those emissions for which the rate is above the defined action threshold.

Response II-5-142: EPA acknowledges the commenters' input. We have explained the criteria for the alternative continuous monitoring provisions in Section X.B.2 and XI.B.2 of the preamble of the final rule.

EPA has not integrated a modeling approach to determine action-levels and the action-levels are based on expected emission reductions of the BSER for the model plants. Owners or operators that wish to design a different alternative work practice should petition the Administrator for an Alternative Means of Emission Limitation (AMEL).

Comment: Commenter (2333-LongPath) states spatial coverage of measurements is a critical and often over-looked factor in how comprehensive a survey or continuous monitoring alternative technology solution is. As long as all potential emission sources are "seen" in a reasonable timeframe, then it is reasonable to assume comprehensive and full coverage. The potential for systematic spatial coverage biases, or "blind spots" should be a focus of EPA's specifications for all survey types: AVO, OGI, periodic screening technologies, and continuous monitoring technologies.

Response II-5-143: EPA acknowledges the commenter's input; it is understood that any alternative measurement approach must measure the entirety of a facility.

Comment: For continuous monitors, Commenter (2333-LongPath) suggests that EPA define the timeframe over which 100% (full) site coverage is required. The commenter suggests a

maximum of 7 days, on average (30 day running mean), for a monitoring solution to “see” all regulated emission sources on the pad.

Commenter (2333-LongPath) respectfully suggests that EPA carefully examine the parameter choices in the FEAST and LDAR-Sim models to investigate whether these models are capable of modeling systematic blind spots, and not blind spots that would move around randomly from equipment group to equipment group. Because of the potential for skewed emissions potential from different emission sources (*e.g.*, an unlit flare may have higher emission potential or likelihood than a malfunctioning pneumatic valve), it is important to investigate whether these models currently have the capability to simulate systematic blind spots or whether further development effort is needed.

Commenter (2333-LongPath) states in the EPA’s supplemental proposal, continuous monitors are required to have a detection limit one order of magnitude below the required Action Level. This choice results in required detection limits of 0.12 kg/hr for small well sites and 0.16 kg/hr for larger well sites and compressor stations. By comparison, survey technologies are required to have a 90% probability of detection of the target detection level.

Commenter (2333-LongPath) requests more information for why different standards were applied and ask whether it would be achievable for the EPA use equal treatment between technologies for the required minimum detection limit to achieve the requisite action levels. The commenter believes that a simple solution could be to specify that the 90% or 99% probability of detection of the technology must be equal to or less than the required Action Level. The 90% or 99% probability of detection could be determined, for example, following the methods described in the Bell et al., preprint.<sup>67</sup> The difference between an Action Level (no emissions below that limit need response) and a Detection Limit (anything detected, even below that limit, requires response) could justify the use of the 99% probability of detection limit.

Response II-5-144: EPA acknowledges the commenters’ input. All alternative to the BSER for fugitives and covers and closed vent systems are equivalent to the expected emission reductions from the BSER.

Comment: Commenter (2333-LongPath) states that in order not to inadvertently disincentivize continuous emission monitoring, the commenter describes the necessity of defining Action Levels as above Baseline emission rates the commenter notes that this method has been vetted and approved by the Colorado Department of Health and Environment (CDPHE) and EPA as part of LongPath Alt. AIMM in the state of Colorado). If this change is not made, and Action Levels alone define the site-wide emissions permissible for well sites and compressor stations, then continuous monitoring will be unusable by most any operator.

Commenter (2333-LongPath) states site-wide monitors measure both fugitive and permitted and normal process emissions. Permitted and process emissions may include compressor methane slippage, un-combusted methane from flares, permitted tank venting, pneumatic devices and

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<sup>67</sup> Figure 1 of Bell, C., Ilonze, C., Duggan, A., Zimmerle, D., Performance of continuous emission monitoring solutions under single-blind controlled testing protocol, preprint: <https://chemrxiv.org/engage/chemrxiv/article-details/638cd2ff14d92d3587a07c46>.



other sources. The commenter provides examples of permitted sources including engines, flares, and pneumatic valves, all which would have emissions higher than the proposed continuous monitoring sitewide emission rate limits. Even if the Long-Term Action Level is removed, the combination of two compressors and a flare would exceed even the proposed Short-Term Action Levels. Importantly, each of these sources can contribute to substantial temporal variability in the baseline emission rate. For example, methane slippage from compressors can vary depending on compressor operating setpoints and maintenance, and flaring intensity can vary significantly over time in correlation with production and oil-to-gas ratio fluctuations.<sup>68</sup>

Commenter (2333-LongPath) continues, bottom-up calculations are not sophisticated enough to accurately estimate the real-time magnitude and variability of baseline emissions. Baseline emission rates must therefore be measured; they cannot be calculated accurately in real-time from bottom-up principles. The consistently demonstrated mismatch between bottom-up and top-down calculations of emissions further supports this notion.

Commenter (2333-LongPath) notes the CDPHE, and the EPA evaluated and approved the use of non-visual quantitative continuous monitoring for 1) determination of baseline emission rates as well as 2) leak identification using baseline emission rates plus Action Levels. These details can be found in the commenter's recently approved Alt. AIMM application.<sup>69</sup> The commenter proved valid mass emission rate quantification of emissions and show that this capability allows the commenter to assess baseline emissions in a clean environment (with an OGI sweep at "startup" to ensure no fugitive emissions contribute to the baseline) and thereafter trigger alarms based on the baseline emission rate plus the defined Action Level for each monitored site type.

Response II-5-145: EPA acknowledges the commenters' input. As explained in Section X.B.2 and XI.B.2 in the preamble of the final rule, we have integrated a procedure for determining baseline emission and the action-levels are now considered to be above the baseline.

Comment: Commenter (2333-LongPath) states it is critical that continuous monitors capable of quantitative, full-site coverage be subject to Action Levels rather than Detection Limits. Therefore, FEAST can be parameterized so that 100% of leaks above the Action Level will be addressed by quantitative, full-site coverage continuous monitors.

Commenter (2333-LongPath) notes the EPA correctly identified in the Supplemental Rule's continuous monitoring provisions that Action Levels are the right response definition for continuous monitoring systems that are capable of quantification and full-site coverage. Specifically, if a site-wide continuous emissions monitor were subject to detection levels alone, then the EPA's requirement that any "detection" require action (regardless of whether it is above, at, or below the detection limit) would risk severely disincentivizing the use of continuous site-wide emissions monitors, given that their "on-the-ground" deployment typically leads to relatively low detection thresholds. For example, given the variable nature of permitted emissions, every permitted change in the operating conditions of the site (compressors on/off or flares on/off) could lead to an emission change that would require follow-up. This would make continuous monitors unusable for operators under this rule. Further, it could risk a "race-to-the-

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<sup>68</sup> These calculations were performed by Kuva in the commenter's discussions of the EPA supplemental proposal.

<sup>69</sup> <https://cdphe.colorado.gov/public-information/alternative-aimm-public-notice>.

bottom” for technology vendors to degrade their detection and quantification capabilities for fear of disincentivizing operator use. The commenter therefore recommends that EPA specify that the “detection levels” in the periodic screening matrix act as “Action Levels above baseline” for site-wide quantitative continuous monitoring technologies that participate in the matrix.

Commenter (2333-LongPath) states the below table is an adaptation of the technology class table shown above, which defines which solution types should be subject to the requirement that all detections require a response, and which solution types should be subject to the requirement that only detections above the Action Level + Baseline require a response (they suggest Action and Detection levels be equal, to ensure technology neutrality).

|                              | <b>Visual (plume-level) non-Visual (site-wide or source-level)</b>                                                                | <b>Visual (plume-level) non-Visual (site-wide or source-level)</b>                                                                                                                                                                                           |
|------------------------------|-----------------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Periodic Screening</b>    | Frequency and presence/absence of added OGI is based on technology’s Minimum Detection Limit.<br>All detections require response. | Frequency and presence/absence of added OGI is based on technology’s Minimum Detection Limit.<br>Detections equal to or greater than the Action Level + Baseline require response (Action Level is equal to Detection Level for this portion of the matrix). |
| <b>Continuous Monitoring</b> | Frequency and presence/absence of added OGI is based on technology’s Minimum Detection Limit.<br>All detections require response. | Frequency and presence/absence of added OGI is based on technology’s Minimum Detection Limit.<br>Detections equal to or greater than the Action Level + Baseline require response (Action Level is equal to Detection Level for this portion of the matrix)  |

Commenter (2333-LongPath) provides examples based on the EPA’s proposed screening survey matrix (see below) of a non-visual quantitative continuous monitor with a minimum detection threshold  $\leq 1$  kg/hr. Under the suggested considerations above, this solution could monitor small well sites with semi-annual screenings, with required response to emissions the baseline emission rate plus 1 kg/hr. The same solution could alternatively use tri-annual screenings with required response to emissions the baseline emission rate plus 2 kg/hr. For larger well sites and compressor stations, this continuous monitor with a minimum detection level  $\leq 1$  kg/hr could screen bimonthly, with required response to emissions the baseline emission rate plus 2 kg/hr. That same solution could monitor on a monthly basis with required response to emissions the baselines plus 4 kg/hr, and so on. These suggestions would be equally valid for any monitor capable of accurate (valid) quantification of total, site-wide mass emission rates. These

suggestions provide direct parity to the visual technology solutions for which the proposed periodic screening matrix was created.

Response II-5-146: EPA acknowledges the commenters' input. EPA has made revisions to the Alternative Continuous Monitoring Provisions as detailed in Sections X.B.2 and XI.B.2 of the preamble of the rule.

Comment: Commenter (2307-Qube) states the EPA has proposed using a site rate (kg/hr) versus a gas concentration from continuous monitoring systems to define when an emissions event requires follow-up action. The commenter agrees that using a site rate calculation is more effective than using a gas concentration as gas concentration is affected by the wind speed and distance from the source while a site rate calculation normalizes for these factors.

Commenter (2307-Qube) strongly believes that the proposed long-term action level poses a threat to the adoption of continuous monitoring rather than an incentive. A large number of facilities have been designed and are permitted to emit greater than 1.6 kg/h thus continuous monitoring would not be suitable for use at these facilities for regulatory purposes under the proposed framework. Therefore, the commenter suggests that the concept of a baseline be used to establish an emissions profile and action levels be incremental to that baseline. The baseline is meant to capture normal emissions from the facility while responses to the long-term and short-term action levels are meant to reduce fugitive emissions.

Commenter (2307-Qube) requests that the EPA consider the following process for establishing a baseline:

- Once the monitors have been installed and are fully operational a 90-day baseline period begins;
- 7 days after the baseline period begins, the operator performs a LDAR inspection using an EPA approved methodology;
- At the end of the 90-day period, the operator performs another LDAR inspection using an EPA approved methodology, to confirm that there are no fugitive components contributing to the baseline; and
- Use the average emissions mass quantification of the 90-day period to establish the baseline for the facility.

Commenter (2307-Qube) also requests that the EPA consider updating on an annual basis to capture changes to the baseline such as improved maintenance programs, production increases / declines, and equipment changes. The commenter suggests a streamlined approach to establishing a new baseline requiring a single LDAR inspection while using the average mass quantification data from a facility of the previous year. As a concept, the commenter believes that baselines are more representative if they are developed over a longer duration.

Commenter (2307-Qube) also believes that the long-term action level averaging time creates a number of unintended consequences. In deployments of continuous monitoring equipment to date, the commenter has observed a number of instances where short-duration, large-volume emission events are identified by the continuous monitoring system early in the deployment. The

owner of the site will respond to data generated by the continuous monitoring system and make repairs and other changes to the site that result in substantial reductions in emissions. Figure 1 below is an illustrative example of how a large spike in emissions rate, which is subsequently repaired quickly, can lead to a rolling average which exceeds the action level for a period of months:

[Figure 1 – Example site showing how operational events today impact the 90-day average.]

Response II-5-147: EPA acknowledges the commenters' input. As explained in Section X.B.2 and XI.B.2 in the preamble of the final rule, we have integrated a procedure for determining baseline emission and the action-levels are now considered to be above the baseline.

Comment: Commenter (2307-Qube) states the EPA has proposed that site Owner/Operators initiate a "root-cause analysis" to investigate if the short-term or long-term threshold is exceeded. The time delay between site-rate decreases and 90-day rolling average decreases can be troublesome as this can penalize operators for a considerable period of time. Operationally speaking, the emission events are in the past and corrective action has already taken place. Additionally, any emissions event whether it be maintenance, or a fugitive leak will contribute to increasing the rolling average. It isn't clear how operators would deal with subsequent increases to the rolling average when corrective action has already been taken for the initial event. Thus, the commenter suggests shorter averaging time periods which are consistent with how most operators are using the technology today.

Response II-5-148: EPA has revised the nomenclature around follow-up investigation from "root-cause" to "investigative analysis". The continuous program is designed to allow an owner or operator to conduct any repairs necessary during normal operation on their time frame to avoid any exceedance of an action-level, in an effort to avoid prescriptive find and fix requirements in the fugitive program.

Commenter (2307-Qube) concludes in terms of the absolute values proposed for the short and long-term action levels, it may be worth revisiting the modelling assumptions for equivalency. The model plant (4), which is representative of a gas gathering facility, will emit significantly less than an oil tank battery which typically has higher counts of storage vessels and fired equipment.

Response II-5-149: EPA acknowledges the commenters' input.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) believe action levels should be measured relative to a facility-specific baseline. Commenters support EPA's proposal in §60.5398b(c)(4)(i) to have both a short-term (7-day) and long-term (90-day) action level for continuous monitoring systems. This approach can address more significant, impactful fugitive releases, as well as smaller releases that can become significant if allowed to continue to vent unabated. However, as addressed in our comments above, the specific proposed action levels do not account for normal operations and associated "authorized" methane emissions rates. If EPA were to finalize the action levels as proposed, it would significantly discourage owners and

operators from adopting continuous monitoring systems, thereby eliminating significant opportunities for greater methane emissions reductions.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) propose an additional methodology by which an operator that wants to use a continuous monitoring system at a facility can first establish the baseline emissions level at the facility. The approach, as generally outlined below, could be established specifically within the regulatory language in this section, or an approach could be provided and approved within the Alternative Test Methods provision and technology approval process.

Commenters (2363-CEMC, 2448-Project Canary) state it is important to understand that certain ground-based, fixed continuous monitoring systems will calculate site-level methane emissions flux, inclusive of all methane emitting sources at a given facility, with source allocation providing a general equipment level location from where methane is emitted. However, these algorithms could represent methane emissions from a source that doesn't meet the definition of a fugitive emissions component, or a cover and closed vent system, such as methane slip from a compressor engine. The result could trigger an action level exceedance, while the emissions flux may be what is expected and part of normal operation, thereby disincentivizing the use of a continuous monitoring system.

For illustration of this point, methane emissions from intermittent pneumatic bleed devices using 40 CFR Part 98, Subpart W, Equation W-36 can be modified to calculate hourly methane emissions. Below is both the calculation as listed in Subpart W and its modified version (in kg/hr):

[Image of equation W-36 from 40 CFR Part 98, Subpart W]

A modified version with results in units of kg/hr is shown below:

$$\text{Mass Rate CH}_4 = \text{EF} \times \text{CH}_4 \text{ frac} \times \rho$$

Where:

Mass Rate CH<sub>4</sub> = CH<sub>4</sub> mass flow rate in kg/hr

EF = Intermittent Bleed Pneumatic Device emissions factor (Subpart W, Table W-1A) in scf/hr

CH<sub>4</sub> frac = mole fraction of CH<sub>4</sub> in gas stream

ρ = density of CH<sub>4</sub> (0.0192 kg/scf)

$$\text{Mass Rate CH}_4 = 13.5 \text{ scf/hr} \times 0.80 \text{ frac CH}_4 \times 0.0192 \text{ kg/scf}$$

$$\text{Mass Rate CH}_4 \text{ per intermittent bleed pneumatic device} = 0.21 \text{ kg/hr}$$

Response II-5-150: EPA acknowledges the commenters' input. As explained in Section X.B.2 and XI.B.2 in the preamble of the final rule, we have integrated a procedure for determining baseline emission and the action-levels are now considered to be above the baseline.

Comment: Commenters (2363-CEMC, 2448-Project Canary) state therefore, a well site with eight intermittent bleed pneumatic devices (putting aside any other authorized methane sources) would exceed the proposed action level of 1.6 kg/hr methane mass emissions rate on an ongoing basis. The commenters understand that the majority of multi-well sites are likely to be equipped

with more than eight intermittent bleed pneumatic devices, as well as other normally operating sources of methane emissions.

Response II-5-151: As explained in Section X.D and XI.D of the preamble of the rule, the final rule will result in the phasing out of the use of intermittent bleed pneumatics and therefore it is not a long-term consideration. Also, as explained in Section X.B.2 and XI.B.2 in the preamble of the final rule, we have integrated a procedure for determining site-level baseline emission to account for allowed process emissions and the action-levels are now considered to be above the baseline.

Comment: Commenters (2363-CEMC, 2448-Project Canary) argue this situation is likely to be exacerbated at larger locations, where more natural gas fired engines and other methane emitting sources are present. In fact, at least one continuous emission monitoring service provider, Project Canary, has performed a preliminary analysis of one customer's facilities where site-level methane flux is calculated and determined that roughly 30% of those locations exceeded the 1.6 kg/hr, 90-day rolling average action level during normal operations. Consider also that, under the proposed action levels, a lower emitting oil and gas well site could potentially have a more persistent, slightly higher volume leak of methane than a higher emitting well site and still not exceed an action level which would otherwise be triggered at the larger site. The commenter believes this could both disincentivize the use of continuous monitoring systems and inadvertently allow for more fugitive leaks from smaller well sites.

Specifically, commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) suggest the following methodology for setting a baseline methane emissions rate for each wellhead-only and well site opting to use an approved continuous monitoring technology under §60.5398b(c)(1). Action levels would then be measured against this baseline. The methodology would work as follows:

- The owner or operator first installs and commences the operation of the EPA-approved continuous monitoring system.
- When the continuous monitoring system is fully operational, a 60-day baselining period begins. During this period, the owner or operator will perform periodic, full-site LDAR inspections using an EPA-approved method, such as OGI cameras or Method 21. These inspections shall occur within 7 days of the date the continuous monitoring system is fully operational, with an additional inspection at 30 days and 60 days. The additional OGI or Method 21 inspections will verify that the site is operating without unintentional methane emissions from fugitive components, thereby establishing the site's individual baseline emissions without leaks.
- The baseline will then be determined by averaging the valid methane mass emissions rates, determined once every twelve-hour block, during the baselining period.
- Short-term and long-term action levels will then be set as the values established in §60.5398b(c)(4)(i) of this section added to the average value obtained during the 60-day baseline period.
- The determined baseline methane mass emissions rate remains valid unless and until annual actual or potential emissions from the location change by more than 5%, at which time another baselining period should be initiated.

- The owner or operator may update the baseline voluntarily at any time.

Response II-5-152: EPA acknowledges the commenters' input. As explained in Section X.B.2 and XI.B.2 in the preamble of the final rule, we have integrated a procedure for determining baseline emission and the action-levels are now considered to be above the baseline.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) provide comments on the potential use of methane intensity or production rates in the development and use as action levels for continuous monitoring systems.<sup>70</sup> The commenters' general understanding of production accounting within the oil and gas industry is that there can often be a significant lag in determining the actual production volumes that flow through a given location, sometimes up to 60 days or more. Changes to production levels reported through prior period adjustments over a month in arrears have the potential to sway intensity numbers on a given location in an unpredictable manner potentially resulting in missed action level exceedances. The commenters recommend the EPA not implement an action level determination utilizing either methane intensity or facility production.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) recognize that methane intensity is the primary metric for the IRA MERP. However, the methane intensity metric in the MERP is calculated on an annual basis. It is reasonable to expect that an operator will be able to determine and report its annual production. And it is clear to us that Congress intended that there should be increasingly rigorous detection and quantification of methane emissions in the oil and gas sector. For example, the MERP requires EPA to levy the waste emissions charge on a *per-ton* methane intensity basis, which is not possible without highly accurate measurement of both emissions and throughput at affected facilities.

Response II-5-153: EPA acknowledges the commenters' input. EPA has chosen not to incorporate "methane intensity" into any of the standard if this final rule.

Comment: Commenter (2333-Longpath) appreciates EPA's interest in using percentage of intensity as a metric, given the vast differences in absolute rates of site-wide emissions across different asset types and basins in the US. Unfortunately, it is not yet clear how operators could use a single, simplified equation for methane intensity in real-time on their sites. Therefore, the commenter suggests more research and tools must be developed before this option can be written into the rules. However, perhaps EPA could craft a suitable alternative to the absolute Detection and Action thresholds proposed, without requiring its use.

Response II-5-154: EPA acknowledges the commenters' input.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) support the proposal by the EPA to set action levels based on methane emissions rates rather than methane concentrations, in part, for the reasons provided in this solicitation. The commenters believe that

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<sup>70</sup> Supplemental Proposal, at 74,744 ("EPA is also aware of industry led efforts to minimize methane emissions through the entirety of the value chain using the percentage of intensity or production as a metric. The EPA is soliciting comment on the potential use of intensity or production in the development of action levels, including appropriate thresholds for setting such action levels on both a short-term and long-term basis.")

the use of methane emissions rates will more closely harmonize with other rules currently in and planned for development, including the future revision to 40 CFR part 98, subpart W, as required by the IRA.

Response II-5-155: EPA acknowledges the commenters' support of the rule.

Comment: Commenter (2421-Teledyne) states another concern with both the periodic and continuous technologies is the determination of minimum detection threshold and how the EPA intends to set standards for these technologies to meet desired thresholds of detection. With the BSER technology, OGI, the EPA specifically designated minimum technology standards with respect to the capabilities of the technology. As an example, NSPS OOOOa regulation defined OGI as technology that must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of  $\leq 60$  g/hr from a quarter inch diameter orifice. In this supplemental proposal the EPA has set new parameters around this technology as determined in Appendix K including a new minimum detection threshold of 17 g/hr of methane. The EPA should be more descriptive as to how they will ensure that periodic and continuous technologies are developed and implemented appropriately to ensure the desired capabilities are met.

Response II-5-156: As explained in Section X.B.3 and XI.B.3, EPA has defined the criteria that alternative methane detection providers must provide to the EPA as part of their request to approved. This criterion includes a requirement to prove a provider can achieve the required detection limit under conditions as found in the field.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) say that if the Final Rule allows operators to use continuous monitoring systems under the periodic screening matrix, EPA will need to approve action levels as part of the work practice standards to be submitted to EPA under Proposed OOOOb §60.5398b(d) for certain technologies rather than requiring a response with each detection. EPA correctly recognized that action levels are the right response definition for continuous monitoring systems that are capable of quantification and fullsite coverage. Some non-visual continuous monitoring technologies (e.g., point and open path sensors) and periodic screening technologies (e.g., plane or drone-based mass-balance technologies) detect both allowable emissions (e.g., compressor methane slippage) and fugitive emissions because they measure site-wide emissions. Thus, the work practice standards should allow site-wide continuous monitors to quantify baseline emissions through time and identify emissions that exceed the sum of the baseline emissions plus the action levels defined in the matrix. Of note, camera-based continuous monitoring solutions do not require baseline measurement as part of their work practice standards as they can distinguish permitted emission from process malfunctions. Thus, each work practice standard approved by EPA can include the specific criteria (e.g., a combination of emission rate and duration) that triggers a detection or action level, which requires an owner or operator to identify the cause of the emission or process malfunction through an investigative analysis.<sup>71</sup>

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<sup>71</sup> Methane Roundtable Letter 1 (text under the heading "EPA should ensure that owners and operators can use continuous emission monitors under the periodic screening matrix and that response requirements are technology neutral.").



Commenter (2298-Pioneer) argues the work practice standard for continuous monitoring technologies should specify how many detections in a month should trigger a detection that requires an owner or operator to identify the source of the leak or process malfunction.

The commenter adds some continuous monitoring technologies and periodic screening technologies (*e.g.*, mass-balance technologies) will detect allowable emissions. To ensure owners and operators can respond to leaks and process failures, EPA will need to establish action levels that differ from detection levels to determine an owner or operators' response requirements. EPA can use its process for alternative test method approval for alternative technologies to identify the process by which to identify baseline emissions versus the action levels.

Response II-5-157: EPA acknowledges the commenters' input; EPA wrote the continuous program as a performance-based approach. We recognize that many current continuous solutions may not be able to meet the criteria in the approach however we recognize the value of the more continuous systems and EPA has revised the final rule to confirm that methane detection technology that operates more continuously could be used in the alternative periodic screening approach as detailed in Section X.B.1 and XI.B.1 of the preamble of the final rule.

#### ***5.9.6 Probability of Detection***

Comment: Commenter (2433-EDF *et al.*) states technology parameters are an important input for the FEAST model that affect the results and should also inform EPA's technology approval process, which applies to new technologies before they are deployed in the field for compliance purposes. Default FEAST inputs for technology parameters are based on probability of detection curves derived through controlled testing studies. Because technologies may perform differently under varying meteorological and geographic conditions, it is also possible to alter the technology parameters based on the intended uses. For example, an operator evaluating the effectiveness of aerial technologies that it intends to deploy in North Dakota might alter the technology inputs to reflect decreased performance in windy and snowy conditions. Conversely, an operator in the Texas Permian might assume better technology performance due to relatively more consistent weather and geographical conditions there.

Commenter (2433-EDF *et al.*) notes EPA appropriately excluded regionally variable factors like wind speed and snow cover, relying instead on broadly applicable and averaged assumptions derived from controlled testing. Because technologies permitted for compliance may be deployed anywhere across the country at any time, it would not be possible nor reasonable for EPA to attempt to evaluate performance or set standards based on varying meteorological and geographical conditions. Such considerations are instead better resolved during the new technology approval process or AMEL applications.

Response II-5-158: EPA acknowledges the commenters' input; EPA agrees with the commenter and recognizes that environmental conditions are extremely important component of POD. EPA has revised the required information an alternative technology provider must provide to the EPA as part of their alternative test method request as described in Section X.B.3 and XI.B.3 of the final rule.

EPA may provide caveats to any alternative test method approval to ensure a technology is being utilized properly.

Comment: Commenter (2340-Honeywell) requests that the final rule should provide a flexible framework for determining action levels and measurement averaging periods that require a minimum probability of detection.

Commenter (2340-Honeywell) states continuous monitoring sensors generally apply plume modeling to determine the mass emissions rate of a leak (in kg/hr) from concentration data measured by the point sensors, which is correlated in time with wind direction and speed. Because the continuous monitoring system is dependent on the variability of the wind direction to bring methane molecules from the emission point to the sensor, a certain amount of data collection is needed to build up enough statistics. This is dependent on dynamic weather conditions, but also on detector distances and detector sensitivity. Integrating those data to determine the mass emissions rate involves some inherent uncertainty based on the precision of each measurement. This is true as well for OGI cameras, which constitute BSER. As EPA notes in the preamble to the proposal, weather conditions and operator experience can significantly affect the detection capabilities of OGI cameras, which is why EPA has proposed standards for operator experience and require that such surveys only take place within a particular “operating envelope” of field conditions.

Commenter (2340-Honeywell) argues rather than limit the action levels, detection sensitivities, and measurement averaging periods (*i.e.*, the 7- and 90-day measurement periods) to one set of prescribed levels based on flawed FEAST modeling, the final rule should provide the flexibility to use modeling to determine the action levels and corresponding measurement periods for continuous monitoring systems, and require a minimum probability of detection instead of prescribing minimum detection thresholds. Doing so will better serve EPA’s goal of creating an outcome-based, technology-neutral standard that encourages the development and deployment of a wide variety of effective continuous monitoring systems. The commenter proposes that the final rule allow the use of both FEAST modeling and plume/inversion modeling to determine the detection thresholds at which a particular system can meet a minimum probability of detection and to set the appropriate action levels and measurement periods that provide equivalent emissions reductions.

Commenter (2340-Honeywell) states first, the final rule should allow for the use of plume or inversion modeling to determine, with independent verification, the threshold subject to a probability of detection requirement and placement of sensors in relation to a source at which a particular continuous monitoring technology can meet the requisite probability of detection. In order to determine the threshold for different continuous monitoring systems (*e.g.*, a fenceline system with highly sensitive detectors positioned far away from the emissions as compared to a hazloc system with lesser sensitive detectors positioned very close to the emissions) and the corresponding probability of detection, the commenter proposes the use of probability curves. For consistency with the alternative periodic screening framework, EPA may consider setting the baseline at a 90% probability of detection. Third-party research institutions, such as METEC, are already developing methodologies for testing advanced methane detection and determining probability curves for the detection sensitivity of such instruments; EPA should allow continuous

monitoring technology providers such as Honeywell to rely on the probability curves developed by third-party validators, such as METEC, to demonstrate the requisite detection level for their continuous monitoring systems.

Commenter (2340-Honeywell) continues second, based on the detection threshold at which the continuous monitoring system can measure a methane leak with the requisite probability of detection, the technology provider or operator should then be able to use FEAST modeling (or a similar method), to determine the combination of action levels and measurement periods that would provide equivalent emissions reductions to BSER. For example, an operator using a less sensitive instrument and a higher action level could measure a rolling average of emissions on a shorter timeframe (*e.g.*, a 1-day measurement averaging period with a 30 kg/hr action level). In the commenter's experience, some operators find that the best use case for continuous monitoring systems is to trigger corrective action sooner in response to larger emissions, while other operators focus on longer-term trending. Either approach can provide equivalent or greater emissions reductions to BSER and to periodic screening given the frequency of measurement. EPA used FEAST modeling to determine equivalency for the detection thresholds and monitoring frequencies provided in the periodic screening matrices and to set the action levels for continuous monitoring. It should therefore be possible to apply the same type of modeling to a variety of detection thresholds and action levels to determine the frequency of action that would provide equivalent or greater emissions reduction to BSER for continuous monitoring.

Commenter (2340-Honeywell) states third, EPA can establish certain boundaries and backstops, as it has done with the periodic screening matrices, that ensure equivalency with BSER. For example, similar to the upper limit of a 30 kg/hr detection threshold for periodic screening, the final rule could establish an upper limit of action levels that provides sufficiently equivalent emissions reductions to BSER. Honeywell proposes, for example, that the framework allow for an upper action level of 30 kg/hr for which an operator would use a 1-day rolling average for the measurement period. The final rule could similarly incorporate OGI backstops, as the periodic screening matrices do, for certain action levels used for continuous monitoring.

Commenter (2340-Honeywell) concludes the final rule should allow the use of modeling to (a) determine the detection level at which a given continuous monitoring system can provide a minimum-prescribed probability of detection (*e.g.*, 90%), and (b) determine the corresponding action levels and frequencies of action that would provide equivalent emissions reductions to BSER. With regard to the demonstration of the technology's probability of detection, the commenter recommends that EPA allow technology providers to rely on third-party validation, such as that provided by METEC, of a continuous monitoring system's probability curve with respect to its detection thresholds.

Response II-5-159: EPA acknowledges the commenter's input. EPA has explained the criteria for the alternative periodic screening, continuous applications, and the approval process for these alternative technologies in Sections X.B and XI.B of the final rule. EPA has not provided a pathway for technology specific work practices using FEAST modeling however, when appropriate, and individual could petition the Administrator for an AMEL.

Comment: Commenter (2405-Bridger) believes that meaningful detection sensitivity performance metrics should be required for continuous monitoring systems. The Proposed Rule indicates that the detection sensitivity of continuous monitoring systems should be an order of magnitude smaller than the action levels specified for the continuous monitoring approach. However, the performance metric for sensitivity is not defined. The commenter recommends that detection sensitivity is defined as the emission rate at which the technology has a 90% probability of detecting emissions, consistent with the requirements for periodic screening technologies. Using minimum detection levels is not suitable because it may have little bearing on field performance. Detection probabilities for continuous monitoring systems have already been evaluated by a third party, which illustrates that this is a practical requirement.

Commenter (2405-Bridger) states the demonstration of detection probabilities should be applicable to sites where the continuous monitoring technology will be deployed to ensure that systematic false negative detections do not occur due to exceedingly sparse spatial coverage (e.g., lofted emissions from tanks or flares could be missed and very specific sensor configurations and numbers may be required at individual facilities;<sup>72</sup> certain wind angles and speeds may be necessary for these systems to appropriately detect, quantify, and localize emissions).

For consistent and meaningful performance demonstration, commenter (2405-Bridger) urges the EPA to require continuous monitoring systems to report their detection sensitivity at 90% probability of detection

Response II-5-160: EPA acknowledges the commenters input. In the final rule, EPA has revised the requirement around detection threshold/probability of detection to require technology vendors provide us information on these thresholds as applied in the field. The 90% probability of detection is required for any technology operated under the periodic screening alternative; however, EPA is using detection threshold which is intended to be MDL for those systems as applied in the field.

Comment: Commenter (2402-DGCC) states the Supplemental Proposal provides guidance about how continuous monitors should be used with action levels corresponding to 7-day and 90-day rolling average windows. Many continuous monitors are used to find leaks quickly and measuring a leak for 90 days before acting is not consistent with the best use of many continuous monitors. More effective continuous monitoring would occur with different durations of rolling average windows.

Commenter (2402-DGCC) recommends that in addition to the prescribed 7-day and 90-day rolling average windows, EPA make clear that requestors can submit FEAST modeling as part of their applications (under proposed OOOOb §60.5398b(d)) with different rolling average windows, customized to maximize the effectiveness of the continuous monitoring technology. Some continuous monitors are most effective when deployed using two rolling average windows, but other continuous monitors are most effective when deployed using a different number of rolling average windows. In all cases, FEAST modeling would ensure that the action

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<sup>72</sup> Chen, Q. et al. Assessing Detection Efficiencies for Continuous Methane Emission Monitoring Systems at Oil and Gas Production Sites. Environ Sci Technol (2023). doi: 10.1021/acs.est.2c06990.

levels are set corresponding to the number and duration of rolling average windows to ensure that the resulting emissions reductions are equivalent to the BSER.

Commenter (2402-DGCC) adds, EPA should make clear in the Final Rule that requestors can submit applications for a combination of periodic screening technologies and continuous monitoring technologies. Such applications should include FEAST modeling with the same input emissions distribution EPA uses in the Final Rule to enable EPA to evaluate those applications within the proposed 270 days alternative test method approval process.

Commenters (2336-Kuva, 2402-DGCC) note proposed Tables 1 and 2 to Subpart OOOOb of Part 60 (presented as Tables 20 and 21 in the Supplemental Proposal) provide survey matrices for alternative periodic screening approaches based on EPA's FEAST modeling and simulations. The matrices provide guidance on five minimum screening frequencies versus their corresponding minimum detection thresholds of screening technology, which are expressed as a 90% probability of detection threshold. In developing the detection limits for the matrix, EPA makes two critical assumptions in its FEAST modeling:

1. The statistical distribution of fugitive emissions, of super emitters and their intermittency
2. All emissions at a site at and above the detection limit listed in the matrix are detected with a 90% probability by the advanced technology for every screening and that no emissions are detected below the listed detection limit.

Response II-5-161: EPA acknowledges the commenter's input. EPA has explained the criteria for the alternative periodic screening, continuous applications, and the approval process for these alternative technologies in Sections X.B and XI.B of the final rule. EPA has not provided a pathway for technology specific work practices using FEAST modeling however, when appropriate, and individual could petition the Administrator for an AMEL.

Comment: Commenters (2336-Kuva, 2402-DGCC) state the second assumption in EPA's FEAST modeling is a disincentive for operators to utilize advanced technologies if the currently proposed language is interpreted by EPA as requiring alternative technologies to detect emissions from every fugitive component, cover, or CVS at a site at 90% probability of detection for every screening. Advanced technologies may not be able to guarantee this due to technology-specific circumstances related to site coverage and visual obstruction. At the same time, alternative technologies will detect significantly more emissions than assumed by EPA in its FEAST modeling due to the impact of the complete probability of the detection curve, which EPA's FEAST modeling does not currently consider. These incremental detections, due to the probability of the detection curve, can more than offset reduced detections due to visual obstruction or other coverage-related issues. Alternatively, an advanced technology solution provider may offset site coverage limitations with a lower limit of detection than required under the matrix.

Commenter (2336-Kuva) adds continuous camera solutions can detect significantly more emissions than assumed by EPA in its FEAST modeling due to the following three parameters:

- Impact of the complete probability of detection curve;

- Increase of screening frequency beyond monthly, for example once per week at a set point in time; and
- Impact of distance on probability of detection.

Commenters (2336-Kuva, 2402-DGCC) continue, a guarantee of detecting emissions from every fugitive component, cover, or CVS at a site at a 90% probability for every screening inspection may not be possible for many sites. Examples are:

- Venting from compressor rod packing at compressors that are covered by a roof may not be detectable by plane surveys due to lack of line of sight to the vent and the vent plume will be too dilute for detection once it is blown sideways out under the roof.
- An emissions plume from methane emissions slippage at compressors may frequently cover up underlying fugitive emissions from fugitive components in the vicinity of a compressor and make them undetectable by visual aerial detection. Any fugitive emissions will intermingle with the methane emissions slippage and will then be considered a permitted emission from the compressor instead of being detected.
- Emissions from high-up sources such as thief hatches on tall tanks may not drift down towards point sensors or reflector installations of open path detectors installed lower to the ground.
- Continuous installed OGI cameras may not have a direct line of sight to yard piping or other fugitive components due to visual obstruction behind storage vessels or other large structures
- Challenges with site coverage also exist for OGI inspections as EPA proposes exemptions for “Unsafe to inspect” or “Difficult to inspect” components in its OGI inspection requirements for covers and CVS.
- camera based continuous monitoring systems may not have direct line of sight to yard piping or other fugitive components due to visual obstruction behind storage vessels or other large structures.

Response II-5-162: EPA acknowledges the commenter’s input. It is requisite in this and any other fugitive/covers and CVS monitoring program to monitor each component individually and in this rule, we have introduced an alternative’s which allow the owner or operator to measure the aggregate so long as they have entire site coverage. EPA recognizes that each technology offers its own benefits and challenges, and therefore as explained in Section X.B.3 and XI.B.3 have allowed for the development of technology specific alternatives.

Comment: Commenter (2402-DGCC) states concurrently, advanced technologies do not have a fixed “cutoff value” for a detection limit as is assumed in EPA’s FEAST modeling, but instead a probability of detection curve that will detect emissions at lower emission rates at a probability below 90%. This will result in very significant additional emissions reductions as the frequency of emission events occurring is larger at lower emission rates. Alternatively, some advanced technologies will also have a 90% probability of detection limits that are below EPA’s matrix limit while still suffering from the site coverage constraints as described above.

Commenter (2402-DGCC) states the FEAST and Highwood Emissions Management's LDARSim models are capable today of modeling these limitations.<sup>73</sup> Specifically, they can model the incremental detection capabilities of advanced technologies due to their probability of detection curve or due to lower detection levels and they can model the reduced detection due to technology-specific limitations in site coverage. EPA could consider making assumptions in their FEAST modeling of on-site coverage and probability of detection curves. However, this may be challenging to implement in a technology-neutral way as the specifics of site coverage and of the shape of a probability of detection curve vary by advanced technology.

Commenter (2402-DGCC) recommends that EPA clarify that advanced technology solution providers can submit to EPA, under the alternative test method approval process, technology-specific FEAST modeling to demonstrate that their alternative test method and related work practice utilizing a combination of site-coverage parameter and probability of detection curve or improved detection limit results in equivalent or greater emission reductions compared to the matrix (combination of detection limit and screening frequency), which EPA has demonstrated is equivalent to BSER. The newly introduced site coverage parameter will become a part of the technology-specific work practice that has to be followed by operators for all sites. EPA should make clear that applicants can make this demonstration if they use EPA's assumptions in the Final Rule's FEAST modeling for the statistical distribution of fugitive emissions and for super emitters and their intermittency while being permitted to introduce an explicit parameter for less than 100% site coverage (and a corresponding coverage requirement in the technology-specific work practice) and for either using a lower detection limit than required by the matrix or for modeling a full probability of detection curve instead of a cutoff value.

Commenter (2402-DGCC) states there are currently no provisions pertaining to the simultaneous deployment of combinations of alternative technologies. Deploying alternative technologies in combination can allow the complementary strengths of the different technologies to be combined in practice. More effective monitoring can occur in many situations if different technologies are combined. Studies show examples of how periodic screening technologies and continuous monitoring technologies can be deployed in combination to achieve particularly effective monitoring.<sup>74</sup> Moreover, some operators may be willing to agree to a faster response time to detected emissions than required by EPA. The response time assumption is a significant variable in FEAST modeling—a faster response will increase the reduction of emissions. An example is a faster response to abnormal emissions from abnormal venting from fugitive components, covers, or CVSSs.

Commenter (2402-DGCC) states EPA's proposed rule includes only five combinations of detection limit and screening frequency for the screening matrix. This limits the flexibility of deployment of existing or future advanced technologies. For example, advanced technologies may be more cost-effective when deployed at a different combination of detection limit and screening frequency than anticipated by the EPA.

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<sup>73</sup> LDARSim. (N.D.) Highwood Emissions Management. <https://highwoodemissions.com/ldarsim/>.

<sup>74</sup> Cardoso-Saldaña, F.J. (2022, Nov. 15). Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities. ExxonMobil Upstream Research Company. <https://chemrxiv.org/engage/chemrxiv/article-details/636d4595afea7fed1c9f5f67>.

Commenter (2402-DGCC) recommends that EPA clarify that advanced technology solution providers can submit to EPA, under the alternative test method approval process, technology-specific FEAST modeling to demonstrate that their alternative test method and related work practice utilizing : 1) a combination of screening technologies, 2) different requirement for operator response times to alarms, or 3) a different combination of detection limit and screening frequency. The EPA has demonstrated such practices are equivalent to BSER.

Commenters (2336-Kuva, 2402-DGCC) add the newly introduced parameters (*e.g.*, a combination of screening technologies, response times, detection limits, and screening frequencies) will then become a part of the technology-specific work practice that has to be followed by operators for all sites utilizing this technology. EPA should make clear that applicants can make this demonstration if they use EPA's assumptions in the Final Rule's FEAST modeling for the statistical distribution of fugitive emissions and for super emitters and their intermittency, while being permitted to introduce explicit parameters accounting for less than 100% site coverage (and a corresponding coverage requirement in the technology specific work practice), for modeling a full probability of detection curve instead of a cutoff value, for increasing screening frequency and for utilizing distance dependent detection curves (and related placement constraints for the camera).

Commenter (2336-Kuva) indicates that challenges with site coverage also exist for OGI inspections. EPA has accommodated these challenges by proposing exemptions for "Unsafe to inspect" or "Difficult to inspect" components in its OGI inspection requirements for covers and CVS in the current supplemental proposal.

Instead of creating exemptions for continuous cameras, commenter (2336-Kuva) is proposing for EPA top permit applicants for alternative test methods to consider other parameters in their application, namely Impact of the complete probability of detection curve, Increase of screening frequency beyond monthly, for example once per week at a set point in time and the impact of distance on probability of detection.

Commenter (2336-Kuva) notes EPA is currently not considering the complete probability of detection curve in its modeling and instead uses the 90% detection limit as a cut-off value. In a real-world deployment a continuous camera will also detect and can also alarm on emissions significantly below its 90% detection limit. Publications show that the 10% detection limit can often be a factor 10 or more below the 90% probability of detection limit. These detections contribute very significantly to the overall number of emissions detections as the frequency of smaller leaks is higher than for larger leaks. Unlike point sensors and scanning laser towers continuous cameras do not require a baseline measurement to be subtracted and they do not require an action level that is typically far higher than a detection limit. Instead, in principle cameras can alarm on all detections irrespective of size of the emissions.

Commenter (2336-Kuva) states an increase in screening frequency (for the same detection limit) will have a beneficial effect on emissions reductions as super emitters, and especially intermittent super emitters, are more likely to be detected and repaired quickly.



Commenter (2336-Kuva) states the probability of detection for cameras is dependent on the distance from emission. In a typical installation a continuous camera is installed such that distance to likely super emitters such as tanks is minimized, thereby increasing the likelihood that even small emissions are captured. This distance dependent probability of detection can be captured in FEAST modeling and in installation requirements as part of the work practice, for example an installation requirement that a certain percentage of components have to be within a certain distance from a camera.

Commenter (2336-Kuva) argues all three of these parameters are currently not considered in EPA's FEAST modeling. Incremental detections due to these three parameters can more than offset reduced detections due to visual obstruction or other coverage related issues. The FEAST and LDARSim models are capable today of modeling these limitations. Specifically, both FEAST and LDARSim can model the incremental detection capabilities of advanced technologies due to their probability of detection curve, due to increased detection frequency or due to probability of detection curves for multiple distances (by combining multiple simulations runs). LDARSim can model the reduced detection due to technology specific limitations in site coverage today and this feature is planned as an update for the near future for FEAST.

Commenter (2336-Kuva) states in establishing a Matrix EPA could consider making assumptions in their own FEAST or LDARSim modeling on site coverage, probability of detection curves, increased detection frequency or distance dependent detections. However, this would be very challenging to implement in a technology neutral way as the specific impact of each parameter varies very significantly with each type of advanced technology.

Response II-5-163: EPA acknowledges the commenters' input. An alternative to the alternative periodic screening or continuous monitoring approach using advanced methane detection technology, you may choose to petition the Administrator for an Alternative Mean of Emission Limitations (AMEL) for the fugitive monitoring program in §60.5397b. The criteria for this program are defined in §60.5399b.

### ***5.9.7 Matrix Approach***

Comment: Commenters (2213-Oxy, 2433-EDF *et al.*) appreciate EPA's inclusion of a matrix framework that allows alternative technologies to be used for varying survey frequencies based on the resolution of the technology. The commenters appreciate the inclusion of a framework for continuous monitoring systems based on certain action levels and supports the use of these technologies in lieu of the conventional AVO and OGI surveys.

Response II-5-164: EPA acknowledges the commenter's support for the matrix framework.

Comment: Commenter (2433-EDF *et al.*) states EPAs proposed quarterly OGI matrix aligns with their independent FEAST modeling results across a variety of scenarios and the commenter therefore supports the proposed frequencies. Commenter's (2433-EDF *et al.*) results for aerial technologies paired with annual OGI are similar to EPAs, and the commenter believes the proposed frequencies are appropriate. In coming years, detection capabilities are likely to improve, and the commenter supports EPA's inclusion of options that will drive this

improvement. Last, while EPA's FEAST results show that the addition of an annual OGI survey is necessary for equivalence for only some of the options, the commenter encourages EPA to nevertheless require a universal annual OGI backstop and ensure that any higher detection threshold options contain OGI pairings. Commenter (2433-EDF et al.) believes this is necessary to mitigate smaller (but cumulatively significant) persistent leaks that are detected under EPA's BSER determination for OGI but unlikely to be detected through advanced screening. The OGI pairing will also become increasingly important as super-emitters are reduced and begin to contribute less to total emissions.

Response II-5-165: EPA acknowledges the commenter's support for EPA's FEAST modeling.

Comment: Commenter (2433-EDF et al.) states for sites that would be subject to semiannual OGI or quarterly AVO (wellhead only and small well sites), EPA has proposed a different matrix that would achieve reductions equivalent to semiannual OGI. The commenter supports the frequencies and detection thresholds in this matrix also, and in particular believe the annual OGI pairings with the higher detection threshold technologies are appropriate. Sites subject to this matrix will often be producing very little and may not regularly experience large emission events. Consequently, many emissions at these sites are likely to be smaller leaks that may be missed by high detection threshold screening technologies. To mitigate these leaks thus requires the use of a more sensitive technology, like OGI.

Commenter (2433-EDF et al.) states most operators choosing the alternative advanced monitoring option will likely contract with a methane mitigation provider and will choose the alternative for a grouping of assets or all their assets. Operators typically also have mixed assets, meaning they have a variety of site types, some of which will fall into different monitoring subcategories. Screening all of an operator's sites based on the most stringent applicable requirement would therefore pose minimal additional burden in many cases. For example, if an operator owns twenty-two well sites in a basin, half of which would fall into the quarterly OGI matrix, and half of which would fall into the semiannual OGI matrix, the operator will likely screen all the sites pursuant to the more stringent requirement. In light of the potential efficiency advantages to applying the same approach to all sites in a geographic area, operators should be permitted to apply the most protective version of the matrix to groupings of sites.

Commenter (2433-EDF et al.) states EPA should also require some form of ongoing OGI or AVO inspections at all sites complying with this matrix as a backstop. For the reasons described in section IV.B.d.v, Commenter (2433-EDF et al.) thinks that AVO inspections are particularly valuable for declining end-of-life wells and reducing the risk of orphaning. Without some form of regular, ground-based inspection, operators may never visit these sites and preventative maintenance may never occur. Ground-based inspections better serve the purposes of regular upkeep and site hygiene that are important for end-of-life wells in particular and should therefore be required at all wellhead-only and small well sites.

Commenter (2433-EDF et al.) believes that EPA should revisit the assumptions underlying the matrices in the future. As large emission events are reduced through implementation of EPA's proposed standards, the commenter expects that emissions distributions across basins will become less heavy tailed. This means that higher detection threshold options will become less

effective over time as the fraction of total emissions below their detection threshold increases. Therefore, to achieve reductions equivalent to OGI, frequencies will need to increase, and detection thresholds will need to decrease. Further, the commenter expects that costs and improved detection capabilities will obviate the need for higher detection threshold options in the future.

Response II-5-166: EPA acknowledges the commenter's input and support. EPA agrees with the commenter that ongoing OGI is beneficial, however we found that it is not always necessary. EPA also agrees that we should revisit assumptions in the matrix as part of any future regulatory actions required by the Clean Air Act.

Comment: Commenters (2213-Oxy, 2428-API) have concerns with the proposed frequencies and action levels, respectively. The proposed frequencies and action levels may not promote the use of these technologies, and OGI/AVO may still be a more resource-efficient approach for many operators. Commenter (2213-Oxy) states for continuous monitoring systems, action levels should be reflective of the facility type, complexity, and design and should be in addition to authorized emissions to focus on identifying and resolving leaks and abnormal conditions. The commenter is supportive of the framework and believes that EPA can encourage the continued innovation and accelerated deployment of these technologies even more strongly in the final rule by incorporating the feedback mentioned above.

Response II-5-167: EPA acknowledges the commenter's input; EPA has set the action levels in the continuous monitoring approach and the matrix frequencies to be equivalent of the BSER.

Commenter (2428-API) states that the proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. The commenter recommends incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework.

Response II-5-168: EPA never intended to exclude continuous type technologies from being applied in the periodic screening approach. EPA has made the necessary changes in the final rule as described in Sections X.B.2 and XI.B.2 of the preamble of the rule.

### **5.9.8 FEAST Modeling**

Comment: Commenter (2433-EDF *et al.*) states EPA's decision to use FEAST to model the effectiveness of different methods and advanced technologies is reasonable.<sup>75</sup> FEAST is a

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<sup>75</sup> Fugitive Emissions Abatement Simulation Toolkit, SET Lab, <https://www.arvindravikumar.com/feast/> (last visited Feb. 13, 2023).

customizable, open-source modeling framework developed to evaluate the effectiveness of different LDAR programs at oil and gas facilities. Model inputs include the number and type of emissions sources, a leak generation rate by emission source type, a distribution of leak rates when a leak is generated, and the probability of the selected method detecting a leak of a given size. FEAST can therefore evaluate the effectiveness of different LDAR approaches, as well as voluntary programs undertaken by operators.

Response II-5-169: EPA acknowledges the commenter's input and support.

Comment: Commenter (2433-EDF *et al.*) believes that all of the inputs used by EPA are reasonable, appropriate, and ensure that advanced technologies deliver emission reductions commensurate with OGI across diverse basins. Innovation in methane detection technologies and deployment methods is advancing rapidly and EPA has taken a careful, technology-neutral approach that will enable the use of these technologies for regulatory compliance. EPA's proposed approach provides operators and technology providers with flexibility, while ensuring most critically that these technologies are used in a way that ensures emission reductions equivalent to OGI at all sites nationwide.

Commenter (2433-EDF *et al.*) notes EPA chose inputs and made assumptions based on nationally applicable factors and considerations. This is both appropriate and required by CAA section 111, which applies across the country to sources in different oil and gas producing regions and basins. While technologies and methods may perform differently in different regions and under varying conditions, EPA is required to ensure that equivalent performance will occur everywhere and under all conditions. EPA's modeling does this and the commenter therefore support the results, which also generally align with the results of independent modeling conducted with nationally applicable input assumptions.

The commenter's (2433-EDF *et al.*) primary recommendation is that EPA require ongoing ground-based inspections at all sites as a backstop. As an optional alternative to the OGI-based approach, EPA proposes to allow operators to use advanced methane detection technologies at varying frequencies (and with varied OGI pairings) depending on detection capabilities—a "matrix" approach. The requirements also vary by site type, tracking the subcategories described above. The proposed changes to the alternative screening option are intended to support the deployment and utilization of a broader spectrum of advanced measurement technologies than the initial proposal. EPA has therefore proposed two matrices of options that are expected to achieve emission reductions equal to or greater than OGI:

[Table 6 Number of Reported Leaks by Component Type]

[Table 7 Quarterly OGI Subject Sites: Frequency by Detection Capability]

[Table 8 Semiannual OGI & AVO Subject Sites: Frequency by Detection Capability]

Commenter (2433-EDF *et al.*) believes the frequencies and detection thresholds included in the matrices are largely appropriate and will ensure that equivalent emission reductions occur at all sites nationwide. The commenter's own FEAST modeling results using nationally representative

emissions distributions generated results similar to what is included in the matrices (described more below). The commenter also notes that EPA's results are intuitively correct given that OGI has a detection threshold below 1kg/hr, any technology that is less sensitive must be used at a higher frequency to achieve the same emissions reductions. As the detection threshold increases, so does the fraction of total emissions that cannot be detected by that technology. Therefore, to achieve the same level of emissions reduction as quarterly (or semiannual) OGI, technologies with higher detection thresholds must be used more frequently. And with very high detection thresholds, it is not possible to achieve the same level of reductions, regardless of frequency, because too large of a fraction of total emissions exists below the detection threshold.

Commenter (2433-EDF *et al.*) states prior to deploying a technology for regulatory compliance, EPA would have to approve the technology as meeting the parameters outlined in the proposal and matrices. EPA is proposing to streamline the pathway for technology developers and other entities to seek the agency's approval for the use of advanced measurement technologies under the alternative screening option. Approved technologies could then be deployed following the same operational parameters under which they were approved.

Commenter (2433-EDF *et al.*) states an operator choosing the screening approach must submit a monitoring plan identifying the sites, test methods, technology vendor, planned frequencies, follow-up survey plans, and repair plans. Upon detection of emissions, ground based OGI surveys are required, and repairs must be completed within 30 days of the screening survey. Root cause analysis and corrective action are required if the emissions are due to failure of a control device, a cover, or a closed vent system. The commenter supports EPA's proposed structure, matrices, deployment and repair requirements, and technology approval process.

Response II-5-170: EPA acknowledges the commenter's input and support.

Comment: Commenter (2340-Honeywell) states that the framework for continuous monitoring in the proposed supplemental rule appears to be based on modeling and assumptions that do not reflect the real-world deployment and capabilities of such systems or their efficacy in detecting methane emissions.

Response II-5-171: The continuous monitoring action levels are based off the expected emission reductions in the model plan for the BSER program (OGI). The action levels are independent of how any continuous monitoring solution has been applied.

Commenter (2340-Honeywell) states first, EPA explains in the supplemental proposal that the continuous monitoring framework is akin to the NESHAP fenceline monitoring work practice and assumes that continuous monitoring sensors would similarly be placed on the fenceline of the facility. However, Rebellion cameras and Signal Scout sensors are both placed within the fenceline and at the heart of the operations. In fact, Signal Scout sensors are placed directly adjacent to the emissions sources because they are hazardous area certified. Both systems are therefore much closer to potential leaks than technology deployed on the fenceline. Such systems do not need to be as sensitive as fenceline-based sensors to detect leaks of a particular size.

Response II-5-172: EPA acknowledges the commenters' input, EPA has made revision in the continuous monitoring provisions in the rule, as explained in Section X.B.2 and XI.B.2 to allow for additional monitoring solutions to use this approach. Likewise, these types of technologies could also be used in the periodic screening approach.

Comment: Commenter (2340-Honeywell) states data from the commenter's test deployment of Signal Scout indicate that a substantial number of large emissions events tend to be from process upsets, such as thief hatch releases and seal failures, that tend to be of limited duration (*e.g.*, less than 12-24 hours) and occur intermittently. Data from Signal Scout deployment in the field indicate that these intermittent events contribute significantly to overall site emissions. However, EPA's FEAST modeling—which is the basis for the equivalency analysis between periodic screening, continuous monitoring, and BSER—is based on data from periodic screenings (*e.g.*, aerial data). This data may not take into account these types of intermittent, shorter duration emissions of several hours, but which are nevertheless large emissions events. As shown below, for example, current FEAST modeling assumes that large emission events (referred to as super-emitters in the presentation cited below) are persistent or continuous over a longer duration of 5–45 days (rather than intermittent over a period of several hours) such that periodic surveys would be more likely to detect them.<sup>76</sup>

[Table of FEAST-EPA Model assumptions. Supplemental proposal FEAST assumption versus alternative modeling scenarios in FEAST]

Commenter (2340-Honeywell) states data shows that this assumption is flawed, and the failure to incorporate shorter-duration, actionable and large emission events of several hours into the modeling biases the equivalency determination in favor of alternative periodic screening, because it then fails to account for the advantages of continuous monitoring in detecting such events and thus contributing to overall emissions reductions. In addition to evading periodic surveys, these types of large emission events of several hours' duration do not require minimum detection thresholds as low as those proposed in the rule (*i.e.*, 0.12 kg/hr or 0.16 kg/hr) to be detected by continuous monitoring technologies. When these larger intermittent emissions events are taken into account, it becomes clear that continuous monitoring systems are likely to provide significant overall emissions reductions, and potentially much greater reductions as compared to periodic surveys. Taking this dynamic into account would allow EPA to relax the parameters necessary to determine equivalency between continuous monitoring and BSER.

Commenter (2340-Honeywell) argues prescribing inappropriately low action levels and detection thresholds undermines the purpose of LDAR programs to maximize emissions reductions, because doing so will push technology providers and operators toward the use of periodic screening over continuous monitoring. Instead, EPA should allow for a range of action levels and measurement averaging periods and set detection thresholds based on the probability of detection when using that particular technology to ensure sufficient sensitivity in a technology-neutral manner (whether it is on the fenceline or in the heart of the operations).

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<sup>76</sup> See “EEMDL Launch Event: FEAST and the EPA Supplemental Rule,” p. 25, available at: <https://static1.squarespace.com/static/62e9555e53fbc63d4431547e/t/63c855f7411588605e3859a1/1674073622398/EEMDL+Launch+Webinar+Presentation.pdf>.

Comment: Commenter (2340-Honeywell) believes the current FEAST modeling on which EPA is utilizing for this rulemaking is limited because it relies heavily on data from periodic screening technology (e.g., aerial survey data) without benefit of commensurate data from continuous monitoring systems. One key area of weakness in the current FEAST dataset is with regard to the contribution of large emission events of limited duration that can dramatically impact annualized emission estimates and the ability of an operator to understand the root causes in order to respond quickly and reduce or prevent these emission events.

Response II-5-173: As previously discussed, the action level for the alternative continuous monitoring work practice is independent of what a technology can do and are based on the expected emissions of the BSER. The sensitivity requirements are based on the annualized emission rate of the BSER program and if a continuous technology cannot measure those levels, then we cannot assume that the alternative work practice is getting the equivalent emission reduction.

Comment: Commenter (2340-Honeywell) notes a study by Schissel, and Allen assessed the impact of emission intermittency on the ability of annual, semiannual, quarterly, monthly, and weekly measurements to accurately detect emissions, including large, short-duration events. They found significant uncertainty and bias can arise from insufficient sampling, which becomes more prominent for emission events with shorter durations. As an example, their simulations of monthly sampling of sites with 1-hour duration events led to an average absolute percent error of 23% in annual emission estimates. Further, the study's Monte Carlo analysis showed an annual emission estimate constructed from monthly sampling of 1-month events have a 15% probability of having an error of >100%.<sup>77</sup> Recent findings from repeated, frequent overflights by aircraft have found that many large emission sources are intermittent. In the Permian Basin, Stokes et al.<sup>78</sup> reported that half of the tank battery sites (oil and gas production sites with liquid storage and handling equipment) that had emission rates of >10 kg/h during an initial aircraft overflight had much lower emission rates (<10 kg/h) when resampled a few days later.

Data from the commenter's deployment of continuous monitoring technologies in the field suggest that emissions from such intermittent emissions events are also substantial and may even be a dominant contribution to overall site emissions. These types of releases can result from process inefficiencies, such as faulty thief hatch systems causing emissions releases from a bad seal. For example, data from one site using continuous monitoring, displayed in the picture below, showed significant emissions from a process-related event that lasted 21 hours (caused by multiple attempts of plant engineers to start up a burner while the pilot flame was off). The picture also shows the signature of a small ongoing fugitive leak happening at the same time in one of the valves. Noteworthy is that the process event was 10 times larger in size than the leaking valve: [Timeseries plot showing examples of a process event and fugitive leak.]

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<sup>77</sup> Schissel, C.; Allen, D. T., Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates, Environ. Sci Technol. 2022, 9(12), 1063-1067, available at: <https://pubs.acs.org/doi/10.1021/acs.estlett.2c00731>.

<sup>78</sup> Stokes, S.; Tullos, E.; Morris, L.; Cardoso-Saldaña, F. J.; Smith, M.; Conley, S.; Smith, B.; Allen, D. T., An Aerial Field Trial of Methane Detection Technologies at Oil and Gas Production Sites, 2022, ChemRxiv:10.26434/CHEMRXIV-2022-G2MJT-V2.

Commenter (2340-Honeywell) states the figure below shows the recorded emissions with approximately a dozen Signal Scout detectors mounted on the tanks of a well-head operation over a period of 1 month. This shows that the emissions are not continuous, but are intermittent, with a duration typically of 12 hours. All large emissions (>10 kg/h) were positively matched with an activity at the site, such as a thief hatch opening or repair. A periodic inspection at the middle of the month likely would have missed this event or, if caught during the inspection, the operator would have missed an opportunity to reduce the emissions earlier by replacing the faulty seal to prevent the excess emissions.

Commenter (2340-Honeywell) goes further, survey-based studies indicate that large emission events account for the majority of total emissions:<sup>79</sup> [Plot with x-axis: Emission rate (kg/h) and y-axis: % of total emissions. Plot for well sites, tanks, pipelines, etc.]

Response II-5-174: EPA acknowledges the commenters' input. EPA recognizes the power of continuous systems to identify intermittent large events from ongoing maintenance events.

Comment: Commenter (2340-Honeywell) states continuous monitoring detection and characterization of the duration and magnitude of such releases will enable operators to better understand process inefficiencies that lead to such emissions and facilitate reduction strategies while improving their operations performance. These data will not only enable further reductions in emissions, but more accurate emission profiles and annualized inventories that facilitate the eventual adoption of quantitative emissions reduction targets and the ability to focus on more programmatic controls and improvements to address these preventable emissions.

Commenter (2340-Honeywell) states in addition to providing useful data to operators and regulators on intermittent emissions that would not otherwise be caught by periodic screening surveys, the failure to fully account for such emissions in FEAST modeling disadvantages the treatment of continuous monitoring in the regulatory framework. EPA explained in the preamble to the supplemental proposal that it used FEAST modeling to determine whether and how alternative periodic screening and continuous monitoring could provide equivalent emissions reductions to the BSER approach. EPA used FEAST modeling to establish the matrices for periodic screening, and to determine the action levels (based on simulated annual emissions) for continuous monitoring. If such limited duration, large emission events are substantial and not adequately accounted for in FEAST modeling, then EPA's equivalence analysis will underweight the value of continuous monitoring. Doing so will discourage the adoption of continuous monitoring and thereby perpetuate a lack of understanding of shorter-duration emissions events.

Response II-5-175: EPA acknowledges the commenters' input.

Comment: Commenter (2340-Honeywell) argues EPA should ensure that FEAST modeling does not self-perpetuate an unwarranted or "built-in" disadvantage for continuous monitoring in the

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<sup>79</sup> Daniel H. Cusworth, Riley M. Duren, Andrew K. Thorpe, Winston Olson-Duvall, Joseph Heckler, John W. Chapman, Michael L. Eastwood, Mark C. Helmlinger, Robert O. Green, Gregory P. Asner, Philip E. Dennison, and Charles E. Miller, *Environ. Sci Technol.* 2021 8 (7), 567-573, available at: <https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173>.



equivalence determination, which will limit EPA's ongoing understanding and data gathering necessary for such emissions control. To do so, EPA should (a) facilitate and encourage the deployment of continuous monitoring technologies by establishing more flexible parameters for their use as an alternative to BSER (as discussed above), and (b) ensure that it updates its FEAST modeling to better incorporate data on intermittent emissions events captured by continuous monitoring systems.

Commenter (2340-Honeywell) believes that FEAST modeling should be refined through the incorporation of continuous monitoring data showing significant emissions from shorter-duration events unlikely to be detected by periodic screenings. EPA should utilize data from continuous monitoring systems to update its FEAST modeling inputs and assumptions. The commenter's data indicate that current FEAST modeling suffers from a significant gap with respect to large emissions events of several hours that are common but not identified with intermittent inspection technology used to construct the model. This results in modeling that is currently biased in favor of periodic screening (*e.g.*, aerial survey) data because it does not account for the important advantages of continuous monitoring to address shorter-term emissions events that are an important part of the inventory. Incorporating data regarding limited-duration, intermittent emissions into FEAST modeling will facilitate the use of continuous monitoring technology (by removing a bias in favor of periodic screening) as well as improvements in process inefficiencies (*e.g.*, thief hatch releases) by enabling operators to better understand those releases. Use of such continuous monitoring technology to enhance the understanding of these emissions events will also better enable EPA to develop regulatory solutions to address them.

Response II-5-176: EPA acknowledges the commenters' input.

Comment: Commenter (2433-EDF *et al.*) states the FEAST model outputs depend on the emissions distributions used to conduct the modeling. In general, using a heavy-tailed emissions distribution—meaning one where a small number of large emission events represent a significant portion of the total—will result in a relatively greater effectiveness of frequent screening with less-sensitive technologies. With a less-heavy tailed distribution—meaning one consisting of many smaller leaks—more sensitive technologies that can detect those smaller leaks will be more effective. In FEAST, this means that OGI monitoring results in a greater effectiveness with a more normalized emissions distribution, while a technology like aerial monitoring results in a relatively greater effectiveness with a heavy-tailed distribution.

Commenter (2433-EDF *et al.*) notes while heavy-tailed distributions have been found across basins (and in all basins, a subset of emission events disproportionately contribute to total emissions), in most basins, the bulk of the emissions are still generated smaller leaks. Thus, capturing the large emission events is necessary but not sufficient and the approach, across basins, should capture the entire distribution of leaks. Because emissions distributions vary significantly by basin, ensuring that technologies can achieve equivalent reductions across basins requires using an averaged distribution that reflects both individually smaller (but collectively significant) leaks as well as super-emitters.

Commenter (2433-EDF *et al.*) states the default FEAST emissions distribution is based on five field measurement studies and contains all the leaks found in those studies. EPA excluded leaks

that would not be addressed through the proposed monitoring requirements and supplemented the default distribution with two more recent studies. In addition, EPA accounted for large, super-emitting events with data from Cusworth *et al.*, 2021. The default FEAST distribution categorizes emissions into leaks, abnormal vents, and permissible vents. Because permissible vents are not mitigated by LDAR standards, EPA properly excluded this category of emissions.

Commenter (2433-EDF *et al.*) continues, the resulting averaged emissions distribution aligns with the regulatory structure and accounts for equipment component leaks, tank leaks, and large emission events based on data from seven studies across diverse basins. The distribution also accounts for the intermittency of emissions because it is based on studies that consist of actual field observations and rigorous statistical analyses. Emissions captured in these studies are those that were present at the time of observation. The resulting snapshot in time of emissions includes some events that were emitting and some that were intermittent, thereby incorporating intermittency. These studies further address intermittency through statistical analysis.

Commenter (2433-EDF *et al.*) states, as should be expected, FEAST modeling shows that a higher survey frequency improves performance when super-emitters are taken into account, regardless of the intermittency. While intermittent events can be missed if their average duration is lower than the survey frequency, FEAST modeling also shows that the emission reductions from advanced technologies compared to OGI are directionally higher as the duration of the super-emitter events increases. This is because longer super-emitter events result in a larger contribution to total cumulative emissions from super-emitters, which can be mitigated even with higher detection threshold technologies. While it is true that more empirical data is needed to further characterize average duration of intermittent super-emitter events across different basins,<sup>80</sup> current FEAST modeling captures the impact of super-emitter distributions in terms of the contribution to total emissions. This allows FEAST to produce robust frequencies for both OGI and advanced technologies to achieve significant emission reductions. Because many emissions from oil and gas sources are intermittent, frequent monitoring with OGI, advanced technologies, or both is necessary to ensure adequate mitigation.

Commenter (2433-EDF *et al.*) states to better understand the potential implications that altering the duration parameter in FEAST could have on EPA's proposed frequencies and mitigation effectiveness generally, the commenter recreated EPA's modeling but adjusted the persistence of super-emitters.<sup>81</sup> EPA's modeling does not alter the duration parameter, but instead holds super-emitters constant like all other types of emissions in the model. The commenter remodeled the same detection thresholds used by EPA with the same input assumptions but altered the duration of super-emitters to 5, 15, 45, and 90 days. The commenter found that this sensitivity analysis would not impact equivalency, or the frequencies proposed by EPA in the matrices. Given the

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<sup>80</sup> Cardoso-Saldaña, *supra* note 169, at 20 (2022), ("There is also lack of data on the temporal characteristics of high-emitters, which is a very sensitive parameter. Future work should focus on obtaining information on duration of high-emitters and on root-cause analysis, which will be particularly relevant when doing LDAR modeling coupled with a process-based simulator that includes routine emissions and with a finer simulation temporal resolution.").

<sup>81</sup> See Arvind P. Ravikumar, Role of Intermittency in Methane Emissions Reduction (Feb. 2023) (included as Attachment J to the commenter's letter).

results of this sensitivity analysis, and for the reasons described, the commenter does not recommend that EPA alter the duration parameter for super-emitters in its equivalency modeling.

Commenter (2433-EDF *et al.*) states when the duration parameter is shortened for super-emitters, it results in fewer overall emissions and also in super-emitters making up a smaller fraction of total emissions. This means that more frequent screening (*i.e.*, monthly) detects and can therefore mitigate more super-emitters than less frequent methods (*i.e.*, quarterly). But because the overall contribution of super-emitters is significantly lower with shorter durations, the more frequent detections are less important to overall mitigation and do not impact equivalence. These results also underscore the need for an annual OGI pairing with the higher detection threshold technologies. With greater intermittency and lesser overall emissions from super-emitters, the annual OGI pairing becomes increasingly important for mitigating other types of emissions that then represent a larger portion of the total. Results of this modeling are displayed below, and the entire analysis is located in attachment J to the commenter's letter.<sup>82</sup> Figure 5 shows how the relative contribution of super-emitters to total emissions declines with greater intermittency.

[Figure 5 Total methane emissions by category bar chart]

Commenter (2433-EDF *et al.*) notes Table 9 below shows the effects on equivalency when the duration parameter is altered to account for intermittent super-emitters. It shows site-level emissions after quarterly OGI surveys and periodic screening surveys with three detection thresholds (with and without an annual OGI pairing) for three durations parameters (persistent, 90 days, and 15 days). As shown, the results do not support altering the frequencies proposed in EPA's matrices (equivalency condition shown in orange).

[Table 9 site level emissions with three detection thresholds for three duration parameters]

Commenter (2433-EDF *et al.*) states while it is important to understand the impacts of different intermittency assumptions on equivalence, the available data and modeling does not support revisiting the frequencies in EPA's proposed matrices. EPA's FEAST modeling is supported by seven different peer-reviewed studies based on field observations that incorporate intermittency and capture typical conditions. Absent explicit, peer-reviewed data characterizing intermittency that significantly affects the emissions distribution used in FEAST, additional modeling scenarios that alter the persistence parameter are not necessary and would have minimal impact on the outcomes. The commenter therefore recommends that EPA not alter the FEAST modeling underlying the proposed matrices. EPA should, however, assess the potential impact of intermittency based on data and information submitted during the comment period, such as that described above.

Commenter (2433-EDF *et al.*) adds numerous commenters have submitted modeling results, including Joint Environmental Commenters. In particular, some commenters have claimed, sometimes on the basis of their modeling results, that aerial screening technologies at lower

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<sup>82</sup> Id.

frequencies, like quarterly, can be equally effective as quarterly OGI.<sup>83</sup> This claim, however, is specific to certain basins or operations with a disproportionately high share of super-emitters. Because that is not the case nationally, it would be arbitrary for EPA to rely on basin- or operator-specific assumptions about emissions distributions. Doing so would likely reduce screening frequencies in higher-emitting basins, resulting in approaches that would not be effective in other basins with normalized emissions distributions. And while less frequent monitoring in higher-emitting basins may lead to greater percentage reductions than it would elsewhere, it will not lower emissions to a level commensurate with the rest of the country. Capturing super-emitters is necessary but not sufficient and overall performance should not be sacrificed by only focusing on capturing individual high-emitting events. Further, with full implementation of EPA's proposal, including repeated LDAR surveys, the prevalence of large emission events should be greatly reduced. If EPA's modeling included a too heavy-tailed distribution, it would result in a matrix that would quickly become outdated and ineffective as super-emitters are reduced.<sup>84</sup>

Commenter (2433-EDF *et al.*) states to illustrate the differences in mitigation effectiveness across basins, the commenter also conducted FEAST modeling of OGI, Aerial 1 (lower detection threshold with and without annual OGI), and Aerial 2 (higher detection threshold with and without annual OGI) using two basin-specific emissions distributions.<sup>85</sup> For a heavy-tailed distribution, the commenter used data from the Permian, and for a less-heavy tailed distribution, the commenter used data from the Marcellus. Both emissions distributions include recent data on super-emitters from the respective basins. The results show how different technologies perform in different basins and demonstrate how higher detection threshold technologies are far less effective in basins with more normalized distributions. This underscores the importance of EPA using a nationally averaged distribution to ensure equivalent reductions and account for the decreasing prevalence of super-emitters anticipated in coming years and with implementation of EPA's proposal. The results also underscore the need to ensure permissible technologies are sensitive enough to detect the significant fraction of total emissions--often the majority--that are caused by smaller emissions. Takeaways from the basin-specific modeling are summarized below.

[Table 10 Modelling Results in Marcellus and Permian by Category]

Commenter (2433-EDF *et al.*) states the equivalency modeling results from the Marcellus demonstrate that aerial technologies cannot achieve the same level of reductions as OGI when used at the same frequency. The addition of an annual OGI survey is particularly important under this scenario, as it helps reduce the smaller leaks below the detection thresholds of the aerial

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<sup>83</sup> See, e.g., Pioneer Natural Resources USA, Inc., Comments on Standards of Performance for New, Reconstruction, and Modified Sources and Emissions Guidelines for Existing Sources (Doc. ID. No. EPA-HQ-OAR-2021-0317-0820) (Jan. 31, 2022), <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0820>.

<sup>84</sup> EPA may consider addressing outlier situations through the AMEL process. However, for the reasons discussed in this section, any AMEL approaches should be time-limited, and EPA should continually revisit the underlying assumptions and update them for accuracy.

<sup>85</sup> Arvind P. Ravikumar, FEAST:US – Basin-level Modeling of LDAR Program for Methane Emissions Mitigation (included as Attachment K to the commenter's letter).

technologies. As shown below, quarterly OGI is more effective than aerial technologies in a basin with a more normalized emissions distribution.

[Figures 6 OGI Fugitive Emission Reduction % by survey frequency bar chart, Figure 7 Aerial 1 Fugitive Emission Reduction % by survey frequency bar chart, Figure 8 Aerial 2 Fugitive Emission Reduction % by survey frequency bar chart]

Commenter (2433-EDF *et al.*) notes the full results of this modeling are presented in attachment K and underscore the need for more frequent screening and, in some cases, an annual OGI pairing, in order to achieve equivalency across diverse basins. The results align with and support EPA's proposed matrices and annual OGI pairings.

Over the past two years, Commenter (2433-EDF *et al.*) has conducted FEAST modeling with different types of input assumptions, including using basin-specific emission distributions and the intermittency assumptions described above, as well as the nationally representative modeling submitted with our initial comments.<sup>86</sup> The key takeaways from this work include:

- Using rigorous and nationally representative emissions distributions is critically important—for EPA's section 111 standards, a nationally-averaged distribution is necessary to ensure advanced technologies deliver equivalent or better emission reductions across diverse basins.
- When super-emitters are less prevalent in the emissions distribution—as is the case in many basins already and should result more broadly from implementation of EPA's final regulations—higher-detection-threshold technologies are less effective.
- Altering intermittency assumptions through the duration parameter in FEAST has no significant impact on equivalence and reduces the overall contribution of super-emitters, thereby increasing the importance of OGI pairings with high-detection-threshold technologies.
- At higher detection thresholds, reductions eventually flatline even when frequency is increased—this is because a certain fraction of emissions cannot be detected or mitigated by these technologies.
- An annual OGI pairing can help address the fraction of emissions that fall below a technology's detection threshold but will not significantly increase total reductions in most cases; and
- Technologies with very high detection thresholds may not reliably achieve reductions equivalent to quarterly OGI, especially in the longer-term, and are therefore not suitable for regulatory deployment.

The results of the commenter's (2433-EDF *et al.*) modeling work, across a range of scenarios and with varied inputs, demonstrate that EPA's FEAST modeling and proposed matrices are robust and resilient to a range of sensitivities.

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<sup>86</sup> See Arvind P. Ravikumar, FEAST:US – Alternative LDAR Programs for Representative US O&G Production Facilities National Slides (included attachment L to 2022 Joint Environmental Comments, *supra* note 1).

Response II-5-177: EPA acknowledges the commenters' support of EPA's FEAST Modeling.

Comment: Commenter (2387-CSU) provides results of field observations suggesting that EPA's assumptions used for modeling purposes, do not reflect the behavior of intermittent emitters, large or small, in the field environment. This means that the modeling overestimates the effectiveness of OGI and AVO relative to continuous monitoring.

The commenter (2387-CSU) provides results based upon preliminary analysis of data provided by two continuous monitor solutions (Kuva and LongPath) that have been deployed on multiple facilities for extended periods. Detailed information on the study's findings can be found in the commenter's letter.

The commenter (2387-CSU) explains that two sets of simulated results were developed:

- What is the probability that the emitter would be detected during one year of OGI surveys?
- If detected sometime in 10 years, how long before the first detection?

These two results are multiplicative, as the second occurs only when the first is true: when detected if successful. Even for 10 years simulations, many simulated OGI survey programs never detected the emitter.

The commenter (2387-CSU) shows results for Kuva, where annual success rates range from 3.7% [0.16% to 12%] for annual surveys to 31% [1.2% to 78%] for monthly surveys. In remainder of simulated years, the emitter was never detected. Using the full 10-year simulation, when an emitter was detected, the time to make that detection is 5.2 [3.6 to 6.2] years for annual surveys, dropping to 2.8 [0.69 to 5] years for monthly surveys.

Results for LongPath show that annual success rates range from 32% [12% to 67%] for annual surveys to 98% [80% to 101%] for monthly surveys. These values were higher than the Kuva data for two reasons. First, the LongPath records start after the emitter is detected, *i.e.*, after the alarm protocol identified an emitter with some level of persistence. This biases the LongPath data toward longer duration emitters, which is clearly seen in the results. Second, LongPath's longer observation time at any one location (21 [13 to 37] minutes) sets a minimum emitter duration that is several times longer than Kuva's data (5.9 [1.9 to 11] minutes).

According to the commenter (2387-CSU), results in the two datasets clearly illustrate how sensitive detection simulations are to seemingly small variations in assumed duration – detection changes of nearly 8:1 for annual surveys and 3:1 for monthly surveys.

Using the full 10-year LongPath data simulation and considering only MC iterations where the emitter was successfully detected, annual surveys detected the emitter in 3 [1.5 to 4.4] years, dropping to 0.3 [0.12 to 0.66] years for monthly surveys. Actual detection timing by the CM solution is not in these data sets, as they start after the detection occurred.

The commenter (2387-CSU) notes that the current data sets lack sufficient information to determine the fraction of facilities emitting at any one time, which would be required to compare detections with the Cusworth *et al.* data set used in the attachment. However, it is likely that the intermittency shown here is representative of many large emitters detectable by aircraft.

Commenters (2333-LongPath, 2387-CSU) state intermittency should be included in modeling. Prior studies on intermittency of super emitters include Stokes *et al.*<sup>87</sup> and Wang *et al.*<sup>88</sup> The data collected by Kuva and LongPath validate intermittency data published in literature that indicate more than 90% of super-emitters are intermittent with a duration of multiple hours to a day.

Commenter (2387-CSU) states CM solutions detect emitters not commonly found by OGI or AVO surveys. The vast majority of the detections represented in these data sets were discovered first by the CM solution. The intermittency of the emitters likely made follow-up more difficult; personnel arriving hours to days after the detection were highly unlikely to see the emitter. However, operators found it useful to review timing and location data from the CM solution to assist with follow-up diagnostic. These (qualitative) observations suggest that, without the repeat detections by the CM solution to identify the time-domain pattern of emissions, follow-up is often challenging. Therefore, the value of near-continuous monitoring goes beyond one-time-per-emitter detections from survey methods. The commenter encourages EPA to positively weight the ability of CM solutions to detect highly intermittent emitters when calculating parameters in the proposed matrix.

Commenter (2387-CSU) states the emitters reported in this data may be due to process problems or to fugitive emissions. Since well pads include many cyclic processes, all types of emitters may exhibit intermittent behavior. Examples: A well pad where wells use plunger lift behave in a highly cyclic fashion – long periods with no flow, interspersed with short periods with high flow. If wells flow continuously, snap-acting dump valves on separators may produce similar cycling behavior. Emitters may also depend on interaction between multiple factors. For example, a pressure relief valve on a tank may vent only if liquid level in the tank is above some threshold and multiple wells/separators are flowing at the same time. Most of the data used here, and most detections in the Cusworth *et al.* super-emitter distribution, are likely due to abnormal process conditions - either control failures or excess emissions where controls are not required. The commenter encourages EPA to consider a wide range of emitter types in setting parameters for the proposed matrix. The current approach considering only narrowly defined fugitive emissions is not aligned with field experience.

Response II-5-178: EPA acknowledges the commenters' input. EPA agrees that the continuous and near-continuous methane monitoring systems are much better in identifying intermittent emission points as opposed to the periodic screening. EPA does not have sufficient information regarding the intermittency of these large events to necessitate changes to the FEAST modeling.

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<sup>87</sup> "Reconciling Multiple Methane Detection and Quantification Systems at Oil and Gas Tank Battery Sites" (Jan. 27, 2023), <https://pubs.acs.org/doi/10.1021/acs.est.2c02854?ref=pdf>

<sup>88</sup> "Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting", <https://pubs.acs.org/doi/full/10.1021/acs.est.2c06211> (Oct. 6, 2022)

### ***5.9.9 Proposed Requirements Discourage Use***

Comment: Commenters (2235-SLB, 2333-LongPath) state the proposed regulations contain many additional elements for continuous monitoring that complicate an operator's use of alternative screening technology, thus discouraging use of continuous monitoring technologies over the certainty of a prescribed approach for use of older technology. These additional elements do not relate directly to the proposed continuous monitoring technology itself but rather amount to requiring additional work unrelated to technology choice.

Commenter (2235-SLB) adds examples of such additional elements required for continuous monitoring beyond what is required for AVO and/or OGI fugitive emissions monitoring include: §60.5398(c)(2)(iii), §60.5398(c)(2)(vi), §60.5398(c)(2) (ix and x), and §60.5398(c)(6).

Response II-5-179 : EPA acknowledges the comment and EPA has made revisions to the continuous monitoring approach as detailed in Section X.B.2 and XI.B.2 of the preamble of the rule, specifically in regards to the accounting of background methane emissions from a site. EPA considers to the continuous approach as less onerous than the prescriptive fugitive monitoring approaches reliant on find and fix approaches. The continuous approach is less burdensome on what an owner or operator must do, and instead allows for an owner or operator to take the actions they need to do to maintain their emissions below the action-level.

Comment: Commenter (2333-LongPath) recommends that, at a high level, EPA consider how a standard will act in the context of a voluntary program to go “above and beyond” BSER OGI requirements, rather than how a requirement and standard would best be crafted in a vacuum (e.g., a regulatory program that requires continuous monitoring).

Commenter (2333-LongPath) highlights as EPA points out, diverse stakeholders are interested in how EPA can “promote and accommodate [the] development and use” of “these new tools for methane identification and quantification”. Because EPA has defined BSER as periodic OGI, EPA will need to avoid any regulatory requirements that may inadvertently disincentivize continuous monitoring and other advanced monitoring systems that go beyond that basic standard. Conscious effort, in the form of incentives and careful avoidance of inadvertent disincentives, will be needed to effectively promote and accommodate continuous monitoring.

Commenter (2333-LongPath) offers the following examples of what would stifle the use of an alternative monitor:

- Increased emission data reporting requirements.
- Increased reporting requirements in general.
- Lower Action Thresholds requiring action on smaller emissions.
- Action Thresholds (Levels) that do not account for process emissions.
- Action Levels and programs that have not been modeled directly in FEAST to assess equivalency.
- Standards that go beyond methane to require or account for VOCs where other alternatives do not.
- Requirements to act on emissions with higher frequency or in a shorter timeframe.



- Use of simulation models with overly optimistic parameterizations of AVO and OGI efficacy.
- More prescriptive or intensive “up-time” requirements, particularly for continuous monitors.
- More complex data operationalization, for example the use of multiple action levels
- A general lack of “incentives” to participate in a more comprehensive program.
- Lack of accounting for the added cost of follow-up under the super-emitter program for emissions that have already been addressed by continuous monitoring.

Response II-5-180 : EPA acknowledges the comment, the continuous approach is an alternative to the BSER, EPA has made some revisions in this approach as described in Section X.B.2 and XI.B.2 of the preamble of the final rule.

Comment: Commenter (2333-LongPath) strongly recommends that record-keeping requirements be aligned across advanced technologies and with OGI. From §60.5242b, operators will be required to record mass emission rate information about each fugitive emission source identified. However, in our reading of the proposal, periodic screening is subject to no such requirement. Requiring this level of data sharing of some technology classes and not others risk severely disincentivizing operator use of technologies for which much more detailed reporting on emissions is required. The commenter respectfully requests more information on why operators would be required to report more data on emissions with one technology compared with others. The commenter further requests that technologies with greater data capabilities, for example the ability to produce a valid mass emission rate, not be disincentivized by having a greater burden for record keeping and data transparency. Relatedly, the commenter requests more information on why operators would be required to report each methane mass emission rate reading determined by the system, and each daily average, 7-day, and 90-day mass emissions rate which was determined in accordance with 60.5398b(c)(5). In the supplemental proposal, continuous monitoring is voluntary. The commenter therefore respectfully suggests that requiring more intensive operator data transparency, record-keeping and data sharing than any other alternative could strongly disincentivize operator use of continuous monitoring.

Response II-5-181: EPA recognizes the input from the commenter, The recordkeeping and reporting for alternative technology required in the rule are consistent with what a federal, state, local, or tribal authority need to evaluate compliance with the applicable regulations.

Comment: Commenter (2333-LongPath) noted that, if the continuous monitoring system is administered through a third-party provider, contact information where the provider can be reached 24-hours a day be provided. This is a highly burdensome requirement for small businesses, such as LongPath, that operate systems for customers. The commenter has detailed service agreements in place with all operators, with extensive details on safety, insurance and other risks and liabilities. The commenter requests further information on why EPA would require a third-party provider to be reachable at night or over weekends, given that this would be extending beyond the agreements already made between the third-party and the site managers or operators.

Response II-5-182: In order for the continuous monitoring work practice to be equivalent to the fugitive emissions BSER, the continuous monitoring system must be able to provide data on an ongoing basis. This is why EPA included a maximum system downtime in the rulemaking. It is critical that owners and operators be able to contact third-party providers any time that the system goes down, otherwise they face the risk of being out-of-compliance with the downtime requirement.

EA recognizes that not all third-party providers may not be readily available 24-hours a day, but we consider it important to maintain this requirement from the proposed rule.

#### ***5.9.10 Corrective Action/Timeline***

Comment: Commenter (2428-API) supports timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416. The commenter supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. The commenter believes an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. The commenter offers the following recommendations (more details are provided in the commenter's letter):

- The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.
- EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.
- EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s).
- The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.

Response II-5-183: EPA recognizes the commenter's input. EPA has revised the final rule for continuous monitoring as described in Section X.B.2 and XI.B.2 of the preamble of the final rule. EPA has provided the owner or operator the flexibility to take the appropriate measures when conducting the investigative analysis.

Comment: Commenter (2348-EWTC) states an appropriate deadline for corrective actions should be uniform across all monitoring methodologies. If a deadline is lower than the super emitter threshold, it should be within 45-day window. Super emitters should be addressed as quickly as possible after determining the root cause of the event. It is important to determine the typical timeline in the industry to assess root cause, and to establish a standard.

While commenter (2348-EWTC) understands that corrective action should be taken to eliminate a leak once discovered, treating technologies equally in this manner may not be appropriate (except for super-emitters). A continuous monitoring device, for example, provides earlier notice

of emerging fugitive emissions that may/will deteriorate over time; continuous monitoring also detects periodic emission events that are less likely to be discovered by a quarterly or semi-annual inspection regime.

Response II-5-184: EPA acknowledges the commenter's input; EPA has provided more flexibility for continuous monitoring in part due to the lower action-levels and that these systems have the ability to measure the intermittency of an emission source. This program is designed to only trigger action when the emission rates exceed a rate greater than what is expected for the BSER program, however we expect owner or operators to continuously repair any excess emissions sources, so they maintain their rates below the action-levels.

Comment: Commenter (2333-Longpath) strongly urges the EPA to find ways to incentivize operators to use continuous monitoring, and not the reverse. Most periodic survey monitors commercially available today do not provide notification of an emission to an operator within 5 days. This means that these technologies are not capable of enabling an operator to make an initial corrective action within a 5-day timeframe. Therefore, the commenter respectfully suggests that these time frames be made more technology neutral.

Response II-5-185: EPA acknowledges the commenter's input; EPA considers the flexibility associated with the flexible work practices under the continuous monitoring to be an adequate incentive to use continuous monitoring.

#### ***5.9.11 Cost of Continuous Monitoring***

Comment: Commenter (2325-Aclima) states the annual per-well cost of complying with the proposed rule is estimated to range from \$2,490 for biennial OGI monitoring to \$8,140 for monthly OGI monitoring at the average well site. Rolled up, that's between \$54,780 to \$179,080 per year for the average owner of 22 wells. Networked small sensor technologies can be implemented at a fraction of these costs, with the enhanced benefit of continuous, networked monitoring across all wells.

Response II-5-186: EPA acknowledges the input from the commenter. The use of continuous monitoring in the rule is an alternative to the BSER and not a requirement, therefore EPA has not considered the cost of these systems in this rule.

Comment: Commenter (2440-NNS) notes compared to state-of-the-art continuous monitoring systems, the proposed BSER of bimonthly AVO inspections and quarterly OGI inspections provides neither the greatest emissions reduction, nor does it provide the most economical solution. Continuous monitoring technology provides immediate detection of leaks and the greatest reduction in emissions for as little as \$1600 per year for Major Production sites on a Total Cost of Ownership basis. This price includes hardware installation, automated, continuous monitoring software and support, all required maintenance, automated leak notifications, visualization of the leak location via computer, tablet or phone and automated reporting of emission statistics. The cost of CP-CMS is much less than Table 18 at \$4232 the annual cost for this monitoring.

Commenter (2440-NNS) states from an emissions reduction perspective, this will reduce average leak detection times from 45 days to less than one day for continuous monitoring systems. From a cost point of view, it compares well with the figures in Tables 10 and 15 at \$660 for quarterly AVO inspections.

Commenter (2440-NNS) encourages the EPA to also allow continuous monitoring technology solutions as a BSER for low production assets. The commenter recognizes that the performance of any specific continuous monitoring solution depends on verification of the performance and would agree that the regulations need to account for such validation.

Response II-5-187: EPA acknowledges the input from the commenter. The use of continuous monitoring in the rule is an alternative to the BSER and not a requirement, therefore EPA has not considered the cost of these systems in this rule.

### ***5.9.12 Root Cause Analysis***

Comment: Commenter (2226-Thermo Fisher) notes continuous monitoring technologies lead to greater, more timely emission detection. EPA proposes an alternative work practice standard, in which a root cause analysis is undertaken when the methane emissions rate exceeds certain levels at the boundary or fenceline of a facility to account for upwind or meteorological effects. This requires technologies that quantify site-level methane emissions rates at a detection level an order of magnitude less than the proposed action level and produce a valid mass emissions rate at least once every twelve hours. The commenter supports the inclusion of continuous monitoring approaches, as the commenter agrees this type of measurement provides better temporal resolution to catch a leak when it begins.

Commenter (2226-Thermo Fisher) expresses that in some cases, a combination of technologies for measuring and monitoring methane emissions is the best solution to ensure the detection of all emissions is possible. For example, a combination of a toxic vapor analyzer and OGI would provide ample coverage. It is worth noting adequate training needs to be readily available for OGI operators. OGI cameras have variations in their effectiveness at finding leaks based on the individual operating them. The accuracy of data collected using OGI cameras relies on good monitoring practices. The EPA should recognize that the data collected can be vastly different based on the individual's skill set and thus can make gas leaks difficult to quantify accurately. The commenter supports the EPA for advocating for continuous monitoring because it would ensure measurements are taken more often.

Response II-5-188: EPA acknowledges the support and input from the commenter.

Comment: Commenters (2298-Pioneer, 2363-CEMC, 2402-DGCC, 2428-API, 2448-Project Canary) have concerns that the investigation takes the form of a "root cause analysis" and ask EPA to clarify what is required for a "root cause analysis." EPA requires root cause analyses for any detections identified with advanced technology but not with OGI nor the compliance standards for non-fugitive emission equipment. Commenters (2177-Southern Ute, 2238-Southeastern Ohio Oil and Gas Association (SOOGA), 2298-Pioneer, 2363-CEMC, 2402-DGCC, 2428-API, 2448-Project Canary) argue the term "root cause analysis" is a term of art

under other non-EPA regulatory programs and is associated with a very specific and extensive set of analysis requirements, which the commenters believe would not be appropriate for the contexts addressed in the NSPS OOOOb and EG OOOOc regulations. Commenters (2177-Southern Ute, 2238-SOOGA) add a root cause analysis is overburdensome.

Commenters (2177-Southern Ute, 2363-CEMC, 2402-DGCC, 2428-API, 2448-Project Canary) request that the term “investigative analysis” should replace “root cause analysis.” If the EPA intends that such an analysis have particular elements, it should specify them.

Commenters (2298-Pioneer, 2428-API) continue, there is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule. This could potentially involve a months-long endeavor and discourage operators from choosing to comply using advanced technology. Therefore, the commenters suggest that EPA should specify more precisely what is required to identify any process failures resulting in emissions and adopt a more accurate term such as “investigative analysis”, “causal examination”, or “proximate cause” and define the term in the Final Rule, specifying more precisely what is required to identify any process failures resulting in emissions.<sup>89</sup>

Response II-5-189: EPA acknowledges the commenters’ input, as explained in Section X.B.2 and XI.B.2 of the preamble of the rule, EPA has revised the rule to remove the “root cause analysis” language in favor for “investigative analysis”.

Comment: Commenters (2333-Longpath, 2399-GPA, 2428-API) suggest that references to “root cause analysis” be amended to “investigative analysis.”

Commenter (2399-GPA) adds that EPA does not define what is meant by a “root cause analysis” or what documentation it expects such an analysis to produce. As discussed in more detail below, a root cause analysis involves a formal systematic investigation, using multiple potential methodologies, into the potential causes of an incident that identifies corrective actions to reduce the probability of similar future incidents. See Section VII, *infra* (discussing root cause analysis requirement for the super-emitter program). Root cause analyses typically involve several specialized team members and take far longer than the five days specified in the proposed regulatory text. EPA has not considered the costs, or the time required to perform a formal root cause analysis. The commenter recommends that EPA use a more generic and appropriate term, such as “evaluation,” in describing the examination and determination described in the proposed regulatory text. Even as to an evaluation, EPA should allow a minimum of 30 days to make the necessary assessment. If a “root cause analysis” is retained, EPA should allow at least 90 days to complete that more formal and complex analysis.

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<sup>89</sup> 87 Fed. Reg. 74741; this recommendation is in response to EPA 's request for comments: "The EPA is soliciting comment on the proposed requirements for the root cause analysis and corrective action, the timeframes for conducting these activities, and the requirement for corrective action plan submittals." 87 Fed. Reg. 74745.

Response II-5-190: EPA acknowledges the commenters' input, as explained in Section X.B.2 and XI.B.2 of the preamble of the rule, EPA has revised the rule to remove the "root cause analysis" language in favor for "investigative analysis".

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) add that when advanced technologies such as CEMS, are utilized, desktop evaluation will usually suffice to identify the cause of some types of exceedances, negating the need for onsite AVO or OGI follow-up inspections. Initiating an investigative analysis in response to the exceedance of an applicable action level may be conducted as follows:

- Desktop or Remote investigative analysis. A desktop or remote investigative analysis could include:
  - verbal or written communications with onsite personnel to verify the cause of an exceedance,
  - review of remote sensing or parametric data which could indicate the cause of the exceedance,
  - or other data acquisition methods which can adequately determine the source of the emissions and ensure the cause of emissions has been resolved.
- If the desktop or remote investigative analysis does not identify the cause of the exceedance, then the operator should conduct either:
  - Onsite AVO investigative analysis. If the source and cause of the emissions resulting in an exceedance of an action level cannot be determined through a desktop or remote investigative analysis, the owner or operator may perform an AVO investigative analysis to determine the cause; or an OGI camera or Method 21 investigative analysis. If the source and cause of the emissions resulting in an exceedance of an applicable action level cannot be determined through either of the previous methods, the owner or operator shall perform an OGI camera or Method 21 inspection. The inspection can be limited in scope, based on any source localization data from the continuous monitoring system, narrowing the area where the investigation should be performed to the area most likely to be the source of the leak.

Comment: Commenter (2307-Qube) suggests that the EPA consider a tiered approach to the root-cause analysis as many emissions events can be diagnosed using the data from the continuous monitoring system before sending someone to site, and suggest the following approach:

- Remote diagnosis of the emissions event using the continuous monitoring system
- Follow-up with an AVO or OGI inspection if the contributing emissions cannot be diagnosed remotely

In the commenter's (2307-Qube) opinion, continuous monitoring systems are one of the most effective tools for verification of repairs. This is because following a repair, the operator can immediately see a reduction in the quantified emissions at a site. In general, the commenter believes that seeing an emissions reduction following a repair at a facility has been one of the key reasons operators are adopting continuous monitoring technology.

Response II-5-191: EPA acknowledges the commenters' input. EPA has does not prescribe what investigations an owner or operator must conduct, and instead relies on the owner taking whatever action is necessary to get mass emission rate below the action level, as measured by the continuous emissions monitoring system.

### ***5.9.13 Follow-up and Continuous OGI***

Comment: Commenter (2405-Bridger) notes although the Proposed Rule requires follow-up OGI screening for emissions detected during periodic screening,<sup>90</sup> equivalent requirements are not delineated for the alternative continuous monitoring program, which damages the intended technology agnostic nature of the rule. Site-level emission action levels for the continuous monitoring alternative approach could be triggered by an aggregate set of emissions, and OGI screening would help locate individual emission sources and make sure the aggregate methane flux is accounted for. To reduce the OGI follow-up requirement to only what is necessary to reduce emissions, the scope of OGI surveys should correspond to the localization capabilities of the continuous monitoring method (as was recommended for the periodic screening approach in Comment 1.2). Continuous monitoring systems localize emissions with different degrees of precision, which has been characterized by independent researchers.<sup>91</sup> In order for the EPA to continue developing a consistent, practical, and technology agnostic framework to use advanced methane sensing technologies for emissions monitoring, the commenter urges the EPA to include the same OGI follow-up requirements for the continuous monitoring alternative approach as for the periodic screening alternative approach.

Response II-5-192: EPA recognizes the commenter's input; he has chosen not to require prescriptive requirements for follow-up actions when an action-level is exceeded. Because the standard is based on a whole site emission rate, any action which gets an emission rate below the action level is adequate.

Comment: Commenters (2363-CEMC, 2421-Teledyne, 2448-Project Canary) note that the EPA is aware of other continuous monitoring systems using technologies that are not designed to quantify a site-level methane emissions rate (e.g., camera-based continuous monitoring systems). While the EPA believes these systems could be useful in a methane mitigation program, they are not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions, which is the basis for the equivalency demonstration of the proposed alternative continuous monitoring approach.

Commenters (2363-CEMC, 2448-Project Canary) are aware of camera-based continuous monitoring systems that are in use today or under development. As with other types of surveying and monitoring technologies, the commenter anticipates rapid innovation and improvement in their capabilities. Given the developments in this area, the commenter sees no rationale for the EPA to codify a categorical preclusion of any consideration of such technologies under the

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<sup>90</sup> It is unclear if FEAST modeling used to investigate equivalence involved OGI follow-up. In the 'RS Run Script plane.txt' python script provided in the docket, the continuous monitoring LDAR program object, 'cont\_monitor' did include OGI in the 'dispatch\_object' field. Regardless, OGI follow up was not specified in the Proposed Rule.

<sup>91</sup> Bell, C., Ilonze, C., Duggan, A. & Zimmerle, D. Performance of continuous emission monitoring solutions under single-blind controlled testing protocol. ChemRxiv (2022) doi:10.26434/chemrxiv-2022-4hc7q-v2.

alternative test method provisions—whether as periodic surveying technologies or continuous monitoring systems. Such a preclusion is inconsistent with the policy objective of promoting technology innovation that is the foundation of the rest of the Supplemental Proposal.

For these reasons, commenters (2363-CEMC, 2448-Project Canary) respectfully recommend that the EPA withdraw this preclusion and instead evaluate proposed camera-based continuous monitoring systems on a case-by-case basis under the alternative test method provisions.

Response II-5-193: EPA agrees that camera-based solutions could be used as periodic screening technologies and has revised the final rule as detailed in Section X.B.1 and XI.B.1 to allow their use for those purposes.

Comment: Commenters (2235-SLB, 2340-Honeywell) request that EPA not generically disparage categories of technology<sup>92</sup> such as cameras in its proposed rule based on past information. Technology advances and adaptations continue to progress. While EPA's comment that camera technology is not capable of quantification may have been intended to refer to well-known OGI cameras used for decades, it could inadvertently discourage use of all camera technologies as advanced alternative technologies, now and in the future. The commenters request EPA not categorically exclude a promising and suitable type of technology from use based on the limitations of past examples of that technology genre.

Commenter: (2235-SLB) indicates that new camera and camera-combined technologies do exist that are capable of not only providing imaging but also quantifying emissions, thus satisfying the requirements for continuous monitoring technology.<sup>93</sup> Current state-of-the art camera systems, such as lidar-based gas imaging cameras, available from SLB and QLM, have been shown in multiple independent trials and evaluations (including at the METEC facility in 2022) to be capable of very accurate detection, localization and quantification of methane flow rates at great distances. When such a lidar system is deployed at an appropriate vantage point at an O&G site, the lidar camera, mounted on a 360-degree rotating stage, is capable of continuously detecting and quantifying emissions from all equipment or emissions points within radius of hundreds of feet and at detection levels satisfying the requirements for continuous monitoring technology. As such, the emissions of individually measured emission points can be summed to produce a continuous and highly accurate measurement of the total site emissions. Furthermore, these lidar cameras can also be mounted on such a site to image and quantify the entire down-wind plume that would be comprised of an aggregation of all the individual emission points on the site. For these reasons, currently available lidar-based imaging cameras are indeed suitable for the proposed alternative continuous monitoring approaches.

Response II-5-194: EPA recognizes the acknowledges the commenter's input.

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<sup>92</sup> When the EPA states that camera-based continuous systems are not suitable for proposed alternative continuous monitoring approach (Fed Reg 87, 74745 Dec 6, 2022), the commenters argue it is overlooking recent developments in advanced camera technology that do provide means to quantify site emissions and thus are suitable for continuous monitoring applications.

<sup>93</sup> See for example [www.qlmtec.com](http://www.qlmtec.com).



Comment: Commenter (2340-Honeywell) cites the following text from the proposal preamble:

EPA is aware of other continuous monitoring systems using technologies that are not designed to quantify a site-level methane emissions rate (*e.g.*, camera based continuous systems). While the EPA believes these systems could be useful in a methane mitigation program, they are not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions, which is the basis for the equivalency demonstration of the proposed alternative continuous monitoring approach.

Commenter (2340-Honeywell) indicates that this statement regarding camera-based monitoring systems is inaccurate. To be considered a continuous monitoring system, the proposed supplemental rule provides that “the system must produce a valid mass emissions rate (*i.e.*, kg/hr) from the site at least once every twelve hours.” Rebellion GCI cameras provide monitoring of fugitive emissions components at much greater frequencies than once every 12 hours. Moreover, Rebellion cameras are able to detect the gas type, location, plume direction, size, and concentration, thus providing a “valid mass emissions rate.”

Commenter (2340-Honeywell) believes that EPA should clarify in its final rule that, contrary to the preamble to its supplemental proposal, camera-based systems are capable of quantifying site-level methane emissions on a continuous basis. EPA should further note that it expects such systems to qualify as alternative continuous monitoring systems under the rule should they be capable of meeting the technology requirements.

Commenter (2421-Teledyne) responds to how camera based continuous systems, like continuous OGI solutions, could fit within the alternative continuous monitoring approach, what action levels should be applied to a non-emission rate based continuous monitoring system, and data to support those action levels in order to conduct an equivalency demonstration. Camera based solutions that provide the ability to quantify each emission event can easily be used in aggregate setting to provide site level emissions, which is the basis for equivalency demonstration. In addition, these solutions are unique in that they can also assist an operator in providing situational awareness of the emission event, which most other periodic or continuous solutions cannot. With camera-based solutions, specifically continuous OGI solutions, an operator can evaluate the event via a recorded event or live feed to understand if an event is a true emission or an operation emission, or vent situation, that may happen to ensure the safe operation of the facility.

Commenter (2421-Teledyne) adds, the EPA solicited comment on whether a different type of approach should be used for these camera-based continuous monitoring systems, and if so, what that approach would look like and how equivalency could be demonstrated between the approach and the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. It is recommended to separate continuous OGI technologies as they are unique and should be not coupled with fixed sensor for continuous monitoring or large-scale periodic monitoring technologies. This technology has similar minimum detection levels as periodic monitoring at the distances they are applied but provide a very unique result as the output is more aligned with the continuous technology solutions,

instead of larger times between inspections for periodic technologies like monthly, quarterly or semiannually.

Response II-5-195: EPA acknowledges the commenters' input, the criteria for the alternative continuous monitoring approach are performance-based and there isn't a limit on the technology used so long as a site-level emission rate can be determined. Any entity may petition for an alternative test method as described in Section X.B.3 and Section XI.B.3 of the preamble of the rule.

Comment: Commenter (2336-Kuva) believes EPA should regulate camera based continuous monitoring systems like camera-based solutions used for plane surveys as a screening solution.<sup>94</sup>

Commenter (2336-Kuva) supports EPA's approach of enabling owners and operators to use advanced technologies through a performance-based matrix based on inspection frequency and a probability of detection-based sensitivity. The proposed matrix, combined with alternative test methods, can provide operators and technology developers with well-defined requirements to use a technology for compliance. The commenter urges EPA to approach the classification of technologies into continuous or screening with a technology neutral approach and not assign any solution to any one of these two regulatory pathways.

Commenter (2336-Kuva) states the screening matrix approach lends itself equally well as the basis for an alternative test method for camera based continuous monitoring systems as it does for camera-based solutions used for plane-based surveys. Both plane-based and stationary cameras have the same advantage in that they can:

- Visually pinpoint emissions to their source.
- Distinguish permitted emissions (*i.e.*, compressor methane slippage, maintenance activity) from abnormal emissions.
- Enable root cause analysis of process malfunctions by analyzing time-stamped emissions data together with time-stamped process control data.

According to Commenter (2336- Kuva), camera based continuous monitoring systems have the added benefit that they are ideal in conducting root-cause analysis of intermittent super-emitters. Recent publications have shown that more than 90% of super-emitter events have a duration of

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<sup>94</sup> This comment is in response to EPA's question: "The EPA is aware of other continuous monitoring systems using technologies that are not designed to quantify a site-level methane emissions rate (*e.g.*, camera based continuous systems). While the EPA believes these systems could be useful in a methane mitigation program, they are not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions, which is the basis for the equivalency demonstration of the proposed alternative continuous monitoring approach. That said, the EPA solicits comments on how these types of systems could fit within the alternative continuous monitoring approach, what action levels should be applied to a non-emission rate based continuous monitoring system, and data to support those action levels in order to conduct an equivalency demonstration."

less than 24 hours.<sup>95</sup> The commenter has confirmed these findings in an analysis of its own camera installations in five basins.

Commenter (2336- Kuva) adds that camera-based continuous monitoring solutions are an established technology class and both the Kuva camera and other cameras have been well studied in 3rd party blind testing.<sup>96</sup> The commenter proposes to EPA to treat camera-based continuous monitoring systems based on the same detection limits under the matrix as proposed under the alternative screening matrix while allowing for flexibility in the alternative test method application (see discussion below). Camera based continuous monitoring systems may be used within the most frequent inspection frequency available (currently monthly).

Commenter (2336- Kuva) notes that for purposes of complying with the supplemental proposal and in order to prevent “cherry picking” of results stationary cameras may be required to conduct a monthly screening at the beginning of each month as soon as sufficiently favorable weather conditions are present, *i.e.*, as soon as all fugitive components, covers and CVS can be covered within the specified operating envelope of the given continuous camera system. This screening will be recorded as the official screening and stored as per EPA’s applicable record keeping requirements. As long as a once-a-month screening frequency is maintained the alarm criteria for a continuous camera can be the same as for a plane-based inspection, *i.e.*, a single image of detected gas constitutes an alarm. The alarm response for camera-based continuous monitoring solutions should be equivalent to plane-based screening with cameras and should be appropriate relative to the detected emissions.

To ensure that the rule is technology neutral, Commenter (2336- Kuva) urges EPA not to include greater uptime or response requirements for continuous cameras than for any other screening solution. If a technology can detect more frequently than required in the periodic screening matrix, that should not create additional (more frequent) response requirements than would apply to an owner or operator deploying OGI or other periodic screening technologies. While a company may use a technology that collects emissions information more frequently than monthly, the obligation should be to demonstrate compliance with fugitive emission requirements no more frequently than the frequency required by the matrix based on the application detection threshold for the technology.

While this once-a-month screening at the beginning of a month is used to comply with the requirements of the screening matrix, Commenter (2336- Kuva) expects that operators will want to operate any stationary camera continuously (outside of regulatory compliance obligations) for the following reasons:

- Fast detection of super-emitters as soon as they are created in order to prevent detection under EPA’s 3rd party super-emitter program;

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<sup>95</sup> See table 5 in Wang et. al. “Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting”, <https://pubs.acs.org/doi/full/10.1021/acs.est.2c06211> (Oct. 6, 2022).

<sup>96</sup> See for example testing of 5 cameras in Bell, et al. “Performance of continuous emission monitoring solutions under single-blind controlled testing protocol”, <https://doi.org/10.26434/chemrxiv-2022-4hc7q-v2>

- As part of compliance with requirement for differentiated gas or oil certification;
- As part of compliance with future Methane Fee rules; and
- In order to conduct root-cause-analysis on detected emissions.

Commenter (2336-Kuva) argues stationary continuous cameras are to be installed in accordance with a vendor specific work-practice. Such work practice may include a requirement for an installation such that the camera provides line-of-sight to for example 80% or 90% of fugitive components, covers and CVS at a site. In order to provide for equivalent detection performance other parameters of the continuous camera such as increased screening frequency (beyond monthly), a full probability of detection curve and distance dependent detection limits may be considered as part of the alternative test method application via vendor specific FEAST modeling.

Response II-5-196: EPA agrees that camera-based solutions could be used as periodic screening technologies and has revised the final rule as detailed in Section X.B.1 and XI.B.1 to allow their use for those purposes.

#### ***5.9.14 Test Under Field Conditions***

Comment: Commenter (2340-Honeywell) indicates the approval process for alternative test methods should account for the various factors that may affect the accuracy and statistical certainty of the emissions measurement at particular detection thresholds. This is for two main reasons: to ensure that (a) applicants for approval of alternative monitoring systems are being evaluated on an even playing field, and (b) the approved monitoring systems are accurate as applied in the field.

Commenter (2340-Honeywell) recommends that EPA adopt a flexible standard for the use of continuous monitoring technologies that is based on the probability of detection of a leak of a given size. This would not only facilitate the adoption of continuous monitoring systems but would also hold each system's measurements to a common baseline confidence level to ensure accuracy. Various field conditions can affect the ability to detect/measure methane at a particular emissions rate and the statistical confidence of that measurement. This is particularly the case with regard to the assumptions and data points that factor into the algorithms to convert concentration readings (in ppm) to emissions rates (in kg/hr).

Commenter (2340-Honeywell) says that regardless of whether EPA adopts the commenter's proposal to base the continuous monitoring minimum detection requirement off of a probability of detection, the final rule should ensure that the alternative test method approval process requires applicants to establish and independently verify such metrics for their technologies under field conditions.

Commenter (2340-Honeywell) notes that the proposed supplemental rule already calls for applicants to submit supporting information verifying that their technology can meet the applicable detection thresholds in the field, as well as establish data quality objectives to ensure

detection thresholds are being met.<sup>97</sup> The commenter further notes that EPA has likened the proposed framework for continuous monitoring to the NESHAP fenceline monitoring work practice.<sup>98</sup> The NESHAP fenceline monitoring work practice similarly prescribes procedures for validating an alternative test method according to “Method 301.”<sup>99</sup> EPA has not clarified, however, whether it intends to use Method 301 or a similar procedure for the alternative test method approval process in the proposed supplemental methane rule. As explained above, several continuous monitoring technologies, including Honeywell’s, are deployed within the fenceline and in close proximity to the fugitive emissions source, in contrast to the NESHAP work practice. As such, Method 301, developed for fenceline monitoring test method approval, may not be appropriate in the context of inside-the-fenceline technology used for methane detection. Honeywell recommends that EPA instead consider the use of an independent third-party validator with experience in continuous methane detection technology, such as METEC, to validate the capability of a supplier’s continuous monitoring solution in terms of the detection sensitivity at a certain probability level.

Response II-5-197: EPA acknowledges the commenters’ input; EPA has revised the requirements for submitting an alternative test method for advanced methane measurement as described in Section X.B.3 and Section XI.B.3 of the preamble of the rule.

Comment: Commenter (2394-Earthworks) argues field implementation of CEMs provide unique challenges that are not addressed in current controlled studies and make them unreliable for detecting pollution events and/or identifying the source of pollution. Certainly, there is evidence that some CEM test methods could meet the EPA’s proposed detection limit (1.2 kg/hr for well only and 1.6 kg/hr for all others); however, this evidence comes from controlled experiments which do not and can never replicate field conditions.

Currently, Commenter (2394-Earthworks) is not aware of any examples of blind studies which provide evidence of any CEM detection capabilities in the field. Their own investigation of monitors in the field show that critical field decisions have the potential to render certain CEM technology virtually ineffective.

Commenter (2394-Earthworks) notes Colorado has recently introduced rules that require operators to submit and undertake an Air Quality Monitoring Plan using CEMs during pre-production and early production to detect VOC and/or methane pollution. Over the course of seven months in 2022, Earthworks OGI operators conducted a survey of sites in Colorado that were using CEMs under this new rule. In our 77 site visits during that period our OGI cameras detected 22 separate pollution events. These pollution events varied in size (small leaks to super emitter events), source (drilling equipment, tanks, ECDs, etc), and length of documentation (average each event lasted at least 15 minutes). However, according to operator records submitted to the Colorado Department of Public Health, the CEMs failed to detect any of the 22 events.

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<sup>97</sup> See 87 FR 74,702, at 74,746.

<sup>98</sup> See 87 FR 74,702, at 74,744, n. 97.

<sup>99</sup> See 40 CFR § 63.7(f).

Commenter (2394-Earthworks) believes while this regulatory framework differs from the EPA's proposed process, it is still one of the few opportunities for the public to investigate how CEMs work in the field. Our study sample represented CEMs from four different manufacturers and countless implementation variations, yet the results were all the same: CEMs did not detect the pollution present at the time of our OGI survey.

Response II-5-198: EPA acknowledges the commenters' input; EPA's continuous monitoring approach is based on a site-level emission rate instead of an individual component leak definition. It is possible, an OGI survey or a site with a continuous system installed could identify emissions, but so long as the site-level emission rate was less than the action level, no additional action is required.

Comment: Commenter (2394-Earthworks) states given CEMs sensitivity to weather, reliance on internet connection, power supply, frequent maintenance, it is not surprising that on average they perform less reliably in the field compared to controlled environments. However, the commenter's survey also suggests that there are many other factors to consider. The commenter states nearly all of the sites visited had set up their CEMs in a way that likely reduced their capabilities. For example, Project Canary often cites studies from Colorado State University to show the capabilities of their Canary-S monitors. Those tests are conducted with a system of eight monitors placed 30-230 feet from pollution sources. In comparison, the sites visited with Canary-S monitors had three to four monitors, which were never closer than 150 feet to pollution sources and often much farther than that. The commenter argues these significant variations were not addressed by the operators, the CEM manufacturers, or the regulatory agency. These decisions were not justified by research either. The commenter also found that operators had intentionally placed monitors behind barriers such as sound walls and this placement was approved by the CDPHE. Placing sensors behind barriers can prevent them from detecting any pollution. Again, these decisions were not supported by any evidence.

Commenter (2394-Earthworks) has collected footage of methane for nearly a decade and this footage consistently shows methane rising as it moves from sources that are commonly tens of feet above the ground. Often CEMs are placed on poles that rise just six feet above the ground. This means there is a very low chance they would pick up even large events, and almost certainly would not pick up small but persistent releases.

Commenter (2394-Earthworks) argues even if placed properly in the path of methane pollution these monitors cannot be relied upon for accurate data without frequent calibration and still may suffer from malfunctions with the slightest changes in weather, small disruptions in power supply, loss of capacity to upload data, and other minor adjustments. Are companies going to pay for that frequent maintenance? With this level of maintenance, it would likely be more cost effective and accurate to perform LDAR with OGI cameras.

Response II-5-199: EPA recognizes the commenter's input. EPA has included requirements in the final rule to ensure that technology that has been approved by the EPA for use of continuous monitoring must be operated in the manner defined by the approved alternative test method discussed in Section X.B.3 and XI.B.3 of the preamble of the final rule. Likewise, EPA also

includes specific QA/QC that must be met for the continuous monitoring systems that are detailed in Section X.B.2 and XI.B.2 of the preamble of the final rule.

Comment: Commenter (2346-Encino) notes methane intensity over a year and action levels are more of a regulatory threshold. For example, fluid dynamic limitations and adiabatic expansion (thermodynamic variables) can cause inaccuracies when testing thermally dependent technology as there would be diminished or nonexistent plume detection when tubes are used for technology evaluation (thermal equilibrium diminishes signal quality – a phenomenon that is almost non-existent under authentic operating conditions/scenarios). Accordingly, there needs to be procedures set forth that allow for across-the-board qualification of different monitoring systems that properly mirror a scenario of the most common leaks. These procedures could be CMS-specific testing protocols that discourage tube release, which would eliminate detection limitations caused by non-representative flowrates and adiabatic expansion in tube-based gas sample testing programs which are not representative of operational environments.

Commenter (2346-Encino) states inclusion of the development of site-specific MDLs for any technology used to support this program, which includes meteorological, geographic, and environmental factors, is appropriate. Site specific action levels, where actual emissions are favored over emission factors due to factor uncertainty and improper duration of events (temporal attributes), are beneficial for tracking intermittency and duration of events, thereby, providing a more accurate temporal representation.

Response II-5-200: EPA acknowledges the commenter's input.

#### ***5.9.15 Consider Funding/Support of Continuous Monitoring***

Comment: Commenter (2428-API) recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, the commenter urges EPA to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the IRA's MERP and EPA's GHGRP.

Commenter (2428-API) describes proposed adjustments in other section of this RTC, including initial comments on EPA's FEAST modeling. While the commenter is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal.

Response II-5-201: EPA acknowledges the commenter's input.

Comment: Commenter (2226-Thermo Fisher) applauds EPA's inclusion of a continuous emissions monitoring approach and the Agency's acknowledgment that technologies vary in how leaks are specifically detected. However, continuous emissions monitoring requires significant funding, and therefore raises uncertainty as to where such funding will come from, and in what

exact ways it will be allocated. It is possible that the oil and natural gas industry may not uptake continuous monitoring solutions in the near-term due to costs. The commenter encourages EPA to provide more insight into potential funding or support available to end-users to cover the cost delta between continuous monitoring and other solutions.

Response II-5-202: EPA recognizes the commenter's input.

Comment: Commenter (2315-NYSDEC) recommends that EPA reach out to researchers currently studying innovative detection technology. One study underway in New York State was presented at the American Geophysical Union (AGU) conference by Dr. Arvind Ravikumar, et al.<sup>100</sup> It should be noted that since this presentation, the scope of the study has already been expanded upon and more current work on continuous emissions monitoring is underway.

In addition to evaluating different technology and their associated challenges, Commenter (2315-NYSDEC) recommends that EPA also focus on the post-processing of the monitoring data because that may be a critical part of determining the reliability of the newest technology.

Response II-5-203: EPA acknowledges the commenter's input.

Comment: Commenter (2394-Earthworks) asserts that technology used together will increase emissions reductions and allow the EPA to gather information about new technologies with little impact on cost to operators.

Commenter (2394-Earthworks) notes as the EPA has said in the current proposed supplemental rule, while many new CEM systems exist, the "application of these systems appears to vary widely across the industry, with no consistent standard currently employed. This is especially true for how sources initiate identification of the cause of a leak." Therefore, there is a need to learn more about these systems and future systems before relying on them to reduce pollution.

Commenter (2394-Earthworks) states coupling new systems with a comprehensive LDAR program would allow the EPA to gather more information about the efficacy of new technologies. In the absence of sound evidence to show that any system or implementation methods can indeed identify and reduce pollution in the field, relying on these systems alone could just as likely miss pollution entirely and compromise the EPA's effort to improve air quality and limit impacts on public health.

Commenter (2394-Earthworks) notes an ongoing study from Colorado State University tested several CEMs in a blind study and found that at leak rates between .1 and 1 kg/hr "no solution reported mean estimates accurate to within  $\pm 40\%$ ." This is significant because this range "roughly corresponds to emission rates from component leaks that would be routinely identified in OGI surveys."<sup>101</sup> By using CEMs in a complementary role with the established industry

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<sup>100</sup> <https://agu2022fallmeeting-agu.ipostersessions.com/default.aspx?s=79-C0-1F-F4-21-F7-4E-81-AC-AD-5F-CD-B2-82-24-92&guestview=true>.

<sup>101</sup> ChemRxiv, "Performance of continuous emission monitoring solutions under single-blind controlled testing protocol." December 2022, <https://chemrxiv.org/engage/chemrxiv/article-details/638cd2ff14d92d3587a07c46>.



standard OGI cameras, the EPA would guarantee that current efforts to reduce emissions are not compromised.

Response II-5-204: EPA will evaluate the effectiveness of a technology as applied in the field as part of the alternative test method process as described in Section X.B.3 and XI.B.3 of the preamble of the rule. EPA is providing flexibility to the owner or operator to choose the best system that fits their needs.

Comment: Commenter (2394-Earthworks) states one unexpected consequence of Colorado's rollout of CEMs at well sites is an increased dismissal of verified complaints from NGOs and communities living near drilling activities. Over the last year an increasing number of the commenter's complaints have been dismissed simply because the operator claims that their CEMs on site show no sign of the pollution that was documented via OGI.

Commenter (2394-Earthworks) argues without proper rules in place to guide regulatory staff on how to compare conflicting sources of evidence, air pollution that may have previously been inspected further is now going unaddressed. This is not happening because CDPHE staff were directed to favor one technology over another. It is happening simply because new CEM technology was included in one rule.

Commenter (2394-Earthworks) highlights this to show that there are significant negative impacts that can happen by implementing new technology without extensive review of how it affects protocols throughout a regulatory framework. The current draft of the EPA's rules similarly does not provide protocol on how new technology will be compared. In order to protect public health and eliminate barriers to public participation the commenter encourages the EPA to provide protocol for how all acceptable alternative technologies should be compared.

Earthworks' field observations suggest that it is critical the EPA gather as much information as possible about how to best implement CEM systems. It also supports our recommendation to remove the option for operators to replace OGI LDAR with CEM systems at this time.

Commenter (2394-Earthworks) states ambient air monitoring is important to understand impacts to community health; however, only monitors that can reliably provide quantitative measurements are useful for indicating issues with point source pollution. There are technologies that may provide more accurate and quantitative measurements which the commenter thinks also need further investigation. One example is continuous fixed OGI cameras with automatic detection technology, such as those used in many refineries. These cameras are manufactured by FLIR, a highly accredited company which the EPA is familiar with, and others. However, your current draft rule suggests that the EPA is not likely to consider these. The commenter encourages the EPA to reconsider this decision. The EPA should explore the use of these, as well as satellite imagery and aircraft equipped with OGI cameras, all of which provide reliable, quantitative data which the EPA requires to make informed decisions about pollution events.

Response II-5-205: EPA recognizes the commenter's input.

Comment: Commenter (2412-University of Calgary Centre for Smart Emissions Sensing Technologies (CSEST)) provides a 14-page draft report on a relevant study undertaken to model the economics and efficacy of low-cost fixed sensors. The comments pertain most specifically to the following continuous monitoring systems solicitations:

- Equivalency with Other Fugitive Emissions Monitoring/Cover-CVS Requirement;
- Operational Downtime; and
- Site-Level Methane Emissions/Data.

According to commenter (2412-CSEST), the draft study unpacks how fugitive emissions management programs designed with the base of low-cost fixed sensors can be subject to large operational costs, primarily as a result of OGI survey callouts from automated alerts. The prevalence and complexity of emissions on upstream sites poses a severe issue for triaging these automated alarms and could put operators in a situation of facing an infeasible number of alarm follow-up calls. Although giving operators some latitude in their response to alarms would improve the economics of these low-cost fixed sensor programs – it is possible that this latitude would negatively affect emissions reductions goals.

The commenter's (2412-CSEST) study explores this issue, with discussion of the regulatory nuances and economic headwinds that may affect low-cost fixed sensor guided programs.

Commenter (2412-CSEST) believes the EPA should deeply consider the practicalities of low-cost fixed sensor-based fugitive emissions management programs – and think particularly carefully about how to manage follow-up from all sensors. Additionally, the commenter believes the EPA must carefully mandate some standards of practice for low-cost fixed sensors to ensure they are maintained with a quality management program that ensures a defined level of uptime and performance.

Response II-5-206: The alternative technology provisions in the rule are technology agnostic. EPA identifies that low-cost sensors will be used in some of the measurement systems which will petition for approval. Like for any other alternative technology, the request must include system specific QA/QC needed to ensure accurate operation and the manufacturer must define and data processing procedures used to derive an output. These criteria are explained in Section X.B.3 and XI.B.3 of the preamble of the rule.

#### ***5.9.16 Recommendations and Text Changes***

Comment: Commenter (2409-BP) recommends the following:

1. Amend the definition and framework for continuous monitoring to allow for continuous monitoring systems that may require action based on the concentration of emissions as well as those that may require action based on the rate of emissions, thereby making a distinction between the underlying technology and continuous monitoring systems that use algorithms to produce an emission rate estimate.
2. Allow continuous monitoring systems to qualify as periodic screening systems.

3. Modify the conditions that determine operational downtime and “out-of-control” monitors used in continuous monitoring systems.
4. Define the “root cause analysis” required for continuous monitoring systems to clarify that it is describing an investigation into the source of detected emissions.
5. Amend the information required in the fugitive emissions plan to reflect the potential for deployment of continuous monitors within the fenceline.
6. Remove the requirement that an alternative test method, such as a continuous monitoring system, must be “commercially available” to be approved for use under the rule; and
7. Clarify that the “daily verification checks” required for continuous monitoring systems include remote verifications.
8. EPA should expand the framework for continuous monitoring to allow for concentration-based action levels and detection thresholds.
9. EPA should make additional amendments to the continuous monitoring framework to more accurately reflect how such systems operate.

Response II-5-207: EPA acknowledges the comments, any revisions to the alternative technology provisions of the final rule are detailed in Section X.B and XI.B of the preamble of the rule.

Comment: Commenter (2333-LongPath) provides the following recommended changes to the continuous monitoring provisions alternative to OGI:

- Do not include greater response requirements or more stringent emissions thresholds for continuous technologies.
- Remove the Long-Term Action Level entirely for the continuous monitoring provisions, and maintain only the more effective Short-Term Action Level, based on the following findings:
  - The Long-Term Action Level does not achieve rapid find-and-fix, the primary goal of continuous monitoring.
  - Two thresholds that achieve the same emissions reductions is redundant. ○ No other screening approach requires double counting of emissions with two methods, which disincentivizes continuous monitoring.
  - The requirement for both a Long-Term and Short-Term Action Level adds a layer of operational complexity for operators, which disincentivizes continuous monitoring.
  - The 90-day Long-Term Action Level is more than an order of magnitude below the action levels proposed for periodic screening using other advanced technologies, despite a 60x increase in required frequency.
  - There is no equivalent standard to a Long-Term Action Level in either the OGI (BSER) or the periodic screening matrix, which disincentivizes continuous monitoring.
- Model all emissions reductions directly in FEAST, in particular to determine the Short-Term Action Level that results in equivalent emissions reductions (do not use FEAST results indirectly).
- Define Action Levels as “above Baseline Emissions” for the continuous monitoring provisions. This method has been vetted and approved by CDPHE and EPA under the

Colorado Alt. AIMM program. Without this change, continuous monitoring will be unusable for the majority of well sites and compressor stations.

- Define requirements for spatial (full site) coverage and/or the maximum timeframe in which potential plumes from all regulated equipment must be detected (all equipment must be screened).
- Define the Minimum Detection Limit requirements in a manner that is more consistent with the use and definition of minimum detection limits elsewhere in the rule.

Response II-5-208: EPA acknowledges the comments, any revisions to the alternative technology provisions of the final rule are detailed in Section X.B and XI.B of the preamble of the rule.

Comment: Commenter (2433-EDF *et al.*) supports EPA's proposed alternative fugitive monitoring standards and provide the following recommendations for improvements:

- *Require initial monitoring within 30 days.* The early stages of production often involve abnormal process emissions and operational issues that may cause significant fugitive emissions. To address this, Colorado requires operators to inspect a well “no later than 30 days after the facility commences operation.”<sup>102</sup> The commenter recommends that EPA similarly require that the initial monitoring survey occur earlier so these problems can be addressed sooner and mitigate potentially large emissions that would otherwise go undetected for up to 90 days.
- *Require targeted follow up on all detections.* Certain advanced screening technologies (*i.e.*, those with lower detection thresholds) may be capable of pinpointing the emitting equipment or component, allowing for direct repair and potentially obviating the need for a site wide OGI survey. For technologies that EPA determines are capable of pinpointing the emitting component, the commenter urges EPA to require immediate repair without a site wide OGI survey when results of periodic screening identify a specific component. For technologies that EPA determines are capable of pinpointing an emitting piece of equipment, the commenter urges EPA to require an OGI survey of that piece of equipment to locate the leaking component. If during follow up, an operator determines detected emissions are the result of normal operations and permissible, thus not requiring repair, that should be documented and reported to EPA. For technologies that detect at the site-level, or in cases where a specific component or piece of equipment cannot be determined based on the screening results, EPA should require a site-wide OGI survey to pinpoint the source. This survey should also satisfy the operator's annual OGI requirement if it covers all fugitive emissions components at the site. Again, emissions resulting from normal operations that do not require repair should also be documented and reported.
- *Align repair requirements.* EPA should require that all final repairs be completed within 30 days of detection or of receiving the results of a periodic screening. As described above regarding OGI, the commenter believes that a 30-day total repair timeline (including any follow-up survey, first attempt, and final repair) is feasible and necessary

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<sup>102</sup> 5 Colo. Code Regs. §1001-9-D-I.L.2. d. (2023).

to achieve the emissions reductions estimated by EPA. This timeline is feasible and already required by leading states.<sup>103</sup> In particular, results of aerial screenings are likely to indicate large emission events that should be quickly repaired. And to achieve the reductions anticipated by EPA through the equivalency modeling, regulatory repair timelines must align with modeling assumptions.

- *Align root cause analysis requirements.* The commenter supports EPA's proposed root cause analysis requirements for when emissions are detected from control devices, covers, and closed vent systems. These types of emission events may be large (particularly unlit or malfunctioning flares) and likely indicate a deviation from the applicable standards. A root cause analysis is an appropriate response and should be conducted as soon as possible to return the site back to normal and compliant operations. The commenter urges EPA to ensure these standards also apply when emissions from control devices, covers, and close vent systems are detected through OGI or AVO surveys under the primary standards.
- *Ensure monitoring plans are uniform.* The commenter supports providing flexibility to operators but urges EPA to ensure that applicable monitoring requirements are not so multifarious that it complicates compliance and enforcement efforts. The commenter therefore urges EPA to require that similar sites (based on either site characteristics or locations) be grouped together and subject to the same monitoring plan and screening option. The fugitive monitoring plan should also include the number and type of all pieces of major production and processing equipment at each site (including those relevant to the site's subcategorization), as well as the number of covers, closed vent systems, and control devices that are present at each site.
- *Align deployment and approval.* EPA should clearly specify in the regulatory text that periodic screening must occur 1) using a technology approved under the process described in section 60.5398b(d), 2) at the frequencies listed in Tables 1 and 2, and 3) in accordance with the standard and approved operating protocols. In other words, EPA should clarify in section 60.5398b(b) that the technology has to be deployed using the same operating protocols and under similar conditions as EPA approved under section 60.5398b(d). Technologies may be capable of achieving different requirements in Tables 1 and 2 under differing conditions or when following certain operational protocols. EPA must ensure deployment in the field conforms to the parameters approved by EPA.

Response II-5-209: EPA acknowledges the commenter's input and support for the rule. EPA has detailed the requirements with the advanced methane detection technology provisions in the rule as detailed in Section X.B of the preamble of the final rule and any revisions to these provisions are detailed in Section XI.B of the preamble of the final rule.

Comment: Commenters (2363-CEMC, 2402-DGCC) encourage the EPA to take into consideration continuous monitoring systems that have been approved for similar purposes under state regulatory programs, at a minimum to provide expedited approval of a technology. For example, CDPHE's Alt-AIMM program includes an extensive equivalency, and technology

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<sup>103</sup> See, e.g., Colo. Code Regs. § 1001-9-D-II.E.7; N.M. Code R. § 20.2.50.116(E) (2023).

feasibility review, to ensure approved continuous monitoring systems will meet the LDAR objectives, meeting or exceeding an already robust OGI camera LDAR inspection program.

Commenters (2363-CEMC, 2402-DGCC) encourage the EPA to not discount the significant efforts of technology providers and state regulators that demonstrate efficacy of continuous monitoring technologies, not only expediting approval, but also adoption of approved systems resulting in greater emissions reduction more quickly.

Commenter (2402-DGCC) states the EPA's approach could be particularly important and valuable because by the time states are developing and submitting their EG OOOOc plans, the agency will hopefully have approved several methods. This will make it possible for state plans to authorize or require the use of technologies that provide improved detection and more precise quantification.

Response II-5-210: EPA has retained the authority to approve alternative technology for use in NSPS OOOOb and EG OOOOc. We recognize that some states have existing programs as part of a SIP, while information gathered as part of those programs could be useful for evaluating technology, however EPA will not offer expedited approval and they will be evaluated as detailed in Section X.B.3 and XI.B.3.

Comment: Commenters (2363-CEMC, 2448-Project Canary) requests additional clarity regarding the third-party provider requirement in §60.5398b(c)(2)(iii) which states:

“If the continuous monitoring system is administered through a third-party provider, contact information where the provider can be reached 24-hours a day.”

In many cases, an operator has a lease agreement with a technology provider to install and maintain a continuous monitoring system. However, these agreements also make clear that the operator has the day-to-day responsibility to take any corrective actions. Accordingly, the commenter suggests the EPA provide additional clarity to the phrase “administered by a third-party” to make clear that any entity providing only installation and maintenance services is not liable for any requirements under the NSPS OOOOb or EG OOOOc regulations.

Response II-5-211: The provision above is from the requirements for an owner or operator to develop a monitoring plan, it is the owner or operator's choice to third-party provider to support compliance activities, however only the owner or operator is responsible for compliance with applicable emission standards.

Comment: Commenters (2363-CEMC, 2448-Project Canary) are also asking for EPA to clarify the intent of providing contact information for an individual to be reached 24-hours a day. As the continuous emissions monitoring program is proposed with rolling 7-day and 90-day averages, the commenters are requesting that the EPA provide additional information regarding the intent or need for a 24-hour-a-day contact. The fugitive monitoring plan submitted to the EPA will make clear how the operator is notified (email, text, or other) when an action level is exceeded, and corrective action is required.

Response II-5-212: For the continuous monitoring work practice to be equivalent to the fugitive emissions BSER, the continuous monitoring system must be able to provide data on an ongoing basis. Therefore, EPA included a maximum system downtime in the rulemaking. It is critical that owners and operators be able to contact third-party providers any time that the system goes down, otherwise they face the risk of being out-of-compliance with the downtime requirement.

Comment: Commenters (2363-CEMC, 2448-Project Canary) seek clarity about the replacement of OGI/Method 21 and AVO if an operator adopts an approved continuous monitoring system in §60.5398b(c).

The Preamble to the Supplemental Proposal states:

Lastly, we are proposing to establish a clear and streamlined pathway for technology developers and other entities to seek the EPA's approval for the use of advanced measurement technologies under this alternative screening option. Under this pathway, entities would seek approval for alternative test methods to demonstrate the performance of alternative technologies, which would replace the use of OGI and AVO for fugitive emissions monitoring and the use of OGI for no identifiable emissions monitoring of covers and CVS (see section IV.K of this preamble) in both the proposed NSPS OOOOb and EG OOOOc.

Commenters (2363-CEMC, 2448-Project Canary) respectfully request that the agency explicitly incorporate this approach into the NSPS OOOOb, EG OOOOc regulatory language. Below is suggested regulatory text for §60.5398b (underlined text represents recommended addition):

**What alternative GHG and VOC standards apply to fugitive emissions components affected facilities and covers and closed vent systems?**

This section provides alternative GHG and VOC standards for fugitive emissions components affected facilities in §60.5397b and alternative initial and continuous compliance requirements for covers and closed vent systems in §60.5416b. As provided in this section, owners and operators of affected facilities may choose to demonstrate compliance with these alternative standards in lieu of complying with the standards that would otherwise apply under §60.5397b and §60.5416b. If you choose to demonstrate compliance with the alternative GHG and VOC standards through periodic screening, you are subject to the requirements in paragraph (b) of this section. If you choose to demonstrate compliance through a continuous monitoring system, you are subject to the requirements in paragraph (c) of this section. The technology used for periodic screenings under paragraph (b) of this section or continuous monitoring under paragraph (c) of this section must be approved in accordance with paragraph (d) of this section.

Response II-5-213: EPA recognizes the commenters suggested language revisions to the final rule. EPA has made slight revisions to the regulatory text in §60.5398b to clarify what standards are covered by the alternative GHG and VOC standards for fugitive emissions components affected facilities and covers and closed vent systems. The opening of §60.5398b now states:

This section provides alternative GHG and VOC standards for fugitive emissions components affected facilities in §60.5397b and alternative continuous inspection and monitoring requirements for covers and closed vent systems in §60.5416b(a)(1)(ii) and (iii), (2)(ii) through (iv), and (3)(iii) and (iv).

Comment: Commenters (2363-CEMC, 2448-Project Canary) seek clarification about the timeframe rules that apply when an operator switches to using a continuous monitoring system from using another approved monitoring technology. Proposed §60.5398b(c)(3)(v) provides that operator must install and begin conducting monitoring with a continuous monitoring system.

Commenters (2363-CEMC, 2448-Project Canary) understand that this rule requires an operator switching from use of OGI cameras to a continuous monitoring system to begin operation of the continuous monitoring system no later than the date that the next OGI survey would have been required—whether for fugitive emissions components (§60.5397b) or for covers and closed vent systems (§60.5416b). The commenter would appreciate it if the agency could confirm this interpretation in the final rule.

Commenters (2363-CEMC, 2448-Project Canary) say that also, this provision does not address a scenario in which an operator switches from using an approved alternative periodic surveying method to using a continuous monitoring system. Accordingly, the commenters recommend the following revision:

No later than the final date by which the next monitoring survey required by §60.5397b(g)(1)(i) through (iv) would have been required to be conducted if you were previously complying with the requirements in §60.5397b and §60.5416b or §60.5398b.

Response II-5-214: EPA did not contemplate companies switching from a periodic screening alternative to a continuous monitoring alternative in the proposed rule, however we find the suggested revision to be overly restrictive since it could require a continuous system to be on-line within 30 days from the most recent periodic screening.

Therefore, for those owner or operators choosing to switch from the periodic screening alternative to a continuous monitoring alternative, you have within 120 days from your last screening event to conduct the site-specific baseline assessment and to initiate monitoring with your continuous monitoring system.

Comment: Commenters (2363-CEMC, 2448-Project Canary) are providing comment on the phrase “at least once every twelve-hour block.” While the commenters are supportive of the frequency for determining a valid mass emissions rate, they believe the proposal is ambiguous regarding allowable timeframes between reporting a valid emissions rate once every twelve-hour block. For example, some measurement systems are able to calculate mass emissions rate on a much more frequent basis. In such scenarios, two valid mass emissions rates could be calculated just minutes apart, meeting the proposed language as written. To provide compliance certainty, the commenter requests that EPA further clarify this language and specify if a minimum period of time is required between calculations of valid mass emissions rates during a twelve-hour block.



Commenter (2448-Project Canary) supports EPA’s proposal in §60.5398b(c)(1) to define continuous monitoring as the ability of a system to determine and record a valid mass emissions rate at least once every twelve-hour block. However, the commenter believes the term “valid mass emissions rate” should be defined more clearly as the language is vague and could be subject to varying interpretations. The commenter proposes the following:

“Valid Mass Emissions Rate” means any methane rate determined by the measurement system using system data within the prescribed operating ranges provided in the monitoring system approval. Data used to calculate a methane emissions rate that is outside the prescribed parameters shall invalidate that emissions rate.

Response II-5-215: EPA acknowledges the commenters’ support for the rule and the feedback. The 12-hour block is a minimum time frequency and if a system can measure a more frequent time block, they are allowed so long as that time resolution is maintained. How the block averages are determined for a system must be detailed as part of the advanced methane detection technology alternative test method process.

Comment: Commenters (2363-CEMC, 2448-Project Canary) provide two recommendations for revisions to regulatory text in §60.5398b(c). First, the reference to subparagraph (c)(1)(ii)(A) should reference subparagraph (c)(1)(iii)(A). Second, in the commenters’ view, the requirement in this section to “continuously collect the data” could result in confusion. The commenter’s concern is that the term “continuously collect” could be read colloquially, implying a perpetual requirement to collect data. However, paragraph (c)(1) —to which this text references— expressly defines “continuous monitoring” to establish a requirement for coverage in 12-hour blocks.

For these reasons, commenters (2363-CEMC, 2448-Project Canary) recommend revising §60.5398b(c)(1)(iii) as follows:

“(iii) The continuous monitoring system must ~~continuously~~ collect data as specified in paragraph (c)(1) of this section, except as specified in paragraphs (c)(1)(iii)(A) through (D) of this section.”

Response II-5-216: EPA recognizes the input and has chosen to finalize the provision as proposed. EPA has defined continuously as meaning the ability of a methane monitoring system to determine and record a valid methane mass emissions rate or equivalent of affected facilities at least once for every 12-hour block.

Comment: Commenters (2363-CEMC, 2448-Project Canary) support the inclusion of health checks for devices within the continuous monitoring system in §60.5398b(c)(1); however, believes that, as written, the requirement is overly prescriptive and unnecessary. This provision requires that continuous monitoring systems “must be confirmed for power and connectivity at least twice every six-hour block.” Such an “always-on” requirement may make sense for facilities subject to Compliance Assurance Monitoring (CAM) [40 CFR Parts 64, 70 and 71] or other continuous monitoring system requirements under non-methane-related regulations.

Commenters (2363-CEMC, 2448-Project Canary) indicate that sources subject to such requirements are of significant size and technical complexity so as to justify well-connected data transfer services, such as satellite or SCADA systems. As such, reliable connectivity and the ability to upload or send data is necessary due to the complexity of the facilities subject to these requirements. This includes large natural gas compressor stations, gas processing plants, refineries, and power plants.

Commenters (2363-CEMC, 2448-Project Canary) add, by contrast, production facilities and gathering and boosting facilities are significantly smaller in size, lower in complexity, more numerous and often constructed in areas with less reliable access to communication systems, often limited to commercial cellular networks. In some instances, especially in rural or remote locations, cellular service can be interrupted for periods of time, limiting the ability to upload data to a cloud-based system as frequently as is possible in areas with strong cellular coverage. If EPA imposes an “always-on” requirement for continuous monitors, it could disincentivize the use of such systems in some rural or remote areas that have substantial oil and gas production.

Moreover, commenters (2363-CEMC, 2448-Project Canary) say such an “always-on” requirement is not necessary to ensure environmental performance. An interruption in cellular service does not necessarily render a continuous monitoring system ineffective. During these situations, the continuous monitoring system is still operating, storing the data within the monitoring system until such time as the cellular connection is re-established. Once reconnection occurs, all data that wasn’t successfully uploaded will be “backfilled” to minimize, or eliminate, any data gaps.

While commenters (2363-CEMC, 2448-Project Canary) understand the importance of timely data to compare against action levels, they encourage the EPA to allow up to 24 hours of data to be backfilled. As amended, the provision would read as follows:

(ii) The health of the devices used within the continuous monitoring system must be confirmed for power and connectivity at least twice every six-hour block, provided that, if a device has the capability to backfill data during a connectivity disruption, the confirmation requirement for connectivity shall be once every 24-hour block.”

As shown in the table below, the percentage of data to be backfilled under such a rule would be less than 15 percent for the short-term action level and just over 1 percent for the long-term action level. Commenters (2363-CEMC, 2448-Project Canary) believe this process allows for connectivity issues outside of an operator’s control, while still providing adequate data to determine if an action level has been triggered within a reasonable period of time.

[Table shows for 12 hours backfilled, the Percent of Backfilled Data per Action Level Duration for a 7-day rolling average would be 7.1% and for a 90-day rolling average would be 0.6%, for 18 hours backfilled, the Percent of Backfilled Data per Action Level Duration for a 7-day rolling average would be 10.7% and for a 90-day rolling average would be 0.8%, and for 24 hours backfilled, the Percent of Backfilled Data per Action Level Duration for a 7-day rolling average would be 14.3% and for a 90-day rolling average would be 1.1%.]

Commenters (2363-CEMC, 2448-Project Canary) states accommodating this operational reality will still provide the operator and EPA with the information needed to take timely corrective action, even after a temporary interruption in service. In any event, to the extent that periodic surveying with OGI and Method 21 is the “best system of emission reduction” that has been “adequately demonstrated”, continuous monitoring will provide higher quality data than OGI and Method 21 even with interruptions in cellular service from time to time. As noted in a recent study; “While fixed duration emission events may not be detected and there can be time delays in detecting continuous infinite duration emissions events, the detection efficiencies for CM networks are greater than efficiencies for periodic short duration measurements such as monthly or quarterly inspections”.<sup>104</sup>

Response II-5-217: EPA acknowledges the commenters’ suggestions and have made some revisions to the alternative continuous monitoring approach as detailed in Section X.B.2 and XI.B.2 of the preamble of the final rule.

Comment: Commenter (2448-Project Canary) strongly supports the EPA’s inclusion of provisions in the Supplemental Proposal allowing operators to use advanced methane detection technologies for compliance purposes. However, the EPA has proposed to find that—at least at this time—periodic surveying with OGI and Method 21 is the “best system of emission reduction” that has been “adequately demonstrated.” There is substantial evidence that OGI and Method 21 systems fail to detect significant volumes of intermittent leaks that occur in between surveys, including leaks that qualify as “super-emitter” events. Additionally, as a recent study focusing on detection limits for OGI cameras indicates, “[o]verall detection rates from the camera-surveyor system are substantially lower than the detection rates estimated from studies focused solely on the camera performance...”<sup>105</sup> Further, the OGI surveyor experience level can also have a large impact on OGI use efficacy: “Study results indicate that OGI survey experience significantly impacts leak detection rate: Surveyors from operators/contractors who had surveyed more than 551 sites prior to testing detected 1.7 (1.5– 1.8) times more leaks than surveyors who had completed fewer surveys.”<sup>106</sup>

To the extent that it promotes greater deployment of continuous monitoring systems, the Final Rule will also advance several additional public policy objectives:

1. Making it possible, and incentivizing operators, to use alternative test methods is critical to the Agency’s ultimate goals for this rulemaking and for the impending rules for the Methane Emissions Reduction Program (MERP) and Subpart W established in §60113 of the Inflation Reduction Act. The MERP relies on methane intensity, which is why Congress also mandated in §60113 that the EPA update Subpart W to require “accurate” and “empirical” data. Advanced technologies, such as continuous monitoring solutions,

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<sup>104</sup> Assessing detection efficiencies for continuous methane emissions monitoring systems at oil and gas production sites, Qining Chen, Colette Schissel, Yosuke Kimura, Gary McGaughey, Elena McDonald-Buller, and David T. Allen, *Environ. Sci. Technol.* 2023, 57, 4, 1788–1796. <https://pubs.acs.org/doi/abs/10.1021/acs.est.2c06990>.

<sup>105</sup> Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Environ. Sci. Technol.* 2020, 54, 18, 11506–11514, Publication Date: August 7, 2020. <https://pubs.acs.org/doi/full/10.1021/acs.est.0c01285>.

<sup>106</sup> *Id.*

provide the greatest temporal resolution, resulting in the most representative emissions profile and methane intensity of an oil and gas facility. Compliance with these new requirements is simply not achievable without advanced technologies and continuous monitoring. A February 2023 study summarizes this well:

“This work presents a real-world demonstration of how [continuous monitoring systems (CMS)] can be used to reconcile top-down measurements and bottom up inventories at the site-level. The Inflation Reduction Act requires accurate emissions estimates at this scale, and voluntary methane mitigation initiatives such as OGMP 2.0 require source- and site-level reconciliation of measurements with inventory estimates. While accurate basin-level emission estimates can be obtained through aerial surveys with large sample sizes, site-level estimates for individual operators require detailed temporal characterization of intermittent emission events. Information on such emission events, obtained through CMS in this work, will be critical for effectively creating site-specific measurement-informed inventories.<sup>107</sup>”

2. Expanded monitoring infrastructure will generate additional reductions of methane emissions and additional reductions of emissions of ozone-causing volatile organic compounds (VOCs). Both the methane and VOC reductions will have substantial health and welfare benefits for affected communities, thereby addressing important environmental justice goals.
3. Increasing deployment of continuous monitoring systems will help the EPA develop a more accurate methane emissions inventory for the entire oil and gas sector. In most cases, continuous monitoring systems provide the most complete picture of emissions and offer the greatest opportunity to achieve the nation’s methane reduction goals by 2030. Because continuous monitoring systems more accurately and frequently detect leaks, increased deployment of such systems will also allow resources for mitigation to be more effectively deployed, thereby increasing the emission reduction impact per dollar spent.
4. Increased deployment of advanced monitoring technologies across a variety of well sites will help develop valuable information for the EPA about the performance of different configurations of these technologies in different settings, which will provide EPA with information to develop specific guidance on the proper operation of these systems. Greater deployment is consistent with the EPA’s mandate to promote technological innovation.
5. EPA investment in continuous monitoring system infrastructure will ensure short-, medium and especially long-term effective emission measurement and reductions. As super-emitter events are reduced in the future with improved satellite and aerial technologies, unintentional basin emissions will be increasingly dominated by smaller sources, which are more effectively discovered through continuous monitoring systems.

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<sup>107</sup> Daniels W, Wang J (L, Ravikumar A, Harrison M, Roman-White S, George F, et al. Towards multi-scale measurement-informed methane inventories: reconciling bottom-up inventories with top-down measurements using continuous monitoring systems. ChemRxiv. Cambridge: Cambridge Open Engage; 2023. This content is a preprint and has not been peer-reviewed <https://chemrxiv.org/engage/chemrxiv/article/details/63e526b9fcfb27a31f7c0a6c>.

Response II-5-218: EPA recognizes the commenter's support for the alternative continuous monitoring approach.

Comment: Commenter (2196-Private Citizen) references the following possible typos or reference errors:

- 60.5398b(c)(1)(i) The sensitivity of the system must be such that it can at least measure an order of magnitude less than the action-level defined in paragraph **(c)(4)(iii)** of this section.

Commenter (2196-Private Citizen) states there is no paragraph (C)(4)(iii), possibly meant (C)(4)(i) & (ii).

- 60.5398b(c)(1)(iii) The continuous monitoring system must continuously collect data as specified in paragraph (c)(1) of this section, except as specified in paragraphs **(c)(1)(ii)(A) through (D)** of this section.

Commenter (2196-Private Citizen) argues there is no paragraph (C)(1)(ii)(A) through (D), possibly meant (C)(1)(iii)(A) through (D).

Response II-5-219: EPA recognizes the commenter's input and EPA has made revisions to the final rule.

## **5.10 Alternative Test Method Approval**

### ***5.10.1 General Comments/Support***

Comment: Commenter (2355-CEC) respectfully recommends that EPA carefully assess proposed alternative test methods. Different types of advanced monitoring technologies may perform better or worse in different configurations, at different types of sites, and in different types of weather conditions. For these reasons, the commenter urges the Agency to make full use of its authorities to condition the approval of alternative test methods on specific work practices for use of those methods.

Response II-5-220: EPA recognizes the commenter's recommendations. The submissions requirements for alternative test methods are detailed in the final rule. EPA will be thoroughly reviewing all submitted materials to determine whether the alternative test method is appropriate for the specified application. This includes evaluation of technology limitations due to weather, site types, configurations, etc.

Comment: Commenter (2288-North Dakota Department of Environmental Quality) supports EPA's encouragement of new compliance methods provided EPA's review process is prompt and acknowledges the impact local climate conditions (North Dakota winters) may have on their accuracy and reliability.

Response II-5-221: EPA acknowledges the commenter's input. The submissions requirements for alternative test methods are detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA will be thoroughly reviewing all submitted materials to determine whether the alternative test method is appropriate for the specified application and an evaluation of any potential limitations, such as weather conditions.

Comment: Commenter (DRAFT-154255-Colorado Air Pollution Control Division (CAPCD)) notes that Colorado has made significant progress in evaluating alternative monitoring methods for hydrocarbons and continues to participate in the ongoing development of equivalency frameworks to encourage effective deployment of alternative monitoring methods to detect both GHG and hydrocarbons.<sup>108</sup>

Response II-5-222: Thank you for your comments. EPA appreciates your efforts.

Comment: Commenter (1686/2345-GHGSat) agrees with EPA's proposal to require alternative technology to be catalogued as a Performance Test method as dictated by 40 CFR 60.8(b)(3). EPA should spearhead the vetting and qualification process due to the current diversity of alternative technologies and the lack of standardized methods and performance specifications. The commenter believes that the EPA should be the main approver of technology and use the Performance Test method stipulated in 40 CFR 60.8(b)(3), with the idea of eventually delegating authority to the States. For companies operating under the Federal Title V permit, this determination simplifies the permitting process and sets the basis for incorporating procedures for compliance. For entities not required to obtain a Federal Operating permit, the States should be able to authorize the use and implementation of alternative technologies, since the EPA will eventually grant delegating authority to the States.

Response II-5-223: EPA appreciates the support for the rule and the comments received. The submissions requirements for alternative test methods detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA will be the main approver of technology and will be thoroughly reviewing all submitted materials to determine whether the alternative test method is appropriate for the specified application.

### ***5.10.2 Overall Recommendations and Clarifications to Streamline Approval***

Comment: Commenter (2316-ABB) urges EPA to consider establishing a rigorous and achievable minimum detection and quantification threshold and to highlight the importance of other performance parameters such as time response, linearity, overall accuracy (e.g., cross sensitivity, rates of false positives and false negatives), operational lifetime, and maintenance/calibration requirements. All requirements should be able to be met by commercially available technology.

Response II-5-224: EPA recognizes the commenter's recommendations. The submissions requirements for alternative test methods are detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA will be thoroughly reviewing all submitted materials, including

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<sup>108</sup> See Colorado's Approved Instrument Monitoring Method (AIMM) for oil & gas, <https://cdphe.colorado.gov/oil-and-gas-and-your-health/approved-instrument-monitoring-method-aimm-for-oil-gas>.

performance parameters, to determine whether the alternative test method is appropriate for the specified application.

Comment: Commenter (2433-EDF *et al.*) states prior to regulatory deployment, screening technologies and continuous monitoring technologies must be approved by EPA through a process that “will include consideration of the combination of the measurement technology and the standard protocol for its operation.” Both aspects are critical because the detection capability of a given technology can vary greatly depending on operating protocols and conditions. The alternative test method approval process must therefore assess technology performance under a wide variety of conditions representative of field conditions in diverse basins across the country. A technology should then be approved as meeting a specified detection threshold that it is capable of routinely and reliably achieving under a variety of conditions. The commenter supports EPA’s proposed approval process and provides the following general recommendations (more details can be found in the commenter’s letter):

- Eliminate conditional approval.
- Address basin- and site-specific requests through the AMEL process.
- Enable public participation.
- Define follow-up and repair requirements.

Response II-5-225: The EPA thanks you for your support and appreciates your recommendations. The final rule includes follow-up and repair requirements based on the spatial resolution of the technology as detailed in Section X.B.1 and XI.B.1 of the preamble of the final rule. Additionally, the final rule includes detailed submission requirements that will allow EPA to review the alternative test method technology and operational protocols.

Comment: Commenter (2326-AXPC) believes that EPA should not only rely on the ability to determine a mass emission rate when assessing alternative leak detection technologies due to the large discrepancies that can occur with mass conversion. EPA should also allow alternative leak detection technologies to use a background concentration and increase from that background level as a means to provide an action level for leak detection. The conversion of a detected concentration of methane to a mass emission rate is an added step in estimation that requires site-specific operational data/information that only the operator can provide. Testing of third-party data indicates that there can be a large discrepancy in the mass conversion. Alternative leak detection technologies can also identify a background concentration of molecules and base its action levels on an increase from that background level. This method of detection can be a reliable method of detecting and responding to leaks in real time and does not have some of the challenges presented by mass conversion based off of operator data and calculations.

Response II-5-226: Thank you for your comments. The final rule includes procedures for establishing site-specific baseline emission for the continuous monitoring systems and the action levels are based on mass emissions of methane over the site-specific baseline.

Comment: Commenter (2203-Ceres) notes that EPA should ensure that any testing is rigorous under a variety of conditions and supported by peer-reviewed and independent research.

Response II-5-227: Thank you for your recommendations. The submissions requirements for alternative test methods are detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. The following language has been added:

*“Published reports (e.g., scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The published reports must identify either a site-level or aggregate detection threshold and be accompanied with sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures. The supporting data may be included in the published report or may be submitted separately.”*

Published reports should include peer-reviews journal articles and double- or triple-blind studies. As the commenter notes, testing of the alternative methane technology must be done under a variety of relevant environmental conditions.

Comment: Commenter (2213-Oxy) supports EPA’s proposal to streamline the use of these technologies through a pre-approved alternative screening approach in lieu of the proposed nine-month application process. The commenter supports the requirement to survey wellhead-only sites but the feasibility of surveying all of these locations requires the use of alternative technologies to satisfy the requirements. These alternative technologies need a streamlined approval process to allow for early adoption once the rule is finalized. Accordingly, the commenter encourages EPA to work with all stakeholders to further develop the proposed advanced measurement technology framework prior to issuing the final rules.

Response II-5-228: EPA thanks you for your support and comments. In the final rule, EPA has provided a framework for submission that is design to ensure all materials required by EPA are submitted so EPA can thoroughly review all materials.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) recommend that the EPA make a limited modification to section 60.5398b(d)(1)(iv), which provides that the agency may require an operator using an approved alternative test method to demonstrate compliance with an OGI camera if the agency “finds reasonable grounds to dispute the results obtained” by the alternative test method.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) note that this provision appears to assume that an operator that has opted to use an approved alternative test method will continue to have OGI cameras on-site and available. That might be the case if the alternative test method is a periodic surveying technology—because the Supplemental Proposal requires that use of such technologies is coupled with periodic OGI surveys. However, there is not a similar requirement for use of approved continuous monitoring systems.

For this reason, commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) recommend that the EPA integrate a “grace period” between the agency’s notification of dispute and the operator’s OGI camera survey. Such a period will make it possible for the operator to procure



OGI camera surveying services if it does not already have such services. The commenters recommended the following edits:

“(iv) If the Administrator finds reasonable grounds to dispute the results obtained by any alternative test method for the purposes of demonstrating compliance with a relevant standard, the Administrator may require you to demonstrate compliance according to §60.5397b for fugitive emissions components, affected facilities and §60.5416b for covers and closed vent systems within 30 days of the Administrator’s notification to you of disputed results.”

Response II-5-229: EPA disagrees with the commenters that a grace period is needed for this requirement. EPA has not stipulated that monitoring according to §60.5397b and §60.5416b must be performed if the Administrator finds reasonable grounds to dispute the results obtained by the alternative test method, only that it may be required. This decision will be made on a site-specific basis considering whether the dispute can be remedied in another manner, whether a different technology was deployed in the case of a periodic screening event, and the source of the dispute in the results. If the Administrator determines that the owner or operator must perform monitoring according to §60.5397b and §60.5416b, the Administrator is best suited to making that decision at the time of the dispute, considering factors such as the reason for the dispute, type of site and regulated components, and previous inspection results.

Comment: Commenter (2284-Kairos) echo the comments of the Methane Roundtable and others, who suggest that EPA focus its initial review and approval efforts on alternative technologies that have already been established as commercially and operationally viable so that the most promising technologies can be deployed as quickly as possible.

*Recommendation:* Prioritize technologies with high commercial readiness and potential for rapid deployment for approval and establish a streamlined review process for minor changes to approved technologies.

Response II-5-230: EPA thanks you for your recommendations. EPA has established rigorous submission requirements for readily available technologies as detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. No specific technology will be prioritized. Technologies will be reviewed as they are received. The review timeline is included in the final rule.

Comment: Commenter (2192-BSM) indicates that daily verifications are impractical and unnecessary for many screening technologies. Procedures for verifying measurement sensitivity, calibration intervals, etc. should be allowed to vary by technology. The commenter would recommend that technology specific operating procedures be included in the technology approval process.

Response II-5-231: Thank you for your comments and recommendations. The final rule includes requirements to submit standard operating procedures as well as alternative testing procedures for the technology. Both of these documents will be reviewed by EPA as part of our evaluation process.

Comment: In response to EPA's request for comment,<sup>109</sup> commenter (2298-Pioneer) echoes the Harvard Methane Roundtable comments and recommends EPA clarify information that companies must include in alternative test method applications. This is necessary to support EPA's ability to efficiently review and approve complete applications that demonstrate equivalent or better methane detection and reductions. In developing the final rule and any associated guidance, EPA should consider best practices and information required from methane detection approval processes in other jurisdictions.

Commenter (2298-Pioneer) provides the following example:

- EPA should clarify what information requestors should submit for EPA to approve the “operating window” and technology settings in which the specific test method will meet the matrix requirements.<sup>110</sup> The operating window within the work practice standards should prescribe the necessary environmental conditions in which operators may monitor with the specific test method including conditions related to weather, topography, daylight, windspeed, temperature, humidity, sunlight, and ground cover.
- EPA should require that companies submit at least two studies to demonstrate equivalency: (1) applied in the field and (2) under controlled conditions.<sup>111</sup> In guidance, EPA can specify certain testing facilities to conduct controlled testing.<sup>112</sup>
- EPA should require companies to submit information on the test method's ability to localize a leak detection and any other information to help EPA require appropriate response requirements to replace a full site wide OGI sweep.

Response II-5-232: Thank you for your recommendations. The submissions requirements for alternative test methods have been expanded and revised as detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule in the final rule. EPA will be thoroughly reviewing all submitted materials to determine whether the alternative test method is appropriate for the specified application. This includes evaluation of technology limitations due to weather, site types, configurations, etc. The final rule also outlines requirements for submitting published reports evaluating the technology, supporting information and data verifying the technology meets the aggregate detection threshold(s), as well as supporting information verifying spatial resolution of the technology.

Comment: Commenters (2298-Pioneer, 2342-Harvard's Environmental and Energy Law Program (EELP)) also expect that as EPA undertakes review of any application, EPA may ask the company for additional information or clarifications. The commenters recommend EPA make clear that such a request during the review process will not restart the 270-day period or require an applicant to submit a new application. This clarification is consistent with EPA's practice. While the commenters support the proposed conditional approval process to avoid backlogging

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<sup>109</sup> "The EPA solicits comment on the proposed information required to be submitted with the application of an alternative test method and whether the EPA should consider requiring any additional information." 87 Fed. Reg. 74702, 74746 (Dec. 6, 2022).

<sup>110</sup> See Colorado Approved Instrument Monitoring Methods (AIMM) Guidance & Procedures, p. 2.

<sup>111</sup> See AIMM Guidance & Procedures, p. 6; see also AL T-150 Approval Letter, pp. 4-8.

<sup>112</sup> See AIMM Guidance & Procedures, p. 6, suggesting the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University may be used to conduct field testing.

effective advanced technologies, they encourage EPA to include a process for stakeholders to have notice of conditionally approved technologies and offer comments on their effectiveness and use.<sup>113</sup> For example, EPA could publish the application on its website with a statement that the test method will be conditionally approved by a certain date unless EPA receives substantive adverse comments.

Response II-5-233: EPA thanks you for your comments. The 270-day period will not restart if more information or supporting data is requested by EPA. The requestor will have the option to pull back their submission and resubmit at a later date if, for example, the requested information will require more than 270 days to hand over to the EPA. EPA will make all decisions related to approval and disapproval of alternative test methods based on the information that is provided in the submitted materials. If the submitted materials are incomplete or inadequate, the submission may be denied.

Comment: Commenters (2298-Pioneer, 2342-EELP) also recommend that once an application is approved, EPA provide a separate and expedited process to approve minor changes (*e.g.*, technology updates, etc.) to an approved technology without requiring a new application to submit a new alternative test method application. However, commenter (2342-EELP) also urges EPA to clarify that minor updates (*e.g.*, software updates) to an already approved technology that do not affect technology performance should not require EPA approvals.

Response II-5-234: EPA agrees with the commenter that minor updates to software that are intended to improve the Quality of Life (QoL) to improve workflow should not be subject to reapproval, however EPA does believe that changes to programming which would result in a substantive change in the output of a system must be subject to some level of re-approval. EPA has made revisions in the final rule to define when changes in software would trigger re-approval and to provide an expedited process for existing technology that has been previously approved.

Comment: In response to EPA's request for comment,<sup>114</sup> commenters (2342-EELP, 2363-CEMC, 2448-Project Canary) recommend EPA clarify information that companies requesting approval ("requestors") must include in alternative test method applications. This is necessary to support EPA's ability to efficiently review and approve complete applications that demonstrate equivalent or better methane detection and reductions. In developing the Final Rule and any associated guidance, EPA should consider best practices and information required from methane

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<sup>113</sup> This recommendation is in response to EPA's request for comment: "The EPA is proposing a defined timeframe for review and determination of alternative test method requests by the Agency. The EPA is proposing to issue either an approval or disapproval in writing to the requestor within 270 days of receipt of the request, with a number of milestones for acknowledgement of receipt and initial reviews. [ ...] The EPA solicits comments on the proposed timeframe to review and approve alternative test methods and whether alternative timelines should be considered." 87 Fed. Reg. 74746.

<sup>114</sup> "The EPA solicits comment on the proposed information required to be submitted with the application of an alternative test method and whether the EPA should consider requiring any additional information." 87 Fed. Reg. 74702, 74746 (Dec. 6, 2022).

detection approval processes in other jurisdictions, including the Colorado Alternative Approved Instrument Monitoring Methods (AIMM) process.<sup>115</sup>

Response II-5-235: EPA has revised the rule as detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule to clarify the required information that must be submitted when seeking approval.

Comment: Commenter (2227-Western Energy Alliance (WEA)) recommends that EPA establish a set of pre-approved alternative methane detection technologies. Also, the commenter recommends that validation of advanced methane detection technologies should be outside of the NSPS and EG.

Response II-5-236: EPA thanks you for your recommendations. EPA has established rigorous submission requirements for readily available technologies in the final rule. All technologies will undergo the same review process by EPA as the submissions are received.

Comment: Commenter (2193-California Air Resources Board (CARB)) urges EPA to include all approved advanced technology alternatives in the Emissions Measurement Center (EMC) website, not just the broadly applicable ones, to better streamline the 111(d) Plan implementation process.

Commenter (2193-CARB) states the Supplemental Rule includes that well sites and compressor stations may utilize alternative monitoring systems, optional advanced screening may be utilized, and that M21 inspections may be utilized in lieu of OGI monitoring for fugitive emissions.<sup>116</sup> Instead of indicating whether EPA intends to provide a list designating which alternative monitoring systems may be permissible, the Supplemental Rule states that "[w]hile there was widespread support of the concept of an alternative screening option, the EPA still does not have enough information to conduct the requisite BSER analysis for any specific advanced measurement technology to determine whether it would qualify as the BSER for detecting fugitive emissions."<sup>117</sup> Because this technology is not presently known, EPA has proposed sensitivity parameters based upon testing frequency for the level of emissions any proposed advanced technology would need to detect and discusses how best to utilize continuous monitoring systems.<sup>118</sup> However, with respect to the approval process, it only states that it wants to establish a system to streamline the approval of the alternative systems.<sup>119</sup> "Once an alternative test method or alternative technology has been approved, if it is broadly applicable, EPA will post it to the Emissions Measurement Center website" so other owner/operators who meet the requirements may utilize the technology as well, but "broadly applicable" is never

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<sup>115</sup> See AIMM Guidance & Procedures, <https://oitco.hylandcloud.com/Pop/docpop/docpop.aspx>, and pending applications, <https://cdphe.colorado.gov/public-information/alternative-aimm-public-notices>; the Alberta Energy Regulator (AER) Alternative Fugitive Emissions Management Program (Alt-FEMP) and New Mexico Advanced Leak and Repair Monitoring (ALARM) program in New Mexico are other examples.

<sup>116</sup> 87 Fed. Reg. 74,709; 74,740 (Dec. 6, 2022).

<sup>117</sup> 87 Fed. Reg. 74,740 (Dec. 6, 2022).

<sup>118</sup> 87 Fed. Reg. 74,740-74,743 (Dec. 6, 2022).

<sup>119</sup> 87 Fed. Reg. 74,743-74,744 (Dec. 6, 2022).

defined.<sup>120</sup> This still leaves states the challenge of proposing regulations that accommodate a speculative, and likely redundant, application process.

Commenter (2193-CARB) continues, to further streamline the process, any already approved alternatives to OGI and M21 inspections should be maintained in the Emissions Measurement Center as a supplement to the presumptive standards by EPA to prevent unnecessary applications during the CAA 111(d) Plan drafting process. Broad applicability is unnecessary when the technology's requirements are being included on the website. While the commenter applauds EPA for its vision of allowing newer and better technology in the future, it does not make sense for entities to apply for approval of technologies that have already been approved for another entity. If states are to submit their plans in an efficient manner, there must be clear and consistent guidelines to follow in the presumptive standards.

Commenter (2193-CARB) goes further, maintaining the EMC website in this manner alleviates EPA from having to regularly approve or reject proposed alternatives on a case-by-case basis that EPA has already vetted and approved. Instead, states and entities can quickly check the website and determine a technology's applicability based on the requirements prior to considering whether an application is necessary. For instance, it appears from the proposed rule that quarterly OGI inspections are preferred, but quarterly M21 inspections or quarterly advance measurement technology inspections with OGI monitoring would both be approved alternatives that EPA may set requirements for in the Emissions Measurement Center website.<sup>121</sup> Clearly identifying the alternative inspection methods with the requirements, despite an analysis of whether they are "broadly applicable", as supplements to the presumptive standards provides the states a more expedient manner to determine whether a particular method is within the presumptive standards when drafting their CAA 111(d) Plans. A state's ability to determine presumptive standards quickly and efficiently with respect to facility inspection, without unnecessary applications, ensures well-drafted 111(d) Plans that better meet EPA's proposed EGs and therefore better reduce GHG and VOC emissions.

Response II-5-237: EPA recognizes the comment. All the alternative test methods (site-specific and broadly applicable) will be available to view on the submittal website. The submission and review process will be transparent, allowing the ability for users to search and view both site-specific and broadly applicable application materials (excluding CBI) that are approved, pending and denied.

Comment: Commenter (2326-AXPC) argues their failure to provide specific comments should not indicate support or lack of concern with a particular provision. The commenter supports many of the comments related to alternative leak detection technologies made by its fellow trade associations, particularly the API.<sup>122</sup> In general, the commenter does not believe that EPA's proposal provides a workable or efficient alternative leak detection program that operators could utilize in any significant way. The commenter and its members strongly support the ability to use alternative leak detection technologies under the rules and contend that many of these technologies are at least as effective as OGI because they can potentially capture more

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<sup>120</sup> 87 Fed. Reg. 74,746 (Dec. 6, 2022).

<sup>121</sup> 87 Fed. Reg. 74,741-74,742 (Dec. 6, 2022).

<sup>122</sup> See API Supplemental Proposal Comments §3.0.

significant leaks more quickly and the screening technologies can obtain information on a greater percentage of facilities faster than an operator can accomplish with optical gas imaging. And more will come, as operators are working to further develop technological capabilities in this area. Thus, EPA's alternative leak detection program needs to be adopted in a manner that ensures that a range of technologies can be economically used now and that new technologies that become available can also be utilized. However, it must be structured significantly differently from the current alternative technology approval process to facilitate use of such devices.

Response II-5-238: EPA acknowledges the commenters input.

Comment: Commenter (2202-TXOGA) believes the rule should clarify that commercial availability of alternative technologies applies to underlying components and does not bind operators to purchase whole systems from third parties.

Commenter (2202-TXOGA) notes in the November 2021 proposal, EPA solicited data on the current detection sensitivity of commercially available methane detection technologies as deployed, as well as other data that could be used to support consideration of a different minimum detection threshold. In the proposed December 2022 changes, in an effort to streamline the approval process and reduce the time needed for processing these request for alternative test methods, EPA proposes pre-qualifications for those requesting approval of their technology; these pre-qualifications include; “(4) the technology must be commercially available, meaning it has been sold, leased, or licensed, or offered for sale, lease, or license, to the general public.” EPA is soliciting comments on how it has characterized the pre-qualifications in its proposal and whether any additional pre-qualifications may be appropriate. EPA must clarify that when it refers to the commercial availability of alternative leak detection technologies, it means that the underlying hardware components are “commercially available,” and that EPA does not mean that operators are bound to purchase certain whole package technologies from third parties that are approved by EPA. As industry practices and leak detection technology evolve, operators will likely be involved in the development of systems to more broadly detect and respond to emissions.

Commenter (2202-TXOGA) argues EPA needs to clarify the requirement for “commercially available” in a way that facilitates use of commercially available components in leak detection systems, while providing flexibility for operators to develop and build leak detection systems to fit varying operational scenarios. These could include systems that, while made up of commercially available components, may not be sold commercially as a whole package.<sup>123</sup>

Response II-5-239: EPA intent of the “commercially available” provision was a hedge to ensure only fully developed technology would be submitted to EPA for review and we did not consider owners and operators would develop their own proprietary solutions. EPA has revised the final rule to no longer include the commercially available requirements.

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<sup>123</sup> This request is consistent with EPA's overall goal of advancing technologies, while also minimizing costs.

### ***5.10.3 Flexibility in Alternative Test Method (ATM) Process***

Comment: Commenters (2184-PSR, 2203-Ceres, 2213-Oxy, 2235-SLB, 2354-Business Roundtable, 2383-Baker Hughes) express support for EPA's proposal to streamline the use of alternatives technologies via an ATM approval process.

Commenter (2184-PSR) asks the EPA to provide industry flexibility to use innovative and cost-effective methane detection technologies, and a streamlined process for approving new detection methods as they become available.

Response II-5-240: The submission requirements for alternative methane measurement technology are outlined in Section X.B.3 and XI.B.3 of the preamble of the final rule. All alternative methane measurement technology for use in this NSPS and/or EG will be reviewed by the EPA.

Comment: Commenter (2354-Business Roundtable) observes that EPA has recognized that technology to detect methane emissions is rapidly advancing.<sup>124</sup> This success has been the result of timely Department of Energy and ARPA-E research funding, EPA voluntary programs in which many Roundtable members have participated, private-public research partnerships involving the oil and gas industry and the federal government, and U.S. businesses marshalling talent and resources to address the challenge of climate change. The result is that the U.S. leads the way in developing new technology to identify and reduce fugitive methane emissions. This technology is improving every day.

Commenter (2354-Business Roundtable) has long advocated for regulatory flexibility to encourage innovation and the development of cost-effective solutions to meet regulatory objectives.<sup>125</sup> Overly prescriptive, inflexible regulations discourage the development of innovative technologies that can generate greater emissions reductions and reduce compliance costs.

Commenter (2354-Business Roundtable) indicates that while EPA is to be commended for building in and clarifying regulatory flexibility to incentivize the introduction of newer, more effective and potentially less expensive technologies, the significantly elevated frequency required for utilizing alternative technologies and the process for approving these technologies is still more cumbersome and less predictable than it should be. The requirement to resubmit technology approval applications that require additional information following EPA's 270-day window for testing new technologies,<sup>126</sup> thereby resetting the 270-day clock, for example, will unnecessarily lengthen the approval process for new technologies. While the commenter appreciates the essential role EPA plays in ensuring only effective technologies are approved for use, more flexibility is needed if the objective is to accelerate the use of effective and efficient new technologies. If EPA decides additional information is required to support an application, a

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<sup>124</sup> 86 Fed. Reg. 63147.

<sup>125</sup> Business Roundtable, *Achieving Smarter Regulation* (September 2011), available at: 2011\_09\_BRT\_Achieving\_Smarter\_Regulation.pdf

<sup>126</sup> Proposed regulatory text, §60.5398b(d), "Alternative Test Method."

better approach would be to stay the 270-day clock until the information is provided rather than require applicants to submit a new application and restart the review period.

Commenter (2354-Business Roundtable) urges EPA to provide a clearer, more expeditious and more certain pathway for the approval of innovative technologies that can be credibly verified to be as effective as those prescribed for leak detection and monitoring and consider technology needs for additional related rulemakings.

Response II-5-241: Thank you for your comments. Per the final rule, EPA will conduct a completeness review within 90 days of submission receipt. If the completeness requirements are not met, the requestor will be notified and may choose to revise the information and submit a new request. Section X.B.3 and XI.B.3 of the preamble of the final rule includes description of all submission requirements that are necessary for a submission to be considered complete.

Comment: Commenters (2363-CEMC, 2448-Project Canary) commend the EPA's ambition to streamline the approval process for proposed alternative test methods provided in §60.5398b(d), including acknowledgement of receipt of the request within 14 days and a completeness determination within 90 days of receipt. However, the commenters have concerns regarding the completeness determination process, and are providing the following comments.

Commenters (2363-CEMC, 2448-Project Canary) appreciate the EPA's planned completeness determination and notification process outlined in §60.5398b(d)(1)(ii); however, the commenters believe that without well-defined detail of the information EPA expects to see in a request for alternative test methods, there will be unnecessary delays within the approval process. Commenters (2363-CEMC, 2448-Project Canary) agree in concept with EPA's list of necessary information for consideration of an alternative test method provided in §60.5398b(d)(2) and §60.5398b(d)(3); however, the current proposal is vague when defining specific data necessary to review and approve a technology under these provisions.

As such, commenters (2363-CEMC, 2448-Project Canary) encourage the EPA develop, specific for technologies requesting an alternative test method under this subpart, a thorough and complete checklist of all information EPA will expect when considering a completeness determination, as well as final approval. A detailed checklist will help applicants ensure that all necessary information is included in each request, while expediting EPA review of said applications, helping streamline the approval process.

Commenters (2363-CEMC, 2448-Project Canary) are also providing comments regarding the initial review for completeness described in §60.5398b(d)(1)(ii). The requirement currently states:

If the request is deficient, meaning the requirements of in paragraphs (d)(2) and (3) were not met, the request will be denied, and the Administrator will notify the requestor in writing. The requestor may choose to revise the information and submit a new request for an alternative test method.



As written, if a request for approval were denied because it was deficient, the requestor would need to submit a new request for approval with appropriate revisions, restarting the 270-day conditional approval. Without a specific and detailed application checklist, as described above, commenters (2363-CEMC, 2448-Project Canary) believe there is too much ambiguity regarding what a request must include in order to be determined complete. This is particularly important because if a request is deemed incomplete, a completely new request must be submitted, inevitably delaying the process for approval of alternative technologies.

Commenters (2363-CEMC, 2448-Project Canary) also encourage EPA to provide reasonable timeframes for requestors to respond to questions and/or requests for additional information related to a request for an alternative test method, prior to denying such request. This clarification is consistent with EPA's practice. For example, in the ALT-150 approval letter, the requestor submitted additional information twice before approving the application.

For the reasons discussed above, commenters (2363-CEMC, 2448-Project Canary) recommend the following revision to §60.5398b(d)(1)(ii):

If the request is deficient, meaning the requirements of in paragraphs (d)(2) and (3) were not met, the request will be denied, and the Administrator will notify the requestor in writing. The requestor may choose to revise the information and submit a new request for an alternative test method. The new request will not restart the 270-day period provided in subparagraph (iii).<sup>127</sup>

Response II-5-242: EPA agrees that it is important to communicate our needs in order to streamline the review process. The final rule includes detailed submission requirements. A guidance document supplements the details outlined in the rule. It is the responsibility of the submitter to provide all of the required information. If the submitter fails to provide all the information requested by EPA, the request can be withdrawn by the submitter or, if necessary, denied by EPA. If the alternative method is resubmitted, the 270-day review period will restart at day 0. The review for completeness, done within 90 days, will give the submitter ample feedback regarding what information or data their submission is missing.

Comment: Commenters (2298-Pioneer, 2342-EELP, 2383-Baker Hughes, 2458-MiQ) urge EPA to incentivize operator use of advanced technologies by consistently improving its data inputs to better reflect advanced technologies' capabilities compared to BSER in realistic conditions. EPA should regularly issue guidance with the most recently approved modeling versions and peer-reviewed studies that requestors can use as inputs.

Response II-5-243: EPA acknowledges the input from the commenters.

Comment: Commenters (2298-Pioneer, 2342-EELP) state EPA should incentivize operator use of advanced technologies by consistently improving its data inputs to better reflect advanced technologies' capabilities compared to BSER in realistic conditions. Most importantly, EPA should clarify how it will conduct its review of applications to focus initial efforts on test methods that have already been established as commercially and operationally viable so that the

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<sup>127</sup> See ALT-150 Approval Letter, p. 1.

most promising technologies can be deployed as quickly as possible. For example, EPA should consider how it might prioritize such applications and request information that might help expedite certain test methods, including other jurisdictional approvals, industry sponsors, and/or commercial availability.<sup>128</sup>

Response II-5-244: EPA thanks you for your comments. The final rule includes detailed submission requirements for alternative methane technology methods. All submissions will go through the same review process. Priority will not be given to any submissions.

Comment: Commenter (2458-MiQ) states to incentivize the continued adoption and use of advanced screening technologies, the commenter recommends that EPA dedicate resources to the testing and approval process for advanced monitoring technologies, per the process outlined in the supplemental proposal. OGI efficacy and inspection frequency should also be updated on an annual basis using applicable new research. This research could, for example, include studies of the comparative effectiveness of different monitoring technologies (both new and existing).

Response II-5-245: EPA recognizes the input from the commenter.

Comment: Commenter (2383-Baker Hughes) supports the alternative test method as defined in the proposed in NSPS Subpart OOOOb and EG Subpart OOOOc, believing these provisions will stimulate continuous improvement and innovation in emission detection and control technologies.

The commenter (2383-Baker Hughes) notes that innovation will be the key to cost-effectively reducing venting and fugitive emissions from the oil and gas sector. While technology and practices exist today to begin managing this issue, continued progress is necessary to drive the emission reductions necessary to make a material impact. The commenter believes EPA should ensure that regulations do not stand in the way of that innovation. Methane regulations must be designed to both foster and accommodate future innovative technologies and practices. Therefore, it is imperative that the approval process for new emission monitoring, quantification and mitigation technologies be efficient, flexible, well-defined, and open to a broad range of potential applicants including technology providers. The commenter believes the statement in §60.5398b meets the mark: “Any entity meeting the requirements in paragraph (d)(2) of this section may submit a request for an alternative test method.” The commenter is also supportive of the requirements in §60.5398b(d)(2) defining the eligibility for entities wishing to submit an alternative test method for consideration. These provisions support innovation from the range of potential companies and organizations developing commercial solutions to methane emission detection and measurement.

Response II-5-246: Thank you for your comments. EPA agrees that innovation and improvement is important. The final rule includes well defined submission requirements so a broad range of applicants can be reviewed by EPA as efficiently and effectively as possible.

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<sup>128</sup> See AIMM Guidance & Procedures, p. 3-4.

#### ***5.10.4 FEAST Model Results, Matrix Approach, and State CAA 111(d) Plans***

Comment: Commenter (2235-SLB) recommends that in addition to the provided matrices, requestors be allowed the option to submit FEAST models with limited modifications to provide for combinations of alternative technology or threshold detection edge cases for review and approval under the alternative test method approval process included in the Supplemental Proposal.

Commenters (2298-Pioneer, 2363-CEMC, 2448-Project Canary) believe EPA should make clear that as part of alternative test method approval process, site-specific emission monitoring plans, or state CAA 111(d) plans, entities can use the most recent publicly available versions of FEAST and other models, as well as recent peer reviewed studies specific to basins within that state as modeling inputs. This way, EPA can ensure the requirements for advanced technologies reflects the best information available. For example, a state, or a group of states in a single basin, may want to submit a 111(d) plan that relies on basin specific emissions data to enable the deployment of advanced technologies best suited to reduce emissions in that area provided the emission reductions are consistent with BSER. EPA should clarify that states have the flexibility to incorporate such tailored modeling, subject to EPA approving such a plan as “satisfactory” in meeting the requirements of CAA section 111(d) and all other applicable equivalency requirements.

Response II-5-247: EPA acknowledges the input. EPA does not intend to evaluate any revisions to the matrix framework for the NSPS, however as part of the state plans in the EG, it would be appropriate for them to evaluate their own models, reflective of the oil and gas facilities found in their jurisdiction.

Comment: In response to EPA's request for comment,<sup>129</sup> commenters (2298-Pioneer, 2342-EELP) agree with EPA's recommendation to allow operators to utilize the matrix to comply with CAA section 111(h)(1) and to approve alternative test methods under 40 CFR §60.8(b)(3). Enabling operators to deploy technologies meeting the specifications of the matrix will encourage greater use of alternative test methods that can better detect emissions and therefore result in greater emission reductions than requiring operators to only use OGI or Method 21.

Commenters (2298-Pioneer, 2342-EELP) note EPA proposes the BSER for the fugitive emissions subcategory to be combinations of OGI and AVO work practice standards<sup>130</sup> under CAA section 111(h)(1).<sup>131</sup> The DC Circuit has indicated that "EPA may provide sources with multiple work practice compliance options if EPA demonstrates that at least one of these options is cost effective and 'expressly provides for the alternative in the standard.'"<sup>132</sup> Here, EPA

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<sup>129</sup> “The EPA is soliciting comment on the use of this provision at 40 CFR 60.8(b)(3) for the approval of the alternative test method for an alternative technology for measurements within the proposed alternative periodic screening approach and the proposed alternative continuous monitoring approach.” 87 Fed. Reg. 74746.

<sup>130</sup> 87 Fed. Reg. 74708-09 (Dec. 6, 2022).

<sup>131</sup> Section 111(h)(1) of the Clean Air Act allows EPA to promulgate a work practice where “it is not feasible to prescribe or enforce a standard of performance.” 42 U.S.C.A. §7411(h)(1).

<sup>132</sup> 73 Fed. Reg. 78199, 78200 (Dec. 22, 2008) (citing *Arteva Specialties S.R.L., d/b/a KoSa v. EPA*, 323 F.3d 1088, 1092 (DC Cir. 2003)).

demonstrates that BSER is cost effective<sup>133</sup> and proposes an alternative work practice (AWP) of “periodic or continuous screening with advanced measurement technology instead of OGI and AVO monitoring according to minimum detection sensitivity of technology” (the “matrix”).<sup>134</sup> This voluntary AWP is supported by precedent, as EPA promulgated OGI as a voluntary AWP to Method 21 in 2008.<sup>135</sup> EPA established the 2008 OGI AWP using modeling to demonstrate equivalency to Method 21<sup>136</sup> and is proposing to establish the matrix AWP using modeling.<sup>137</sup>

Commenters (2298-Pioneer, 2342-EELP) state EPA also proposes to approve “alternative test methods” for the matrix under 40 CFR 60.8(b)(3),<sup>138</sup> which is supported by EPA's January 30, 2007 notice in the Federal Register describing the process the agency will use to issue broadly applicable major alternative test method approvals for NSPS.<sup>139</sup> This is distinguishable from the section 11(h)(3) AMEL process, which requires notice and an opportunity for public comment,<sup>140</sup> because the matrix- as a voluntary AWP- will be promulgated under EPA's general rulemaking authority and will have gone through a notice and comment,<sup>141</sup> and the test methods demonstrate compliance with that AWP.

Response II-5-248: EPA acknowledges the commenters support of the alternative test method process.

#### ***5.10.5 Minimum Application Requirements***

Comment: Commenter (1686/2345-GHGSat) agrees with the EPA that a pre-qualification process needs to be implemented. This process will set the preliminary expectations for each technology provider allowing them to prepare and align with the requirements. Commentary for each of the four characteristics is below:

1. Requestors are limited to any individual or organization located in or that has representation in the US. The commenter believes that, while in agreement with requestors needing to have representation in the United States, this point should be elaborated further, by clarifying this requirement as to which type of entity, number of employees in the US, and good track record with the Internal Revenue Service. Also, the EPA should explain what to do in case the company just started representation in the US. The EPA should establish a minimum residency/operating time in the United States or a mechanism to account for operating time in other countries.

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<sup>133</sup> 87 Fed. Reg. 74727-35 (Dec. 6, 2022).

<sup>134</sup> 87 Fed. Reg. 74 708-09 (Dec. 6, 2022).

<sup>135</sup> See 73 Fed. Reg. 78200 (Dec. 22, 2008).

<sup>136</sup> 73 Fed. Reg. 78201 (Dec. 22, 2008).

<sup>137</sup> 87 Fed. Reg. 74741-43 (Dec. 6, 2022).

<sup>138</sup> 40 CFR §60.8(b)(3) requires that initial performance tests be conducted in accordance with the test methods “in each applicable subpart unless the administrator ... approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance.”

<sup>139</sup> 72 Fed. Reg. 4257-03 (Jan. 30, 2007).

<sup>140</sup> 42 U.S.C.A. §741 l(h)(3).

<sup>141</sup> See 71 Fed. Reg. 17,403. EPA explained that the American Petroleum Institute requested EPA approve OGI as an AWP but did not “indicate if it was invoking EPA's general rulemaking authority or the AWP provisions of CAA section [ ] 111” so EPA “treated the request as being for a general rulemaking because APJ’s request was not specific to any single source category.”

2. Requestor must have a direct knowledge of the design, operation, and characteristics of the underlying technology. The commenter believes this requirement is valid and valuable, as it can prevent the rise of opportunistic companies with limited knowledge. Nonetheless, the EPA should establish a mechanism to validate the knowledge of the underlying technology. For example, the EPA should ask requestors to provide evidence of their participation in trade shows, peer and non-peer-reviewed articles, and/or presentations associated with the underlying technology.
3. The underlying technology must have been applied to methane measurements in the oil and gas production, processing, and/or transmission and storage sectors either domestically or internationally. The commenter believes that this requirement can be coupled with requirement #2, since it is imperative that requestors not only have the technical knowledge of the technology but also that the technology has been applied in the oil and gas sector.
4. The technology must be a commercial product, meaning it has been sold, leased, or licensed, or offered for sale, lease, or license, to the general public. The commenter believes this point is valid but requires clarification as to who the general public is. A literal interpretation may disqualify most of the technologies since the general public are not necessarily interested and/or able to procure any of these technological services. The commenter recommends removing “the general public” or to further add “the general public or industry”.

Response II-5-249: EPA acknowledges the commenters support of the alternative test method process and recognizes the suggestions made.

Comment: Commenter (1686/2345-GHGSat) believes that the EPA should provide an expected timeline to conduct a pre-screening resolution. Also, it needs to explain the next steps for requestors that are not able to meet the pre-screening requirements. These next steps should consider providing a timeline for requestors to reapply.

Commenter (2348-EWTC) notes that technology approval should include proof of results, including an accredited third-party’s validation, as they relate to detecting methane leak events, field-proven evidence, and technology validation accurately capturing events per a given range of detection and quantification thresholds that are not false events. As of today, it is common in the industry to use the METEC standard from the Colorado State University in Fort Collins.

Response II-5-250: EPA recognizes the input and Section X.B.3 and XI.B.3 of the preamble of the final rule detail the requirements for the alternative test method process.

Comment: Commenter (2226-Thermo Fisher) recommends EPA clarify the terms of the second pre-qualification regarding that the technology “must have been applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally”. The commenter is unclear how a new technology can be demonstrated its application in the field without EPA designation. The commenter recommends the EPA establish a measurement technology testing facility where new technology can be demonstrated.

Response II-5-251: EPA designation is no required for use in the oil and gas sector. Only when the technology is used to demonstrate compliance with an applicable regulation under an NSPS and/or EG. This provision is in place to ensure EPA personnel will only evaluate technology that will be applied to the oil and gas sector.

Comment: Commenter (2226-Thermo Fisher) asks that EPA clarify the type of verifying information the Agency will be requesting under the proposed requirement requesting entities to provide “supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field” as part of the application. For example, clarity on if the technology must be demonstrated under controlled laboratory conditions first.

Response II-5-252: EPA has expanded and revised the criteria for submitting an alternative test method request in this rule, as detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule.

Comment: Commenter (2326-AXPC) says that EPA must clarify that when it refers to the commercial availability of alternative leak detection technologies, it means that the underlying hardware components are “commercially available”, and that EPA does not mean that operators are bound to purchase certain whole package technologies from third parties that are approved by EPA. As industry practices and leak detection technology evolve, operators will likely be involved in the development of systems to more broadly detect and respond to emissions. EPA must clarify the requirement for "commercially available" in a way that facilitates use of commercially available components in leak detection systems, while providing flexibility for operators to develop and build leak detection systems to fit varying operational scenarios. These could include systems that, while made up of commercially available components, may not be sold commercially as a whole package.

Response II-5-253: EPA intent of the “commercially available” provision was a hedge to ensure only fully developed technology would be submitted to EPA for review and we did not consider owners and operators would develop their own proprietary solutions. EPA has revised the final rule to no longer include the commercially available requirements.

Comment: Commenter (2333-LongPath) strongly recommends the following points be included in the list of required information for spatial coverage:

- What percentage of equipment is seen with each “scan”?
- How long does it take to achieve 100% coverage of all regulated equipment?
- Are there any systematic biases or blind spots in site coverage?

Response II-5-254: The intent of the spatial coverage is that you are able to measure emissions from 100% of the regulated equipment on site, EPA does not include requirements how this must be done and in reliant on the technology vendors to develop their processes so that an entire sites emissions are captured.

Comment: Commenters (2448-Project Canary, 2663-CEMC) urge the EPA to modify certain requirements of the alternative test method requirements that apply for non-entity operators. These requirements, which are found in proposed section 60.5398b(d)(2), imply that only technologies already in commercial use will be eligible for consideration. This could have the unintended effect of stifling, rather than encouraging, innovation.

Commenters (2448-Project Canary, 2663-CEMC) note proposed section 60.5398b(d)(2)(B)(ii)(B) provides that the “underlying technology” must have already been “applied to methane measurements or monitoring in the oil and gas sector either domestically or internationally.” And section 60.5398b(3)(2)(iii) requires that the underlying technology “must be commercially available, meaning that it has been sold, leased, or licensed, or offered for sale, lease, or license to the general public.” These are unreasonably limiting conditions. Notably, this proposed “commercially available” requirement imposes a higher standard on alternative test methods than the CAA section 111 test for determining whether a system is the “best system of emission reduction” that has been “adequately demonstrated.”

Commenters (2448-Project Canary, 2663-CEMC) state to be the BSER, it is not required that a technology “must be in actual routine use somewhere.”<sup>142</sup> Indeed, there are several instances in which the EPA has determined that a technology has been “adequately demonstrated” and qualifies as the BSER even where only pilot-scale data or projections were available. The Court of Appeals for the District of Columbia Circuit has upheld the validity of this approach.<sup>143</sup>

Commenters (2448-Project Canary, 2663-CEMC) argue if EPA does not require that a technology be in current commercial use to qualify as the BSER, it makes little sense for the agency to impose that requirement on what it intends to be innovative, technology-advancing alternatives to the BSER.

Response II-5-255: EPA has revised the commercially available provisions from the proposed rule as detailed in Section X.B.3 and XI.B.3 of the preamble of the final rule. The intent of the “commercially available” provision was a hedge to ensure only fully developed technology would be submitted to EPA for review.

Commenters (2448-Project Canary, 2663-CEMC) encourage the EPA to more clearly define “underlying technology” in this section. Their interpretation is that underlying technology means a physical methane detector technology which has been shown to adequately measure methane emissions, *e.g.*, laser-based, LiDAR, or metal oxide.

Commenters (2448-Project Canary, 2663-CEMC) state advanced methane emissions surveying and monitoring technologies are developing rapidly. Innovations are occurring at a brisk pace. The EPA should be open to considering as “alternative test methods” pre-commercial

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<sup>142</sup> Portland Cement Ass’n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973) (emphasis added).

<sup>143</sup> See *Sierra Club v. Costle*, 657 F.2d 298, 363-64 (D.C. Cir. 1981) (upholding standard that no plant was then meeting either at pilot- or commercial-scale, based on projected improvement in scrubber technology), 380-84 (endorsing EPA’s use of operational data from small-scale plants to project utility-scale performance of baghouse technology); *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 440 (D.C. Cir. 1973) (concluding that EPA reasonably considered “prototype testing data” and vendor guarantees to determine that system was adequately demonstrated).

technologies that can demonstrate their effectiveness to EPA through field and pilot testing. Once the technologies are approved by the agency as scientifically accurate, then it will be up to the market to determine whether they are commercially viable.

Response II-5-256: As with the previous response, the requirements that the underlying technology or technologies must be readily available for use, is to ensure they have been properly and effectively evaluated in the field for use. The alternative test provision is for evaluating technologies that are ready to be used for compliance measurements, it is unlikely that EPA will consider any technology that has not previously gone through field or pilot testing.

Comment: Commenter (1686/2345-GHGSat) agrees with the EPA with conducting an initial and complete evaluation of each alternative technology applying for alternative test method recognition. Therefore, the pre-screening process should partially address the requirements of this evaluation. The commenter believes that an effective emissions detection system needs to simultaneously satisfy the following requirements:

1. Well-characterized detection limit based on a POD curve.
2. Well-characterized, high specificity (low rate of false positives).
3. Well- characterized quantification accuracy.

Commenter (1686/2345-GHGSat) is providing comments on each of the five requirements currently listed in this proposed rule (more specific information on these comments can be found in the commenter's letter).

1. The desired applicability of the technology (*i.e.*, site-specific, basin-specific or broadly applicable across the sector).
2. A description of the measurement system.
3. Supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field.
4. A detailed description of the alternative testing procedure(s), including data quality objectives to ensure the detection threshold(s) are maintained and procedures for a daily verification check of the measurement sensitivity under field conditions.
5. Standard operating procedures consistent with the EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control.

In addition to these requirements, commenter (1686/2345-GHGSat) believes that the agency should also indicate if the requestor needs to wait until a Notice of Availability has been published in the Code of Federal Regulations to start offering the service to meet regulatory requirements. The commenter understands that the publication of Notice of Availability in the Code of Federal Regulations could take time, so the commenter would like to propose that the EPA publishes any approved alternative test method in the EPA's Air EMC website. That way, operators that are interested in employing an alternative technology for regulatory purposes can identify the approved alternative test method by visiting the EPA's EMC website and confidently procure the approved services.



Response II-5-257: EPA has developed a web app to support the alternative test method process as found at <https://www.epa.gov/emc/oil-and-gas-alternative-test-methods>. A list of all approvals will be posted on this webpage.

Comment: Commenter (2340-Honeywell) believes that ATM approvals should use standardized, independent verifications of the accuracy of methane detection technologies, and should begin prior to the finalization of the rule. The alternative test method approval process should hold all continuous monitoring systems to similar, independently verified accuracy and reliability standards based on real-world deployment conditions so as to (a) ensure accurate emissions detection and equivalency to BSER, and (b) provide an even playing field for the validation of different technologies which may otherwise be biased by varying lab testing conditions. Further, the final rule should allow for streamlining of the alternative test method approval process (*e.g.*, by allowing submission of materials prior to publication of the final rule), given that approval is critical in order for technologies to be available to regulated parties as soon as possible.

Response II-5-258: EPA acknowledges the input from the commenter, EPA has expanded the and revised the required information a person must submit when requesting an alternative test method as described in Section X.B.3 and XI.B.3 of the preamble of the rule.

Comment: Commenters (2342-EELP, 2363-CEMC) indicate that as EPA evaluates these alternative test methods for equivalency, it is critical that EPA ensure that any approved work practice standards require operators to deploy the technology in scenarios that were evaluated by EPA. Therefore, EPA should require requestors to submit supporting materials that demonstrate the equivalency of the advanced technology in a range of operating conditions to ensure the technologies are deployed in a manner that appropriately detect emissions in the field under different conditions. The commenter recommends that EPA refine the information needed for considering and approving methane detection test methods to complete the test method standard operating procedures in EPA's preferred Environmental Monitoring and Management Council Methods Format:

- Most advanced methane detection technologies require numerous elements to confirm a detection, including specific technology hardware, procedures for using the technology to detect methane emissions, and software and procedures for processing resulting data from binary data to data that confirms a "detection". EPA should clarify which of these elements it is approving in an "alternative test method" and request information on each of those elements that it is intending to approve in the alternative test method.
- EPA should clarify what information requestors should submit for EPA to approve the "operating window" and technology settings in which the specific test method will meet the matrix requirements. The operating window within the work practice standards should prescribe the necessary environmental conditions in which operators may monitor with the specific test method including conditions related to weather, topography, daylight, windspeed, temperature, humidity, sunlight, and ground cover.
- EPA should clarify that the alternative test method applications must include technology-specific work practice standards that establish the deployment configuration to demonstrate equivalency. For example, continuous monitors will require information on

spatial location and number of sensors and aerial monitors will require information on how high above the site and how quickly the monitor can fly.

- EPA should require that companies submit results of testing to demonstrate equivalency through blind testing by a qualified third party applied under controlled conditions and in the field, and across a spectrum of emissions sizes. In guidance, EPA can specify certain testing facilities to conduct controlled testing.
- EPA should require companies to submit information on the test method's spatial and temporal coverage as well as its ability to localize an emission detection and any other information to help EPA require appropriate response requirements to replace a full site wide OGI sweep.

Response II-5-259: EPA acknowledges the input from the commenter, EPA has expanded the and revised the required information a person must submit when requesting an alternative test method as described in Section X.B.3 and XI.B.3 of the preamble of the rule.

Comment: Commenter (2405-Bridger) states the Proposed Rule enables the application of advanced technologies for regulatory compliance through approval as an alternative test method. Approval is contingent on demonstration that the “technology meets the desired detection [sensitivity] threshold(s) as applied in the field.”<sup>144</sup> The commenter encourages technology approval based on field performance and supports detection sensitivities being defined at 90% PoD. In addition, the commenter recommends that inputs used to determine equivalence between emissions monitoring approaches should also represent technology field performance. For OGI, studies under realistic but controlled conditions found that experienced surveyors achieved 90% PoD for ~135 g hr<sup>-1</sup> emission rates under the study conditions.<sup>145</sup> Meanwhile, less experienced surveyors never achieved 90% PoD at any emission rate studied. The study participants knew that there would be emissions to find and often exhibited a competitive spirit, which is different from field operations. The performance indicators from this study are different from the 60 g hr<sup>-1</sup> (100% PoD) detection threshold that was used for OGI within the FEAST simulations that supported equivalency demonstration in the Proposed Rule.<sup>146</sup> Updating this input could improve the correspondence between FEAST simulations and the real-world emissions reductions that can be achieved using OGI for emissions monitoring. An empirical study of emissions detected by Bridger's Gas Mapping LiDAR™ (GML) technology estimated that GML detected 18× the volume of emissions detected by OGI,<sup>147</sup> highlighting the importance of accurately representing the field performance of OGI to ensure that different emissions monitoring approaches are evaluated on a level playing field.

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<sup>144</sup> Proposed 40 CFR 60.5398b(d)(3)(iii).

<sup>145</sup> Zimmerle, D. et al. Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. *Environ Sci Technol* 54, 11506–11514 (2020).

<sup>146</sup> US EPA. Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS) 40 CFR Part 60, subpart OOOOc (EG). (2022).

<sup>147</sup> Tyner, D. R. & Johnson, M. R. Where the Methane Is - Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data. *Environ Sci Technol* 55, 9773–9783 (2021).

Response II-5-260: EPA acknowledges the input from the commenter, EPA has expanded the and revised the required information a person must submit when requesting and alternative test method as described in Section X.B.3 and XI.B.3 of the preamble of the rule.

#### ***5.10.6 ATM Approval Process***

Comment: Commenters (2336-CEMC, 2402-DGCC, 2448-Project Canary) emphasize that the effectiveness of the EPA's proposed program to allow and promote the use of advanced methane detection technologies will depend critically on the EPA's ability to efficiently and timely approve alternative test methods. Operators will not be comfortable investing in and using alternative technologies unless and until they have certainty that the technologies can be used for compliance. The commenters support the defined 270-day deadline for approvals of requests for alternative test methods.

Commenter (2298-Pioneer) expresses that the ATM approval process should enable expeditious and thorough review of advanced technologies. The commenter supports EPA's approach to approving advanced technology using the ATM approval process under 40 CFR §60.8(b)(3), which complements the matrix approach to enable use of advanced technologies. The commenter also supports EPA's proposal to conditionally approve applications within no more than 270 days to ensure that technologies can be deployed in a timely manner. However, to enable EPA's efficient review of applications, the commenter urges the agency to clarify, either in the Final Rule or in subsequent guidance, additional detail to ensure applicants provide EPA the information it will need to approve qualifying technologies as efficiently and expeditiously as possible.

Response II-5-261: EPA recognizes the commenter's support for the rulemaking. Detailed submission requirements are included in Section X.B.3 and XI.B.3 of the preamble of the rule.

Comment: Commenters (2283-Endeavor, 2301-U.S. Chamber of Commerce (USCC)) support EPA's proposal to allow operators to use a broader range of alternative technologies that goes beyond AVO inspections and OGI.<sup>148</sup> Such flexibility will spur continued innovation within the oil and natural gas sector. The commenter specifically supports EPA's proposal to allow approval of alternative test methods for alternative advanced technologies<sup>149</sup> and recommends that EPA work to create a fast and efficient system that allows for timely approvals that are not overly burdensome to those seeking approval.

Commenters (2254-PBPA, 2283-Endeavor, 2301-USCC) support EPA's proposal that others (not just owners/operators) be allowed to propose alternative test methods, they recommend shortening the EPA's approval deadline for applications from 270 days to 180 days in order to

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<sup>148</sup> Id. at 74,741–44.

<sup>149</sup> Id. at 74,745–46.

further encourage innovation and prevent regulatory bottlenecks from stalling the use of new technologies.<sup>150</sup>

Commenter (2283-Endeavor) argues by shortening and simplifying the approval process, EPA can encourage new, cost-effective solutions that will benefit the environment, the economy, and the public. The commenter also supports EPA's proposal that others (not just owners or operators) be allowed to propose alternative test methods. Upstream producers frequently work with contractors for services, including for fugitive emissions monitoring, and it makes sense to allow entrepreneurs who wish to provide new, innovative services to be in a position to seek approval on their own.

Response II-5-262: EPA recognizes your support of the rule. The final rule includes detailed submission requirements, as described in Section X.B.3 of the preamble of the final rule. EPA has determined 270 days will provide enough time to rigorously evaluate the influx of all alternative methane technology requests and that expediting this timeline may be detrimental to the evaluation process.

Comment: Commenter (1686/2345-GHGSat) believes that the total proposed timeframe is adequate to conduct a thorough review and determination of the proposed alternative technology, which will then be translated into an alternative test method. Nonetheless, the commenter believes that the EPA should associate timelines for each of the different milestones the EPA is intended to establish. On that note, such milestones should be described a priori so that requestors can plan accordingly.

Commenter (1686/2345-GHGSat) suggests the creation of a parallel approval mechanism for requestors that have already been approved but now are bringing to the market an improved or new version of the technology. The idea is to streamline the process and fast track any applicable milestones that are not modified by the new technology.

Response II-5-263: EPA acknowledges the input from the commenter, EPA is finalizing two milestones in the process, a completeness of submittal checks at 90 days and the date in which the EPA must complete our evaluation, at 270 days. As it regards to modifications to an already approved technology, the same timetables are maintained, however EPA expects those evaluations to be concluded in a shorter time frame.

Comment: Commenter (2333-LongPath) strongly suggests that EPA define a process and maximum timeline for the approval of minor amendments to applications. The field of advanced technologies changes extremely rapidly, and operators need to continue to use the best-in-class of monitoring as it advances. Therefore, the commenter suggests a maximum time period of 30 to 60 days for approval of minor amendments, such as technology, algorithm, software, or methodological updates.

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<sup>150</sup> Id. at 74,760–41 (expansion of applicants beyond owners and operators); id. at 74,746 (270-day deadline for conditional approval). Alternatively, the commenter (2301-USCC) recommends allowing for conditional approval of technologies EPA recognizes to be in wide-use during the 270-day approval period.

Response II-5-264: EPA acknowledges the input from the commenter, as it regards to modifications to an already approved technology, the same timetables are for initial approvals for modifications, however EPA expects those evaluations to be concluded in a shorter time frame.

Comment: Commenter (2227-WEA) notes that the concept and intent of the alternative periodic screening approach and survey matrices is sound. Operators appreciate the inclusion of the matrices, yet there is still concern that the proposed frequencies will not adequately promote the use of alternative technologies.

Commenter (2227-WEA) expresses concern with the proposed nine-month approval process for technologies especially when NSPS OOOOb becomes effective and the burden that could be created by multiple approaches. Operators may have to accommodate dual programs such as conventional OGI and an alternative technology, so pre-approval of alternative technologies would help alleviate what could be a significant burden. Validation of advanced methane detection technologies should be done quickly outside of the NSPS and EG, but to promote adoption of advanced technologies, the approval process should be streamlined, particularly for technologies EPA recognizes to be in wide use today. EPA should shorten the duration of review and approve such technologies or allow conditional approval of such technologies (without risk of retroactive non-compliance) until EPA has rendered its final decision.

Response II-5-265: All technologies must undergo the same review process. EPA has determined 270 days will provide enough time to rigorously evaluate the influx of all alternative methane technology requests and that expediting this timeline may be detrimental to the evaluation process.

Comment: Commenters (2254-PBPA, 2363-CEMC, 2402-DGCC, 2448-Project Canary) support the proposed approach of providing a “conditional approval” if the agency has not acted on a request by the 270-day deadline. This approach could allow an operator to go forward with use of an alternative test method with the understanding that the EPA has not yet taken final action on its review. It would also ensure that unforeseen agency delays do not impede deployment of these very promising technologies.

However, commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) note that the “conditional approval” concept will only meet the objective of promoting deployment if the risk to the operator is understood and manageable. To this end, the commenters urge the EPA to consider certain clarifications in proposed section 60.5398b(d)(1)(iii).

First, commenters’ (2363-CEMC, 2402-DGCC, 2448-Project Canary) understanding of the language in section 60.5398b(d)(1)(iii) is that the 270-day clock starts from the date of the “request” under section 60.5398b(d)(1), and not the date that the EPA determines “completeness” pursuant to section 60.5398b(d)(1)(ii). This approach is rational in the commenters’ view, and they urge the EPA to confirm this interpretation.

Second, commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) urge the agency to provide more detail on how “conditional approval” under section 60.5398b(d)(1)(iii) would

work. Absent this additional detail, operators may be reluctant to use methods subject to “conditional approval” status.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) express that it is not clear what consequences follow if the EPA subsequently denies approval for an alternative test method that had “conditional approval” status. The commenters assume that such an agency action does not result in some form of retrospective liability for an operator that used the “conditionally approved” alternative test method in lieu of the requirements for fugitive emissions components affected facilities in §60.5397b and covers and closed vent systems in §60.5416b. Were such retrospective liability to apply, it would defeat the agency’s intentions for “conditional approval” because it is highly unlikely that any operator would use an alternative test method subject to that kind of risk. For these reasons, the commenters urge the EPA to make clear that an operator is not subject retrospective liability under such circumstances.

According to commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary), operators will also want to know what prospective obligations they have in the event the EPA ultimately rejects a “conditionally approved” alternative test method. The commenter (2448-Project Canary) assumes that, in such a scenario, the operator must switch either to an approved alternative test method or to the OGI-based program required in §60.5397b or to closed vent systems as detailed in §60.5416b, as applicable. The commenter (2301-CEMC) urges the EPA to provide a reasonable grace period for the operator to modify and implement its plan for monitoring fugitive emissions, including obtaining needed equipment and contracting with service providers. For example, the EPA could establish a deadline identical to the deadline that applies under §60.5397b(f) for an initial monitoring survey of a new or modified well, *i.e.*, within 90 days of the agency’s notification.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) add that a similar grace period should apply in the event that the EPA approves an alternative test method that had been subject to “conditional approval” but imposes work practice requirements that vary from the original alternative test method submittal. For example, the agency could approve a particular kind of continuous monitoring technology but require more sensors than operators were using pursuant to the “conditional approval.” In such circumstances, the operators could benefit from a period of time to obtain the additional sensors needed to ensure full compliance. Here again, a 90-day period would be appropriate.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) urge the EPA to consider the foregoing clarifications and modifications to the “conditional approval” approach because they will meet the agency’s objectives of ensuring that unforeseen agency approval delays do not discourage operators from using highly promising advanced methane detection technologies. While any “conditional approval” inherently subjects an operator to some risk, the agency has an interest in ensuring that the risk is manageable.

In addition, as discussed in other sections in these comments, commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) request that the agency structure the approval process so that it is more streamlined for: (1) technologies already in commercial use and (2) technologies already approved by states.

Response II-5-266: EPA recognizes the commenter's input. The final rule includes detailed submission requirements, as described in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA has determined 270 days will provide enough time to rigorously evaluate the influx of all alternative methane technology requests and that expediting this timeline may be detrimental to the evaluation process.

Comment: Commenter (2333-LongPath) indicates that it has no fundamental concerns with the proposed timeframes. However, the commenter strongly discourages leaving an unlimited timeframe for programs to remain "conditionally approved." Operators require certainty of future use to invest in the installation of fixed monitoring infrastructure. Therefore, the commenter suggests a sunset period for conditional approvals after which time they are either fully approved in final form or rejected with specific guidelines for re-submission.

Response II-5-267: The final rule has maintained the "conditionally approved" provisions from the December 2022 proposal. EPA has determined 270 days will provide enough time to rigorously evaluate the influx of all alternative methane technology requests. We do not expect evaluations to extend beyond 270 and the time limit is there to ensure the EPA provides an action upon receiving a submittal.

Comment: Commenter (2428-API) argues that technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc. The commenter suggests that to facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Commenter (2428-API) recognizes that EPA is unable to approve technologies until the rules are finalized, so the commenter proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Commenter (2428-API) notes that operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has

already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

Response II-5-268: EPA recognizes the commenter's input. The final rule includes detailed submission requirements, as described in Section X.B.3 and XI.B.3 of the preamble of the final rule. EPA will start accepting submittals for these alternative test methods on the effective date of the rule, which is 60 days after the publication in the Federal Register.

EPA does not expect evaluations to extend beyond 270, however if EPA fails to decide by that time and a technology is considered conditionally approved, it may be used for compliance purposes. If a conditionally approved or approved technology is later found to be inadequate by the EPA and we have to rescind an approval, the preceding surveys or use of the technology I still considered valid.

Comment: In place of or in addition to initial conditional approval, commenter (2428-API) recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of  $\leq 30$  kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.
- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

Commenter (2428-API) adds that an initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

Comment: Commenter (2428-API) asks that EPA clarify how the review and conditional approval process will be implemented in the following ways:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be



able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

Response II-5-269: The final rule has maintained the “conditionally approved” provisions from the December 2022 proposal. EPA has determined 270 days will provide enough time to rigorously evaluate the influx of all alternative methane technology requests. We do not expect evaluations to extend beyond 270 and the time limit is there to ensure the EPA provides an action upon receiving a submittal.

Comment: Commenter (2428-API) also asks that EPA elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

Response II-5-270: The information required for each submission is detailed in the final rule. It is the responsibility of the submitting entity to ensure they include all the requested information within 90 days of submission. The initial completeness review will provide feedback to the submitter regarding what information they are missing. If the submitter does not provide the request information within the 90 days of initial submission, the submitter may be asked to withdrawal their application or be denied. The intent of this process is to ensure as many applications as possible can be reviewed in a timely manner by EPA. Allowing submitters, the opportunity to delay submission of important information requested by EPA will slow the review process and may result in unnecessary conditional approvals.

Comment: Commenter (2284-Kairos) notes that EPA provided some guidance on the data requirements for alternative technologies to obtain approval to conduct regulatory inspections for the Proposed Rules. The commenter recommends EPA provide further detail on its expectations to streamline the review process for both technology developers and for the agency itself. This will lead to faster, more predictable outcomes that consume fewer resources on all sides.

Commenter (2284-Kairos) commissioned Highwood Emissions Management to develop a proposed framework for data needs to accurately assess alternative technology performance. The full document is available in Appendix A of the commenter’s letter, but the commenter provides a brief summary here. The goal is to balance the need for clear, transparent, and rigorous standards to ensure an aerial screening program will effectively and consistently eliminate emissions, without creating excessive administrative or technical burden for these programs. The commenter’s suggested aerial screening program framework follows a similar structure to the proposed Appendix K for OGI techniques. While the guidance provided by the commenter here is directly applicable to aerial screening surveys, many of the same data quality indicators, testing protocols, and documentation requirements will be relevant for other technology deployment methods (e.g., continuous monitoring systems).

Commenter (2284-Kairos) states the key elements are:

- Testing should be conducted with an independent third party where possible but is not explicitly required; all testing should be conducted using a well-documented, transparent plan with unbiased results and data quality indicators.
- Testing should be performed at the sensor model level– not every instrument of the same design needs to go through independent third-party testing. Note that this does NOT mean that an instrument can forgo calibration and maintenance necessary to ensure performance aligns with expected performance from the sensor model–technology developers must outline how they verify performance of additional sensors within the same model.
- Model testing shall establish probability of detection and an operating envelope including:
  - Flight parameters; and
  - Meteorological conditions.
- Technology developers shall establish an equipment calibration and maintenance schedule to regularly evaluate safety, hardware and software functionality, and data quality indicators.
- Each survey must have an operations plan that describes the following:
  - Pre-data acquisition instrument performance checks;
  - Pre-data acquisition software checks;
  - Pre-data acquisition operating envelope checks;
  - Pre-data acquisition data recording check; and
  - Plan for monitoring conditions throughout the survey.
- Documentation plan for the following:
  - Coverage of facilities;
  - Adherence to operating envelope; and
  - Survey results (*i.e.*, documentation of fugitive emissions or no emissions detected).
- Operator training requirements
- Data quality indicators to confirm instrument performance during the survey
- Recordkeeping
  - Documents to be maintained; and
  - Responsible party for each required piece of documentation.

The commenter (2284-Kairos) recommends that an alternative technology work practice that includes these elements will strike the correct balance of rigor and feasibility.

Response II-5-271: EPA recognizes the commenter’s input. The final rule includes detailed submission requirements, as described in Section X.B.3 and XI.B.3 of the preamble of the final rule.

Comment: Commenters (2307-Qube, 2363-CEMC, 2402-DGCC, 2448-Project Canary) note the Supplemental Proposal does not speak to how the agency will address minor changes to an already-approved Alternative Test Method. This silence could imply that an owner or operator

who wants to use a slightly upgraded version of an already-approved technology would need to go through the full approval process outlined in §60.5398b(d)(1).

Commenters (2307-Qube, 2363-CEMC, 2402-DGCC, 2448-Project Canary) note that minor upgrades to an approved technology should not trigger the full approval process. Such an approach would be inconsistent with the agency's objective of promoting the use of innovative technologies. For example, continuous monitoring system developers and vendors, including the commenter (2402-DGCC)'s members, regularly push out updated algorithms for the technology, thereby enhancing the system performance, such as speed of quantification calculations, exception handling, connectivity improvement, and many other potential upgrades. While these updates can be as frequent as several per year, the underlying quantification calculation methodologies and practices remain the same. Requiring such minor upgrades, which don't fundamentally alter the underlying quantification methodologies, to go through the full approval process is an inefficient use of resources for the regulator and the regulated community—and it could discourage owners and operators from implementing upgrades that offer better environmental performance.

Response II-5-272: See response II-5-273.

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) recommend that the agency adopt a streamlined approval process for minor upgrades to already-approved alternative test methods. First, the EPA could define a “minor change” or “minor upgrade” as any change in the hardware or associated software of a continuous monitoring system, which may improve, but will not degrade the system's ability to meet the requirements of §60.5398b(c). Changes in hardware or associated continuous monitoring system software that do not directly impact methane emissions quantification would not require subsequent approval from the EPA. Alternatively, EPA could approve these kinds of changes when they approve an alternative methodology application. A full approval process would be inconsistent with the realities of these kinds of technology upgrades.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) say that if the agency determines it needs to have a separate approval process for minor upgrades, it could at least provide that such approvals subject to an expedited process, *e.g.*, 30 days instead of 270 days. As with the regular process, “conditional approval” would apply if EPA has not taken final action within the 60-day period (noting our recommended changes to the “conditional approval” requirements discussed in these comments).

Commenter (2235-SLB) encourages the EPA to include provisions to allow routine updates common in technologies deployment (such as software updates) to be made to approved technologies without retriggering the overall alternative technology review process.

Response II-5-273: EPA acknowledges the input from the commenters, as it regards to modifications to an already approved technology, the same timetables are for initial approvals for modifications, however EPA expects those evaluations to be concluded in a shorter time frame.

When it comes to upgrades of a system, EPA does not consider “quality of life” improvements to be a major change that would necessitate a re-submittal. Only when a major change is made to a system would a re-submittal be required including any change in the hardware that would affect a direct measurement (*i.e.*, methane concentration, wind vectors) or a change in the quantification calculation(s) that would result in a +/-5% change from the previously approved system, would a re-submittal be required.

Comment: Commenter (2405-Bridger) believes that third-party blind testing using standard protocols is necessary to provide confidence in the capabilities of methane sensing technologies. To ensure that the alternative test method approval process is transparent and upholds high scientific standards, blind testing by an approved third party should be required to demonstrate detection sensitivity. The METEC ADED initiative provides defined blind testing protocols for both continuous emissions monitoring systems and periodic screening methods. Adhering to ADED protocols presents an opportunity to achieve consistent and transparent technology approval.

Commenter (2405-Bridger) urges the EPA to require methane sensing technologies specified in alternative test method applications to demonstrate detection sensitivity performance through third-party blind testing using ADED protocols as part of approval requirements.

Response II-5-274: EPA acknowledges the recommendations. The final rule outlines requirements for published reports to be submitted as a part of the alternative technology request (see language below). While third party blind testing is not specifically required, it does represent strong supporting data. Additional guidelines regarding supporting evidence and data will be included in the guidance document.

*“Published reports (e.g., scientific papers) produced by either the submitting entity or an outside entity evaluating the submitted measurement technology that has been independently evaluated. The published reports must identify either a site-level or aggregate detection threshold and be accompanied with sufficient supporting data to evaluate whether the performance metrics of the alternative testing procedures in paragraph (d)(3)(vi)(C) of this section are adequate and the data was collected consistent with those alternative testing procedures. The supporting data may be included in the published report or may be submitted separately.”*

Comment: Commenter (2405-Bridger) believes that emission source localization capabilities should be demonstrated in the alternative test method application. Fundamental properties of methane sensing technologies include the ability to detect, localize, and quantify emissions. Localization capabilities should guide operators’ response to detection events. Efficiency is gained by being able to quickly confirm the presence of an emission, determine its cause, and initiate a response. Elsewhere in the commenter’s letter, the commenter urged the EPA to require onsite OGI follow up for periodic screening detection events only within the localization uncertainty of the methane sensing technology. Doing so requires localization precision and accuracy to be parameterized in the alternative test method application. Technologies used for periodic screening of emissions or continuous monitoring at individual well sites, compressor stations, and centralized production facilities should be able to localize emissions at least to the

site level. Improved localization capabilities should be reported as equipment group, equipment unit, and component-level precision. These designations have been accepted by the community<sup>151,152,153</sup> and should simplify onsite follow-up for detected emissions. For example, it would be simpler to use OGI to inspect an equipment group than determine a circle with a 50-foot radius that needs to be inspected. The ADED protocols that are mentioned throughout this letter provide a consistent and transparent approach to evaluating localization precision and accuracy. For a test method to be classified at a given level of localization precision, 95% of its detections should be correctly localized.

Commenter (2405-Bridger) urges the EPA to require demonstration of emission source localization capabilities for methane sensing technologies specified in alternative test method applications through third-party blind testing using ADED protocols.

Response II-5-275: EPA thanks you for your recommendations and agrees methane technology localization should be demonstrated. The final rule includes requirements for demonstrating whether a technology has facility-level spatial resolution, area-level spatial resolution, or component-level spatial resolution. The final rule also outlines different follow-up procedures based on the spatial resolution, or localization capabilities, of the technology.

Comment: Commenter (2405-Bridger) believes that methane sensing technologies need to reliably quantify emissions. In the proposed rules, mass emission rate action levels for the continuous monitoring approach assumes that the methane sensing technology accurately quantifies emissions. For example, if a fixed sensor system used for this approach returns average quantification values that are a factor of two lower than the true value, then the desired emissions reductions will not be achieved. Alternatively, if the quantification values are too high, then operators may waste time addressing negligible emissions. An alternative test method should not be approved by the EPA unless its capabilities are well represented. The commenter urges the EPA to require demonstration of emission rate quantification capabilities for technologies specified in alternative test method applications through third-party blind testing using ADED protocols.

Response II-5-276: EPA agrees that it is important to require all alternative methane technologies to demonstrate their emission rate quantification capabilities. The final rule details rigorous requirements for alternative test method submissions, including published reports and supporting data to demonstrate capabilities in the field.

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<sup>151</sup> Ravikumar, A. P. et al. Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge. *Elementa* 7, (2019).

<sup>152</sup> Bell, C. S., Vaughn, T. & Zimmerle, D. Evaluation of next generation emission measurement technologies under repeatable test protocols. *Elementa: Science of the Anthropocene* 8, (2020).

<sup>153</sup> Bell, C., Ilonze, C., Duggan, A. & Zimmerle, D. Performance of continuous emission monitoring solutions under single-blind controlled testing protocol. *ChemRxiv* (2022). doi:10.26434/chemrxiv-2022-4hc7q-v2.

Comment: Commenter (2405-Bridger) states that in order to provide stakeholders with assurance that emission monitoring achieves stated performance, monitoring methods should be routinely audited.

Commenter (2405-Bridger) notes operators, the EPA, and other stakeholders need assurance that emissions monitoring approaches continue to achieve their stated detection sensitivity. The commenter recommends that the EPA requires sensor operators to report anonymized emission rate measurements in the aggregate for each production basin on a yearly basis (past measured distributions should be a necessary, but not sufficient, requirement of approval). Reporting data for each basin individually is important because different basins can have very different characteristics including emission rate distributions, wind speeds, ground reflectivity, topography, and vegetation. After compiling data obtained from individual alternative test methods and generating emission rate distributions, statistical analysis can be performed to evaluate the detection sensitivity that was achieved during field operations.

Commenter (2405-Bridger) states measured emission rate distributions in a production basin can be fit to a suitable model probability density function (*e.g.*, functions describing lognormal or pareto distributions). At lower emission rates, where the number of emissions measured is less than the number expected based on the model probability density function, false negative detections are likely. The fit should only be applied to the part of the emission rate distribution for which the test method has a nearly 100% probability of detecting emissions. The commenter recently released a preprint of a scientific study where they performed similar statistical analysis of emission rate distributions.<sup>154</sup> The commenter refers the EPA to this publication for important details on the analytical approach.

Commenter (2405-Bridger) argues a statistical test on aggregate emission rate distributions is well suited for assessing detection sensitivity field performance for periodic screening approaches because it is simple and objective. Continuous monitoring systems may require alternative statistical analysis, but by collecting data, the EPA, operators, and other stakeholders will have the requisite inputs to objectively evaluate continuous monitor performance even if the analytical methods remain to be established.

Commenter (2405-Bridger) urges the EPA to audit the detection sensitivity achieved during field measurements taken by methane sensing technologies under approved alternative test methods. Next, the commenter recommends that the EPA requires sensor operators to report aggregate emission rate distributions which the EPA would use to evaluate the detection sensitivity achieved during field deployment on a yearly basis.

Response II-5-277: EPA recognizes the commenter's input and agrees that for many technologies, the detection threshold(s) will change based on environmental factors. EPA has revised the requirements for detection thresholds detailed in Section X.B.1, X.B.3, XI.B.1, and XI.B.3 of the preamble of the final rule.

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<sup>154</sup> Kunkel, M. W. et al. Extension of Methane Emission Rate Distribution for Permian Basin Production Infrastructure by Aerial LiDAR. (2022).

Comment: Commenter (2403-PAO) observes that EPA states that it retains authority to rescind approvals of any alternative monitoring technology. It is unclear how EPA will view companies using a technology that EPA later rescinds approval. The commenter requests EPA clarify that companies using a technology that EPA later rescinds approval for will not be held in violation.

Response II-5-278: EPA recognizes the commenter's input; The final rule states EPA has 270 days to determine if a submitted request for an alternative test method meets the requirements for compliance. If a decision is not made after 270 days, the technology will be given conditional approval status. If an approved or conditionally approved method that is being used by a company is later determined to be inadequate for compliance, the company must find a new method. All previous use of the method when it was considered "approved" or "conditionally approved" will not constitute a deviation of the standard.

Comment: Commenter (2448-Project Canary) encourages the EPA to take into consideration continuous monitoring systems that have been approved for similar purposes under state regulatory programs, at a minimum to provide expedited approval of a technology. For example, CDPHE Alternative Approved Instrument Monitoring Method (Alt-AIMM) program includes an extensive equivalency, and technology feasibility review, to ensure approved continuous monitoring systems will meet the LDAR objectives, meeting or exceeding an already robust OGI camera LDAR inspection program.

Response II-5-279: All alternative test method proposals will be required to submit materials outlined in the final rule and will undergo the same approval process.

Comment: Commenter (2196-Private Citizen) comments on continuous monitoring, stating this option is truly an evolution or paradigm shift for LDAR programs whether upstream or downstream. Though, 1 AMEL has been approved for downstream. As this AMT matures, is developed and validated to ensure equivalent emissions reductions, the process or plan required in §60.5398b(c)(2) should at a minimum:

- Any leaks found using the OGI camera through the root-cause analysis should be quantified for Mass using the Hi Volume sampler. This mass data (and distance from sensors) is essential to verify veracity of the continuous monitoring system claims of mass resolution. As well as additional data that should be used to tweak algorithms (*i.e.*, the more real data used to adjust calculation, the smarter the algorithms are) used to establish mass at the sensor. This data is critical for the evolution of this technology as an established future alternative for LDAR.
- Require semiannual Human OGI process (Appendix K or as specified in §60.5397b) if the facility were normally required to be surveyed quarterly.
- And an annual Human OGI process (Appendix K or as specified in §60.5397b) if the facility were to normally require to be surveyed semiannually.

Response II-5-280: EPA recognizes the commenter's input.

Comment: Commenter (2451-Highwood Emissions Management and Analytics Inc. (HEMA)) believes the use of LDAR modeling as part of ATM technology approvals is critical to guarantee the performance of these solutions in a broad range of conditions.

Commenter (2451-HEMA) note that diverse tools exist for modeling the performance of methane detection and quantification technologies. Use of the tools in technology approvals at a national scale is critical to provide evidence for the value of technologies under broad representative conditions. Both conventional (OGI) and emerging alternative technologies perform differently under environmental and operational conditions. Key considerations include wind speed, temperature, precipitation, expected emissions profiles, site complexities, spatial coverage, topography, ground cover, cloud cover, and more. The METEC testing facility is a critical step in exploring the performance of technologies. However, it only provides one context for testing a solution. Simulation modeling is therefore needed to enable extrapolation of performance under a broad range of conditions to provide confidence that the proposed technology and work practice meet equivalency expectations. These tools, which include LDAR-Sim, FEAST, AroFEMP, and potentially others, have been thoroughly tested and have been integral for the adoption of all new technologies in an alternative LDAR context in Alberta and Colorado to date. These tools have also been vetted in the peer-reviewed literature and have been used by industry, non-profits, and voluntary initiatives to thoroughly understand technology performance before approval is issued.

The commenter states for consideration of specific technologies that do not fit within the context of the proposed screening matrix and prescribed continuous monitoring action levels, LDAR modelling should be a required approach for equivalency demonstration during the technology and work practice evaluation.

Commenter (2451-HEMA) states the EPA should be explicit in determining what exactly is required for a technology to be approved, what modeling parameters are needed, and what defaults should be expected. Relevant critical considerations include facilities in scope, production types, geographical coverage, temporal and spatial resolution, expected emissions distributions, leak production behavior, natural leak removal behavior, weather basis and assumptions, operational envelopes, required performance metrics from controlled testing, probability of detection mechanism, and follow-up, reporting, and repair timelines. In addition, as technology capabilities and methane distributions evolve with time, the commenter suggests approval requirements, published matrixes, and other prescribed details for alternative technology approval are re-evaluated as more data is collected and there is greater confidence in the field equivalency of these programs.

Commenter (2451-HEMA) notes while there has been considerable advancement in the capabilities of LDAR models, more work is needed to improve their functionality and cross-reference their results from field work. Furthermore, consensus is needed on how to perform the modeling for different regions and environmental contexts to ensure that “apples to apples” comparisons are being made during technology approval. There is also an important educational gap due to the novelty and complexity of these models. The commenter encourages the EPA to invest resources in the LDAR modeling community to enable greater understanding, consensus, and performance of LDAR models.



Response II-5-281: EPA thanks you for your comments and recommendations. The final rule details the submission requirements for alternative test methods. Submission requirements include details relating to model parameters, spatial resolution, assumptions, etc. Submissions will be reviewed by EPA to determine whether the alternative test method meets requirements and is adequate for indicating compliance.

EPA has detailed the advance methane detection technology alternative test method program in Section X.B.3 and XI.B.3 of the preamble to the final rule.

#### ***5.10.7 Inflation Reduction Act (IRA)***

Comment: Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) state that the IRA provides support for the inclusion of the alternative test method provisions in the supplemental proposal. The text of IRA §60113 makes clear that Congress intends that there should be increasingly rigorous detection and quantification of methane emissions in the oil and gas sector. For example, §60113 requires EPA to levy the waste emissions charge on a per-ton methane intensity basis, which is not possible without highly accurate measurement of both emissions and throughput at affected facilities.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) state that the Congressional emphasis on improved quantification can also be found in the directive to EPA to develop new and improved empirical methodologies for emissions reporting under the Subpart W program. This directive makes clear that continued reliance on emission factors under Subpart W is not appropriate. Under an emissions factor methodology, two facilities with widely disparate actual emissions but similar emission factors could incur equivalent waste emissions charge liability. Such an outcome would undermine the intent of Congress to incentivize reductions through a per-ton waste emissions charge.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) add that Congress clearly intended EPA to use the funds appropriated under §60113 to financially support the deployment and adoption of the most rigorous available methane detection and quantification technologies. In particular, the appropriated funds provide a means for EPA to assist operators in progressing from periodic surveying with OGI cameras and Method 21 to more advanced and effective methane monitoring technologies.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) say that the regulatory incentive of the alternative test methods may not be sufficient for some operators—including operators of marginal wells—for whom the costs of purchasing and operating such technologies exceed the costs of OGI cameras. Many operators already have established OGI inspection programs with company owned OGI cameras and personnel, and more frequent inspections will be additive to their current LDAR programs. In certain instances, the expansion of an existing LDAR program utilizing OGI cameras, even with the need for additional cameras and personnel, will cost less than the expenditures necessary to implement a CEMS program. The funds appropriated through §60113 can supplement the regulatory incentives in the proposed Clean Air Act §111 rules to bridge this gap.

Commenters (2363-CEMC, 2402-DGCC, 2448-Project Canary) state that §60113 clearly directs EPA to use funds to aid the deployment of advanced monitoring technologies, thereby lowering their costs and expanding their availability throughout the sector. For example, §60113 (a)(3)(B) requires EPA to ensure funds are dedicated to “improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions and waste.” And §60113 (a)(3)(C) directs the agency to use funds for “supporting innovation in reducing methane and other greenhouse gas emissions and waste from petroleum and natural gas systems.”

Commenter (2402-DGCC, 2448-Project Canary) submit comments on how the EPA should implement the IRA in its response to the EPA’s request for information on the implementation of the IRA’s MERP (Docket ID No. EPA-HQ-OAR-2022-0875) (RFI). The commenter incorporates their response to the RFI by reference and attached a copy in their comment letter.

Response II-5-282: EPA acknowledges the commenters’ input.

EPA has provided responses to similar comments in Chapter 9 - Inflation Reduction Act (IRA) and Methane Emissions and Waste Reduction Incentive Program (MERP) of the Response to Comment document.

Comment: Commenter (2355-CEC) states that the recently enacted IRA is considered the most significant climate legislation in U.S. history.<sup>155</sup> The IRA reflects congressional support for regulations and policies that incentivize and promote development of climate technologies for a variety of economic sectors. In light of the Infrastructure Investment and Jobs Act (IIJA) and the IRA, technologies for decarbonizing the power sector are forecast too rapidly advance. In developing rulemakings pursuant to CAA section 111, EPA has an opportunity to align its decision-making with that congressional intent and the changing landscape by exercising its authority to promulgate standards of performance that further encourage the development and deployment of technology.<sup>156</sup>

Commenter (2355-CEC) notes D.C. Circuit has developed a robust body of case law interpreting the term “standard of performance” under section 111.<sup>157</sup> Among the factors that EPA should consider in making a BSER determination is whether the standard would effectively promote further deployment or development of advanced technology.<sup>158</sup> EPA correctly echoes this in the Supplemental Proposal by including “advancement of technology” as one of the five factors it uses to determine which are the best systems.<sup>159</sup> While the BSER must be a system of emission

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<sup>155</sup> See, e.g., White House, FACT SHEET: Inflation Reduction Act Advances Environmental Justice (Aug. 17, 2022), <https://www.whitehouse.gov/briefing-room/statements-releases/2022/08/17/fact-sheet-inflationreduction-act-advances-environmental-justice/> (“Most Significant Climate Legislation in U.S. History Delivers for Overburdened Communities”).

<sup>156</sup> See Greg Dotson & Dustin J. Maghamfar, The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act, 53 E.L.R. 10017, 10026, (2023) (“[T]he is funding provided by the IRA will allow EPA to increase the ambition of its CAA rulemakings, by lowering costs and demonstrating the feasibility of pollution control technologies.”).

<sup>157</sup> E.g., Portland Cement Ass’n v. Ruckelshaus, 486 F.2d 375, 391 (D.C. Cir. 1973) (noting that Congress did not intend to require that “the technology must be in actual routine use somewhere” and that “[t]he Administrator may make a projection based on existing technology”) (internal citations omitted).

<sup>158</sup> Sierra Club v. Costle, 657 F.2d 298, 347 (D.C. Cir. 1981).

<sup>159</sup> Supplemental Proposal, 87 Fed. Reg. at 74,820.

reduction that is “adequately demonstrated,” what is considered “adequately demonstrated” is rapidly changing as pollution control technologies are developed and deployed, especially in light of the funding and financial incentives of the IRA. Any suggestion that a system of emission reduction is adequately demonstrated only if it has been deployed on a commercial scale is inconsistent with the rate of technological advancements in the twenty-first century. In recent years, the amount of time between innovation and implementation has shortened significantly, and demonstration occurs much more quickly.

Commenter (2355-CEC) supports EPA’s approach of authorizing owners and operators to use advanced monitoring technologies by providing: (1) a performance matrix based on inspection frequency and minimum detection sensitivity and (2) a system by which owners and operators can propose individual advanced technologies that meet the specifications of the matrix as “alternative test methods” for approval by EPA. The commenter agrees with the Agency’s recommendation to allow owners and operators to use the matrix to comply with CAA section 111(h)(1) and to approve alternative test methods under 40 CFR 60.8(b)(3).

Commenter (2355-CEC) appreciates that EPA has determined that, for the fugitive methane emissions subcategory, combinations of OGI and AVO work practice standards should be the BSER.<sup>160</sup> However, technologies for detection of fugitive methane emissions are advancing rapidly. Certain technologies, used in accordance with specified work practices, can achieve better results and therefore result in greater methane emission reductions. Given the imperative under CAA section 111 for EPA to promote technological innovation, it is appropriate for the Agency to provide pathways for owners and operators to use such technologies for compliance.

Commenter (2355-CEC) adds that, in addition, the IRA includes a clear congressional directive to the EPA to promote deployment of advanced methane technologies.<sup>161</sup> Section 61103 of the IRA appropriates \$1.55 billion to EPA for such purposes as “improving and deploying industrial equipment and processes that reduce methane and other greenhouse gas emissions and waste<sup>162</sup>” and “supporting innovation in reducing methane and other greenhouse gas emissions and waste from petroleum and natural gas systems.<sup>163</sup>” EPA should complement these financial incentives with regulatory incentives.

Commenter (2355-CEC) states the approach EPA has outlined in the Supplemental Proposal is a valid use of the Agency’s authority to achieve the aim of increasing deployment of advanced methane detection technology. The D.C. Circuit has indicated that “EPA may provide sources with multiple work practice compliance options if EPA demonstrated that at least one of these options is cost effective and ‘expressly provides for the alternative in the standard.’”<sup>164</sup>

Commenter (2355-CEC) notes that the agency also proposes to approve “alternative test methods” that meet the thresholds of the matrix under 40 CFR 60.8(b)(3). The approach finds

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<sup>160</sup> 87 Fed. Reg. 74708-09.

<sup>161</sup> P.L. 117-169 (Aug. 22, 2022).

<sup>162</sup> Id. at section 60113(a)(3)(B).

<sup>163</sup> Id. at section 60113(a)(3)(C).

<sup>164</sup> 73 Fed. Reg. 78199-200 (citing *Arteva Specialties S.R.R.L., d/b/a KoSa v. EPA*, 323 F.3d 1088, 1092 (D.C. Cir. 2003)).

support in the Agency’s January 30, 2007, notice in the Federal Register outlining the process by which EPA will approve alternative test methods for NSPS. Once approved, such methods may be used any owner or operator for compliance.<sup>165</sup>

For these reasons, commenter (2355-CEC) agrees that EPA is appropriately using its authority to establish a system by which owners and operators may use advanced methane monitoring technologies as alternative test methods. Furthermore, the commenter strongly supports this approach as a means of promoting the deployment of these rapidly improving technologies.

Response II-5-283: EPA recognizes the commenter’s support of the rulemaking. We acknowledge the desire to make the use of alternative technology the BSER, however EPA currently does not have the information necessary information to make that determination.

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<sup>165</sup> 72 Fed. Reg. 4257-62 (Jan. 30, 2007). The alternative test method process is distinct from the section 111(h)(3) “alternative means of emission limitation” (AMEL) process. Under section 111(h)(3), each AMEL is subject to a notice-and-comment approval process—and may be used only at the facility for which it was approved. Here, by contrast, the matrix itself is the alternative work practice, promulgated through a rulemaking, and the alternative test methods simply demonstrate compliance with the matrix. Furthermore, approved alternative test methods may be used at multiple facilities.

## Chapter 6. Well Affected Facility and Associated Operations

### 6.1 Well Affected Facility

Comment: Commenter (2227-Western Energy Alliance (WEA)) states that the definition of a modification to an existing well should be simple and applied to the well affected facility to which a standard is applicable, not all operations involving that well facility. Though not defined by EPA, a new well would reasonably be assumed to be a well spudded after the proposed effective date of the rule. The commenter provides that a modification to an existing well should be a physical or operational change to the well that results in increased emissions. Consistent with new source performance standards (NSPS) OOOOa, the proposed NSPS OOOOb provides that a modification to an existing well occurs when an existing well undergoes a well completion with hydraulic fracturing or refracturing. The commenter does not support adding complexity to the established modification provisions for wells, such as liquids unloading operations on natural gas wells.

The commenter (2227-WEA) suggests the following:

- Make the determination of whether a modification has occurred at an existing well to be based on the changes that occur at the individual well affected facility and not in terms of all operations at the facility.
- Define a modification to an existing well as a physical or operational change that subsequently results in increased volatile organic compound (VOC) or methane emissions.
- Codify a categorical exclusion for well affected facilities subject to certain state or local associated regulations.
- Categorically exclude wildcat and delineation wells, and oil wells at sites with no natural gas takeaway capability from requirements to recover natural gas without a distinct requirement to demonstrate that takeaway is not feasible.

Response II-6-1: The well affected facility was defined in the supplemental proposal as a single well. This proposal greatly simplified the three well-related affected facilities proposed in the November 2021, which were (1) the well completion affected facility, (2) the associated gas affected facility, and (3) the well liquids unloading affected facility. The final rule retained this single simplified well affected facility definition. There are separate proposed standards for well completions, associated gas from oil wells, and gas well liquids unloading operations, all or some of which could apply to a well affected facility.

The definition of modification in the final rule is also very straightforward. Consistent with §60.14, a modification is when an existing well undergoes a physical or operational change results in increased emissions. The EPA believes that hydraulically fracturing or refracturing an existing well are the activities that result in an increase in emissions from a well, and thus these activities are specifically listed activities as modifications. The EPA agrees that a process change in other operations at the site do not constitute a modification of the well.

The EPA does not agree that wildcat and delineation wells should be categorically excluded from the well affected facility definition. However, the final rule does specifically exclude gas produced from wildcat and delineation wells from the definition of associated gas, effectively exempting them from the associated gas well requirements. The final rule also included separate provisions for wildcat and delineation well completions. The EPA does not expect wildcat and delineation wells to operate for an extended period which would require liquid unloading, so there are no special provisions under the liquids loading standards.

It is not appropriate to exempt wells from the NSPS if it is subject to state and local regulations. However, if the regulations include similar or more stringent requirements, the additional burden to comply with the NSPS should be minimal.

Comment: Commenter (2292-West Virginia Office of the Attorney General (WV AG) et al) suggests that the EPA is still defining “modification” in an exceptionally broad way. The commenter notes that breadth is particularly obvious when it comes to wells undergoing fracturing or refracturing, but the agency has also appeared to have left the door open for finding that liquids-unloading events could constitute “modifications,” too. 87 Fed. Reg. at 74,781-82. This redefinition, of course, would render the wells “new sources” subject to direct federal control. The commenter fails to see how these activities constitute “modifications” under either the CAA’s definition of the term or any ordinary understanding of it.

Response II-6-2: In the final rule the EPA has clarified that a liquids unloading event does not constitute a modification. This topic is discussed more in Section 6.4.1.2.

Comment: Commenter (2210- LANXESS Corporation) expresses concern that any well used to inject fluids could be interpreted as a “well affected facility” under 40 CFR 60.5365b regardless of source category. They point to the language indicating that a well affected facility, including a single well, where a “well” is defined in 40 CFR 63.5430b to mean “a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected” leading to this interpretation.

Response II-6-3: EPA has spelled out that the well affected facility applies to a single well “drilled for the purpose of producing oil or natural gas.” This makes it clear that wells into which fluids are injected are not well affected facilities.

Comment: Commenter (2218-Texas Commission on Environmental Quality (TCEQ)) requests that NSPS OOOOb include clear definitions for “oil well” and “gas well” to avoid ambiguity or confusion. States have different definitions of what is considered an oil well or a gas well. For example, the Texas Railroad Commission to Texas (RRC) defines cubic foot of gas, gas well, and oil well as follows:

“16 TAC [Texas Administrative Code] §3.79

(6) Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard

temperature base shall be 60 degrees Fahrenheit. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

(11) Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from a formation or producing horizon productive of gas only encountered in a wellbore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

(18) Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.”

Commenter (2218-TCEQ) states that the RRC currently monitors approximately 161,000 active oil wells and 87,000 active gas wells (as of December 2022). Without a clear definition of oil well or gas well, the commenter and RRC do not know which wells will be affected by the different requirements in NSPS OOOOb and emissions guidelines (EG) OOOOc (e.g., associated gas and liquids unloading requirements). Also, clarification is needed on the reference standard temperature and pressure in the definition of Gas to Oil Ratio in the proposed rule language.

Response II-6-4: EPA has chosen not to define oil wells or gas wells in NSPS OOOOb or EG OOOOc to avoid distinctions at the Federal level that are not the same across state programs.

## **6.2 Oil Wells with Associated Gas**

### ***6.2.1 Definition of Associated Gas***

Comment: Several commenters (2248-North Dakota Petroleum Council (NDPC), 2294-Ohio Oil & Gas Association (OOGA), 2326-American Exploration and Production Council (AXPC), 2360-Devon Energy, 2428-American Petroleum Institute (API) suggested that the EPA include a definition of “associated gas” and other related definitions in the proposed rules. Specific comments are provided in the following paragraphs.

Commenter (2248-NDPC) states that the EPA did not define “associated gas”. The commenter recommends that associated gas be defined as the gas that can be separated from the produced liquids in the first stage of separation at a pressure sufficient for it to flow into the gathering system.

Commenter (2360-Devon Energy) believes it is important for EPA and the regulated community to have a common understanding of the definition of associated gas. The commenter offers the following for consideration:

*Associated Gas* means the natural gas which originates at wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.

Commenter (2428-API) points out that the EPA did not include a definition of associated gas within 40 CFR 60.5430b or 40 CFR 60.5430c, which they do not believe was EPA’s intent. The commenter believes that the language EPA uses in the preamble when describing associated gas<sup>1</sup>, with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of new source performance standards (NSPS) OOOOb and emission guidelines (EG) OOOOc. The distinctions they provide in their suggest language explicitly determine which separator the requirements proposed in 40 CFR 60.5377b(a) would apply, providing clear transparency for the regulated community:<sup>2</sup>

*Associated gas* means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.

Commenter (2326-AXPC) notes that the December 2022 supplemental proposal would apply standards to oil wells with associated gas at well affected facilities (or well designated facilities under EG OOOOc) but does not define the terms “oil well” or “associated gas.”<sup>3</sup> Without definition, the commenter contends that the applicability of the proposed standards is unclear. To avoid confusion in implementation and enforcement, the commenter urges EPA to define these terms as proposed below.

The commenter (2326-AXPC) expresses that the term “oil well” is ambiguous and needs definition to avoid unintended applicability. While EPA proposes to define “well” as a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected,<sup>4</sup> it does not propose to define oil well or gas well separately. Absent a clear and objective definition, the “oil well” associated gas standards might be interpreted to apply to gas wells, which as noted in the preamble of the December 2022 supplemental proposal, is not EPA’s intent.<sup>5</sup> Oil and

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<sup>1</sup> 87 FR 74778.

<sup>2</sup> Without a clear definition, the commenter states that there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

<sup>3</sup> Proposed 40 CFR 60.5377b, .5391c.

<sup>4</sup> Proposed 40 CFR 60.5430b, .5430c.

<sup>5</sup> 87 Fed. Reg. at 74,778.



natural gas wells produce natural gas and hydrocarbon liquids, and these liquids are generally characterized as crude oil or condensate depending on the jurisdiction or context. Regulatory authorities often look to the produced gas to hydrocarbon liquids ratio to define whether a well is an oil well or a gas well but do so inconsistently. The commenter provides that the Bureau of Land Management (BLM), in its Waste Prevention, Production Subject to Royalties and Resource Conservation proposed rule (“Waste Prevention Proposed Rule”),<sup>6</sup> defined “gas well” as,

a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, exceeds the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio greater than 6,000 standard cubic feet (scf) of gas per barrel of oil is a gas well.<sup>7</sup>

The commenter (2326-AXPC) states that, like EPA’s proposals in NSPS OOOOb and EG OOOOc, BLM’s Waste Prevention Proposed Rule targets oil well associated gas flaring. The commenter proposes that EPA define oil well in the converse of how BLM proposes to define gas well, such that oil well is defined as:

a well for which the energy equivalent of the gas produced, including its entrained liquefiable hydrocarbons, is less than or equal to the energy equivalent of the oil produced. Unless more specific British thermal unit (Btu) values are available, a well with a gas-to-oil ratio less than or equal to 6,000 standard cubic feet (scf) of gas per barrel of oil is an oil well.

The commenter (2326-AXPC) believes this definition is objective and unambiguous and urges EPA to adopt this definition into the respective definitions of NSPS OOOOb and EG OOOOc. This definition is also consistent with how the U.S Energy Information Administration (EIA) defines oil well and gas well.<sup>8</sup> Further, the commenter concludes that using this definition will provide consistency across overlapping federal regulatory requirements and avoid conflicting regulatory requirements.

Commenter (2326-AXPC) adds that, without definition, the term “associated gas” could take on various meanings. The most literal interpretation could mean any gas associated with oil well production, which might include emissions from other NSPS OOOOb or EG OOOOc affected/designated facility types that EPA regulates in other sections of its proposal – e.g., collection of fugitive emissions components or storage vessels. EPA’s intent in the November 2021 proposed rule was to prioritize gas sales where a sales line is available, which suggests EPA’s intended target for these provisions is gas that could be routed to an available pipeline – i.e., produced gas generated in the first stage of separation. The commenter recommends that, to avoid ambiguity and potentially overlapping requirements under the proposed rule, EPA define “associated gas” consistent with this intent.

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<sup>6</sup> 87 Fed. Reg. 73,588, 73,616 (Nov. 30, 2022).

<sup>7</sup> Id. at 73,616.

<sup>8</sup> See US Energy Information Administration, [The Distribution of US Oil and Natural Gas Wells by Production Rate], 3 (Dec. 2022) (using 6,000 scf of gas per barrel of oil to distinguish oil wells from gas wells).

The commenter (2326-AXPC) explains that the ability for an operator to inject gas into a pipeline is a function of the pipeline operating pressure and the pressure of the gas source immediately upstream of the pipeline connection. If the gas source's pressure exceeds the pipeline pressure, the gas can enter the pipeline (assuming the gas composition meets required specifications for the pipeline), but if the source pressure is equal to or less than the pipeline pressure, the gas cannot flow into the pipeline. At most production facilities, a mixed stream of liquids and gas leaves the wellhead and goes to a separation vessel where gas is separated from the liquids and routed offsite. In some cases, operators use a portion of this gas for on-site operations. The gas evolved from liquids in this first stage of separation has the highest pressure, and operators inject this gas into a pipeline where available and feasible. Further, the volume of gas evolved in the first stage is typically of much greater volume than gas evolved in subsequent stages of separation, and the gas evolved in subsequent stages of separation is generally not of sufficient pressure for injection into a pipeline. For the lower-pressure gas evolved in subsequent separation, injection into a pipeline often requires compression, which is a significant cost and often requires use of a combustion engine. Given the lower volumes generated in subsequent separation stages, compression is often uneconomical and accompanied by potential environmental disbenefit where gas compression emissions outweigh the emissions reductions achieved by transporting the gas offsite by pipeline as opposed to controlling it onsite. The environmental disbenefits become more pronounced as a well's production levels decrease over time. This is because the compressor's operation and associated emissions will remain relatively static over time, but the total gas evolved will decrease over time, meaning a similar amount of compression emissions will occur to achieve increasingly fewer emissions reductions over the life of the well.

Given EPA's intent to prioritize gas sales and, with respect to the gas evolved in later stages of production, the physical constraints and potential environmental disbenefits, the commenter (2326-AXPC, 3818-AXPC) proposes that EPA define "associated gas" as

the natural gas evolved from hydrocarbon liquids during the initial stage of separation following production from the wellhead. Associated gas does not include natural gas associated with well completion or downhole well maintenance activities.

Commenter (2294-OOGA) suggests that the definition of "associated gas" be limited to gas generated in the first stage of separation.

Response II-6-5: EPA agrees with the commenters that a definition of associated gas will facilitate understanding of the affected sources and the requirements related to managing associated gas. EPA included a definition of "associated gas" within the definitions section of this final rule and emissions guidelines. See 40 CFR 60.5430b and 40 CFR 60.5430c. The EPA has chosen not to define oil wells or gas wells in NSPS OOOOb or EG OOOOc to avoid distinctions at the Federal level that are not the same across state programs.

## 6.2.2 Proposed BSER – NSPS OOOOb

[**Note:** Most of the comments provided on the proposed BSER apply to both the NSPS OOOOb and EG OOOOc. For comments that specifically refer to EG OOOOc proposed applicability and BSER, see section 6.2.4 of this Chapter.]

### 6.2.2.1 Recovery of Associated Gas

Comment: Commenter (2433-Environmental Defense Fund (EDF) et al) suggests that EPA define best system of emission reduction (BSER) as associated gas recovery with allowances for specific circumstances of temporary flaring and venting. The commenter provides that the EPA’s current proposal permits using one of four gas recovery options to comply with its standard for associated gas at oil wells and includes a technical infeasibility exemption from the standard. The commenter recommends that EPA define the BSER as recovery of associated gas to (1) route into a gas gathering flow line or collection system to a sales line, (2) use as an onsite fuel source, (3) use for another useful purpose that a purchased fuel or raw material would serve, or (4) reinject into the well or inject into another well; unless one of a set of clearly defined circumstances exist where temporary flaring or venting would be applied.

The commenter (2433-EDF et al) states that the term “standard of performance” means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which the Administrator determines has been adequately demonstrated.<sup>9</sup> In designating the BSER, EPA must first identify the various “systems of emission reduction” that have been “adequately demonstrated” for a given source category.<sup>10</sup> Of those systems, it must then select the “best,” taking into account the “extent of emission reduction” achieved by the system,” “costs,” “nonair quality health and environmental impacts,” “energy requirements,” and “technological innovation.”<sup>11</sup> EPA must set the standard at a level that is “achievable”<sup>12</sup> but reflects the “maximum practicable degree” of “control[.]”<sup>13</sup> Indeed, the commenter provides that the Clean Air Act (CAA) “requires that the standards [] maximize the potential for long term economic growth ‘by reducing emissions as much as practicable.’”<sup>14</sup> The commenter adds that Courts will generally uphold EPA’s designation of the BSER so long as it is not “exorbitantly costly in an economic or environmental way”<sup>15</sup> or “unreasonable.”<sup>16</sup>

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<sup>9</sup> 42 U.S.C.S. § 7411.

<sup>10</sup> See, e.g., 83 Fed. Reg. at 65433–34 (expounding upon 42 U.S.C. § 7411(a)(1) and citing relevant cases, including *Sierra Club v. Costle*, 657 F.2d 298, 326, 343, 346–47 (D.C. Cir. 1981); *Lignite Energy Council v. EPA*, 198 F. 3d 930, 933 (D.C. Cir. 1999); *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); and *Portland Cement Ass’n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975)).

<sup>11</sup> 83 Fed. Reg. at 65433–34.

<sup>12</sup> *Id.*

<sup>13</sup> 116 Cong. Rec. at 42,385 (1970).

<sup>14</sup> *Costle*, 657 F.2d at 326.

<sup>15</sup> *Essex Chemical Corp.*, 486 F.2d at 433.

<sup>16</sup> *Costle*, 657 F.2d at 343.

Commenter (2433-EDF et al) points out that there are a variety of “systems” to reduce emissions from associated gas at oil wells that EPA has assessed, including the system set forth in its November 2021 proposal that would have allowed flaring at a 95 percent combustion efficiency rate if access to a sales line was not available. The commenter notes that other potential systems include those implemented by states such as Colorado and New Mexico.

Commenter (2433-EDF et al) states that of these systems, the “best” that has been “adequately demonstrated” after considering the “extent of emission reductions,” “costs” and “technological innovation,” among other factors, are those being implemented in Colorado and New Mexico. The commenter contends that these regulatory frameworks prohibit the routine flaring of associated gas and restrict flaring and venting to a set list of circumstances. As in EPA’s supplemental proposal, Colorado and New Mexico require operators to capture associated gas from oil wells and either route the gas to a sales line or put it to an alternative use. The alternative uses allowed in New Mexico largely overlap with those included in EPA’s supplemental proposal and include, among other things, power generation on lease, liquids removal on lease, reinjection for underground storage, and other alternative uses approved by the division.<sup>17</sup> For wells that are not connected to a pipeline, Colorado similarly allows operators flexibility to use other options to capture gas including to generate electricity or to process the gas to recover natural gas liquids, without venting or flaring.<sup>18</sup>

Commenter (2433-EDF et al) states that a standard based on approaches like those adopted in Colorado and New Mexico, which clearly limits and delineates circumstances where temporary flaring would be permitted, represents the “best system” for several reasons. For one, it would require gas recovery but contain reasonable exemptions for temporary flaring during certain activities that may require flexibility to vent or flare. Thus, this system would “reduc[e] emissions as much as *practicable*”<sup>19</sup> and reflect the “maximum *practicable* degree of control.”<sup>20</sup> The standard would permit technological flexibility by allowing the use of a multitude of abatement methods, including routing to a sales line, injection, or reinjection, use as onsite fuel, or use for another alternative purpose. And, as EPA notes in its supplemental proposal, technological innovation could potentially bring to the forefront more abatement methods that are not currently identified. Finally, the costs of a capture standard, as discussed above, are reasonable,<sup>21</sup> cost-effective, and in some instances are even profitable for operators.

Finally, commenter (2433-EDF et al) states that a system requiring capture using different technologies with allowances for temporary flaring or venting under certain circumstances has been “adequately demonstrated.” The commenter notes that Colorado, for example, passed its regulations after a lengthy stakeholder and rulemaking process. Numerous operators, including the largest producers in the Denver-Julesburg Basin – PDC Energy Inc. and Occidental Petroleum Corporation – participated in the rulemaking, as did the Colorado Oil and Gas Association, the Small Operator Society, and the American Petroleum Institute (API). The three largest producers in the Denver-Julesburg Basin expressed “general support” for the Colorado

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<sup>17</sup> N.M. Code R. § 19.15.27.9.D.(5) (2023).

<sup>18</sup> 2 Colo. Code Regs. § 404-1-903.d.(3).(E).

<sup>19</sup> See *Costle*, 657 F.2d at 326 (emphasis added).

<sup>20</sup> See 116 Cong. Rec. at 42,385 (1970) (emphasis added).

<sup>21</sup> See *Costle*, 657 F.2d at 343.

Oil and Gas Conservation Commission (COGCC) proposed rules and several noted that they shut in production facilities rather than flare or vent during instances of reduced gathering line pressure or limited takeaway capacity.<sup>22</sup> According to the commenter, none of these producers objected to the rule's prohibition on routine flaring or venting. Rather, their comments were limited to ensuring that the COGCC rules did not prohibit flaring or venting allowed by the Air Pollution Control Division (APCD).<sup>23</sup> And no party challenged the adoption of the rules once promulgated.

Further, to date, commenter (2433-EDF et al) states that the COGCC has granted only one variance from the prohibition on routine venting and flaring contained in R.903.(d)(3).<sup>24</sup> Similarly, the commenter provides that New Mexico's standards were developed during a lengthy stakeholder and rulemaking process that included input from the New Mexico Oil and Gas Association and OXY USA, and no party challenged the adoption of the rules once promulgated. Operator support for a standard that requires capture with narrow exemptions, the absence of challenges to the rules, and the minimal variances that have been granted in Colorado are evidence of the reasonableness of these measures. Operator practice also has shown such a standard is adequately demonstrated. Exxon, for example, has halted all routine flaring in the Permian Basin.<sup>25</sup> The Rystad report notes that most operators in Texas, North Dakota, New Mexico, Wyoming, and Colorado report low flaring volumes.<sup>26</sup> The commenter provides that those operators that have reduced flaring have done so through "a change in mindset from viewing flaring as a part of normal operations to viewing flaring as a constraint on operations."<sup>27</sup>

Because a standard that requires capture with a narrow set of exemptions is cost-effective, would reduce emissions to the greatest extent practicable, and has been adequately demonstrated, the commenter (2433-EDF et al) recommends that the EPA consider it to be the BSER.

Response II-6-6: EPA agrees in part with the commenter. In this final rule EPA has defined the best system of emission reduction (BSER) for new sources as associated gas recovery with limited allowances for specific circumstances of temporary flaring and venting. EPA has

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<sup>22</sup> Response of PDC Energy, Inc. to 900-Series Prehearing Statements, at p. 2, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), <https://drive.google.com/drive/u/0/folders/1VOozq1I7HYNRsH52mS3oyyoPbIumdZb2>; Response of Occidental Petroleum Corporation to 900-Series Prehearing Statements, at p. 2, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), <https://drive.google.com/drive/u/0/folders/1hwQ9s9rkyL8V9HXvZn7GbnwhqKJ5N6>; Response of Noble Energy, Inc. to 900-Series Prehearing Statements, at p. 1, In the Matter of the Changes to the Rules and Regulations of the Oil & Gas Conservation Commission of the State of Colorado, Docket No. 200300071 (2020), <https://drive.google.com/drive/u/0/folders/1hA1n8n0zvLSE0U-UPED20pVQz-KJeRCf>.

<sup>23</sup> Response of Noble Energy, Inc. to 900-Series Prehearing Statements, *supra* note 429, at 3; Response of PDC Energy, Inc. to 900-Series Prehearing Statements, *supra* note 429, at 1.

<sup>24</sup> Colo. Oil & Gas Conservation Comm. (COGCC) Order, Williford Resources, LLC, Docket No. 210100008 (Apr. 20, 2022) (Attachment U).

<sup>25</sup> Sabrina Valle, Exclusive: Exxon halts routine gas flaring in the Permian, wants others to follow (Jan. 24, 2023), <https://www.reuters.com/business/energy/exxon-halts-routine-gas-flaring-permian-wants-others-follow-2023-01-24/>.

<sup>26</sup> Rystad, *supra* note 394, at 100.

<sup>27</sup> *Id.* at 80.

finalized a standard for new sources that will mostly require routing of associated gas to a sales line, or an alternative that achieves equivalent emissions reductions. As explained in sections X.F.2. and XI.F.2. of the final rule preamble, the standards for new sources do include limited circumstances that could result in flaring. For the reasons explained there, EPA still finds that these are necessary to include. For all modified and some existing sources, EPA is finalizing our proposal that could allow for routine flaring, but only in limited circumstances after a demonstration that the discussed zero emissions options are technically infeasible. For the reasons explained in Sections X.F.2. and XI.F.2. of the final rule preamble, EPA finds this appropriate. Lastly, in the context of existing sources, EPA's final EG OOOOc includes a subcategory for sources that produce less than 40 tpy methane of associated gas. The presumptive standard for the subcategory allows routine flaring without a showing of technical infeasibility because EPA's analysis conducted after reviewing comments on the supplemental proposal indicated that it is not reasonable with respect to cost to require these sources to route their associated gas to a sales line. See Sections X.F.2. and XI.F.2. of the final rule preamble for further explanation of this subcategory.

Comment: Commenter (2433-EDF et al) suggests that the BSER for associated gas should include routing to a sales line and gas recovery for other uses. They note that previous comments they provided for the 2021 proposal recommended EPA eliminate the harmful, polluting, and wasteful practice of routine flaring by determining that the "BSER for emissions from associated gas is to capture and sell, productively use or reinject the gas."<sup>28</sup> The commenter further advocates for EPA to require operators to "capture and route emissions to a sales line, to use it on-site for a productive purpose, or to preserve it through re-injection" and "carefully delineate when exemptions may apply."<sup>29</sup>

Commenter (2433-EDF et al) states that in both the November 2021 proposal and the December 2022 supplemental proposal, EPA determined the BSER for associated gas to be routing to a sales line.<sup>30</sup> However, in the December 2022 supplemental proposal, EPA agreed that alternative uses of the associated gas should be allowed, "as these options are equivalent in terms of emission reduction to the identified BSER." The commenter recommends that EPA clarify that the BSER for associated gas includes routing to a sales line and other gas recovery options. Specifically, the commenter recommends that EPA state that BSER includes the following four gas recovery options:

- Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line,
- Recover the associated gas from the separator and use the recovered gas as an onsite fuel source,
- Recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, or

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<sup>28</sup> 2022 Joint Environmental Comments, *supra* note 1, at 178.

<sup>29</sup> *Id.* at 181.

<sup>30</sup> 86 Fed. Reg. 63110, 63237–38.

- Recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well.

For the second option encompassing “onsite use,” the commenter (2433-EDF et al) urges EPA to clarify that the onsite use must be one associated with oil and gas production. This is to ensure that the use is one EPA is familiar with and has authority to regulate so that unintended venting does not occur from unpermitted or uncontrolled sources. One example where this can occur cited by the commenter is cryptocurrency mining operations.

For the third option encompassing use for “another useful purpose,” commenter (2433-EDF et al) supports EPA’s interpretation encompassing emerging techniques that provide for an alternative use offsite, such as compressing gas and transporting it to a pipeline or processing plant. However, the commenter urges EPA to clarify that the use of associated gas for cryptocurrency mining operations does not qualify as a legitimate alternative use.

For the fourth option of reinjection/injection, commenter (2433-EDF et al) recommends that EPA remove any specific reference to “enhanced oil recovery.” The commenter explains that other preferable options exist for injected or reinjected gas, such as permanent storage in porous geological formations, and there is no reason to disallow or subordinate these alternatives. The commenter cites the Rystad report (included as Attachment W to their November 2021 proposal comments) demonstrates that storage is available in all the states primarily responsible for associated gas flaring, except for North Dakota. Notably, they report that saline aquifers are an alternative potential for storage in North Dakota.<sup>31</sup>

Commenter (2433-EDF et al) states that their November 2021 proposal comments provided detailed information regarding the cost-effectiveness and availability of these alternative options.<sup>32</sup> As stated in their prior comments, they believe “at least one or more of the best practices [including the compliance alternatives EPA proposes here] for gas capture and sale, productive use, or reinjection. . . are broadly available to operators at a reasonable cost in every basin and at every production level.”<sup>33</sup> Further comments provided on costs for these option are included in section 6.2.2.5 of this Chapter.

Response II-6-7: EPA believes that our final regulatory text largely captures the suggestions by the commenter with respect to requiring routing to a sales line, and offering non-flaring alternatives that achieve equivalent emission reductions. See 60.5377b for the final regulatory language.

EPA declines to modify “another useful purpose” in the way suggested by the commenter. EPA finds the suggestion to restrict the use to “be one associated with oil and gas production” to be overly prescriptive. EPA cannot predict the of ways that methane could be used to create other chemical feedstocks, or be used in the production of energy. EPA does not want to restrict the

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<sup>31</sup> Rystad Energy, Cost of Flaring Abatement, at slide 67 (Jan. 31, 2022) [Hereinafter Rystad] (included in 2022 Joint Environmental Comments, supra note 1, as Attachment X.

<sup>32</sup> 2022 Joint Environmental Comments, supra note 1, at 185–89.

<sup>33</sup> Id. at 190.

future possibility of a useful alternative to flaring if that alternative achieves equivalent reductions.

EPA agrees that using the gas for another useful purpose is supported by the avoidance of emissions from flaring.

EPA agrees that reinjection should be an alternative to flaring, regardless of whether the recipient well is for enhanced oil recovery, because it is equivalent to routing to a sales line for methane reduction. As such, EPA has revised the option in the regulatory text.

With respect to cost-effectiveness data submitted by the commenter, EPA determined that the basis for these cost estimates lacked some details that EPA thought necessary to use them as the basis for a BSER analysis and they were not used in the BSER analysis. Please see Response II-6-19 of this Chapter and the TSD in the docket for more information.

Comment: Commenter (2301-U.S. Chamber of Commerce (USCC)) supports EPA's conclusion that "beneficial uses of the associated gas"—such as on-site use or reinjection into another well for enhanced oil recovery—should be deemed "equivalent" to the identified BSER of routing the gas to a sales line. For similar reasons, the commenter recommends that EPA allow a broad range of on-site beneficial purposes, without being prescriptive, to provide sufficient regulatory flexibility for future innovation.

Response II-6-8: EPA agrees with the commenter that options for beneficial use of the gas should be relatively unrestricted. EPA cannot predict the number of ways that methane could be used to create other chemical feedstocks, or be used in the production of energy available to the grid. EPA does not want to restrict the future possibility of a useful alternative to flaring when if that alternative achieves equivalent reductions.

Comment: Commenter (2315-New York State Department of Environmental Conservation (NYSDEC)) notes that the EPA requested comment on whether the proposed requirements will incentivize the sale or productive use of captured gas, and if not, inquired whether there are other methods that the EPA could use to incentivize or require the sale or productive use instead of flaring. In response, the commenter states that they support the creation of incentives or requirements to capture and use captured gas. The challenge is to understand, with relative certainty, what is being emitted prior to capture. The commenter recommends that EPA gather meaningful data about the emission sources prior to offering incentives.

Additionally, the commenter (2315-NYSDEC) states that they understand this solicitation to mean the proposal is attempting to regulate wells on private property or on lands currently regulated by the states. The commenter believes that a one-size-fits-all approach to regulating these wells will not result in more effective regulation because the conditions, construction, age, and other variables differ depending on the state and formation. They conclude by stating that these differences necessitate different approaches to regulating wells.

Response II-6-9: EPA agrees with the commenter that options to manage associated gas will not be universal. Recognizing this, EPA has developed a variety of approaches to new , modified,



and existing sources. See Response I-6-3 in this Chapter and Sections X.F.2. and XI.F.2. of the final rule preamble for EPA's full discussion of these different standards and the reasoning for each.

#### 6.2.2.2 Opposition to Elimination of the Option to Flare Associated Gas

Comment: Commenter (2428-API) recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. However, the commenter disagrees with EPA's approach to the control standards proposed including the level of recordkeeping and reporting as they believe it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis<sup>34</sup> of the impact of the rule on potential production conducted by the commenter indicates that if the final rule were to eliminate flaring of associated gas or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. The commenter asserts that they could not support such a restriction or implementation. Should the final rule either expressly or practically eliminate flaring of associated gas, the commenter states it could be technically infeasible and not cost effective.

Commenter (2428-API) states that the provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure. Specifically, the notion that "recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line" constitutes a control option as proposed under 40 CFR 60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in 40 CFR 60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states "In addition...a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions." The commenter agrees that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in 40 CFR 60.5377b(a) do not adequately address associated gas that is typically recovered.

Commenter (2428-API) continues to support EPA's description of the proposed requirements for associated gas from oil wells in the November 2021 preamble description, but the commenter does not support the hierarchy of the compliance options and associated recordkeeping and

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<sup>34</sup> The commenter contends that the EPA did not provide sufficient time to fully analyze the December 2022 supplemental proposal and its potential impacts as EPA did not grant their request for an extension of the comment period. The commenter notes that they will continue to evaluate the potential impacts of the December 2022 supplemental proposal.

reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, the commenter supports:

- Recovering gas to sales in 40 CFR 60.5377b(a)(1).
- The beneficial use of the associated as onsite fuel proposed in 40 CFR 60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in 40 CFR 60.5377b(a)(4).
- Flaring the gas such that 95 percent control efficiency is achieved as proposed in 40 CFR 60.5377b(b).
- An annual reporting requirement focused on periods of venting.

One commenter (2248-NDPC) provides that approximately 99 percent of the gas that is intended to be sold in North Dakota is already connected to a gathering system. Five percent of that was flared due to pipeline issues. The commenter reports that there are many reasons why gas is preferentially flared over putting it into a gathering system. Some scenarios provided by the commenter are:

- A well could produce natural gas that contains hydrocarbon compounds that are not compatible with the nearby infrastructure (e.g., hydrogen sulfide (H<sub>2</sub>S), carbon dioxide (CO<sub>2</sub>), nitrogen (N), etc.). This is commonly called off-specification gas. Pipelines need to be made from materials that are compatible with the gas and additional equipment will need to be designed and constructed at the regional gas processing plant to be able to take the gas and process it to a pipeline quality specification.
- A well could turn sour over time (i.e., the Hydrogen sulfide in the gas will increase to levels that make it off specification and not saleable).
- Gathering systems and natural gas processing plants are often owned and operated by different companies (midstream). Extreme weather, electric power disruption, and accidents such as fire are just a few examples of force majeure where a midstream company temporarily or permanently shut in the gathering system and prevents the gas from being sold.
- Over time, that well pressure will drop. If it drops below the gathering line pressure, the associated gas will not flow into the gathering system.
- The third-party gatherer may take the system down for maintenance or repair.
- In North Dakota, our associated gas is considered “wet gas”. Wet gas contains a significant proportion of hydrocarbon compounds heavier than methane (e.g., ethane, propane, and butane). These compounds can be gaseous or liquid and gaseous in the reservoir. When wet gas is brought to the surface, these heavier hydrocarbons can condense out of the gas. This is especially true in winter months when the ground temperature is cooler. When these hydrocarbons condense out of the gas in the pipeline, the liquid hydrocarbons can collect in low spots in the pipeline, which reduces the effective diameter of the pipeline and results in a hydraulic constraint or reduce gas flow. Sending a pig down the pipeline is necessary to remove the liquids and hydraulic constraints.

Response II-6-10: EPA agrees with the commenter that the complete elimination of flaring of associated gas in all situations is not practical, for safety and other reasons. EPA therefore has

designed our final rule to prohibit long term flaring for some sources, while leaving options open to other sources to manage associated gas in ways that makes flaring less frequent. See Sections X.F.2 and XI.F.2 of the final rule preamble for discussion of the final standards for OOOOb as well as the final presumptive standards for OOOOc. In the context of existing sources of associated gas, EPA included a subcategory in the final emission guidelines for sources that produce 40 tpy or less of methane that allows those sources to flare routinely. In accordance with the final EG, existing sources that produce over 40 tpy of methane could also flare provided other options are technically infeasible. See 60.5377c for model rule text in OOOOc on this point. As alluded to above, EPA's final standards also allow for flaring where circumstances are not routine and flaring is the reasonable option for interim periods such as malfunctions or interruptions in sales line service. See section 60.5377b and 60.5377c for specific regulatory language described here. EPA believes that these various allowances for flaring address the bulk of commenters concerns. The finalized standards are not an absolute prohibition on flaring. EPA further points out that the standards in OOOOb will apply to certain new wells, such that only those new wells will be subject to standards that do not allow routine flaring. Wells where the gas is typically being captured to a sales line already would be considered existing wells that would not be subject until the state designates those as affected sources. Upon being designated facilities under OOOOc EG, EPA does not see a problem to continue routing to a sales line, and does not agree there is a recordkeeping burden for sources already meeting BSER. For those designated facilities that would find it to their advantage to use another option to BSER, there is likewise little significant burden in recordkeeping or reporting. The only instance of additional significant recordkeeping and reporting would be for those wells that produce more than 40 tpy methane but for which there is no feasible alternative to flaring. Given the substantive comments we received supporting our approach, we do not think there will be an overwhelming number of such cases, or that the due diligence burden of developing a record and submitting a demonstration of infeasibility is unreasonable.

As stated in the previous paragraph, EPA's final standards allow for flaring where circumstances are not routine and flaring is the reasonable option for interim periods such as malfunctions or interruptions in sales line service. One such provision is during those periods when the well produces off-specification gas. The souring of gas over time, or pressure drop of the gas going to the gathering system, could make the gas unsuitable for sales, and the operator would have to seek another non-flaring alternative for the gas, unless the overall production of the gas is below 40 tpy methane. Temporary interruptions in gas gathering for the reasons cited by the commenter are contemplated in the temporary provisions for an interruption in service which allow flaring of limited duration. Pigging operations are an issue related to maintenance of pipelines and are not directly related to associated gas from a separator at a well site.

Comment: Commenters (2168-Indiana Oil and Gas Association (INOGA), 2172-Kentucky Oil and Gas Association (KOGA)) believe that EPA needs to maintain flaring as an option. Many of the commenters' members produce oil with little associated gas. The gas production rate is too low to be able to justify the expense of routing to a sales line or even investing in the equipment to inject the gas back into the reservoir. Many times, the gas production rate is too low to be able to reliably operate an engine to produce power to operate surface equipment. They add that low production wells need to have the option to flare the gas as an environmentally acceptable

option. The commenters believe that eliminating this option would be an unnecessary burden on small businesses.

Commenters (2168-INOGA, 2172-KOGA) express that they understand EPA's perspective that gas should be sold or utilized when it is produced in a large enough volume to justify the expense, or the production is high enough to reliably operate surface equipment. They report that some of the commenters' members sell gas into the national gas market. Data that the commenters have gathered shows that the cost of connecting to a major gas transportation pipeline can cost tens of thousands of dollars, to hundreds of thousands of dollars. According to the commenters, the cost just to make the connection to the gas line for sales is more than the value of the gas that could be sold into the gas market. In addition, the cost to make the gas pipeline quality usually exceeds the value of the gas that might be sold into the gas market.

Commenters (2168-INOGA, 2172-KOGA) ask if industry and EPA work together to create a low complexity structure to be able to achieve EPA's goals of utilizing most of the gas without eliminating the option when no other option exists? Several of the commenters' members have expressed concern that the cost and experience needed to operate a combustion system is beyond their capability. The commenters report that many of the commenters' members do not have the expertise to be able to operate a combustion system safely and efficiently. They provide that operating a flare is a low cost, low technology method to efficiently eliminate gas that might otherwise be vented to the atmosphere.

Response II-6-11: See Response II-6-6 of this Chapter.

#### 6.2.2.3 Wildcat or Delineation Oil Wells

Comment: Commenter (2428-API) notes that, in their January 31, 2022, comment letter, they asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, the commenter explains that these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. The commenter states that the EPA has acknowledged this fact within the definitions that have been published in 40 CFR 60.5430a and maintained in the proposed 40 CFR 60.5430b and 60.5430c where the terms are defined as:

*Wildcat well* means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

*Delineation well* means a well drilled in order to determine the boundary of a field or producing reservoir.

In response to their January 31, 2022, comment letter, the commenter (2428-API) provides that the EPA stated (see 87 FR 74780):

The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for

these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also what methods are currently in use, or could be used, to minimize methane and [volatile organic compound] VOC emissions in these situations.

Like provisions within NSPS OOOOa for well completions, the commenter (2428-API) recommends that the EPA allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.<sup>35</sup> These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, the commenter (2428-API) states that, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat/delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. The commenter explains that there will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in 40 CFR 60.5377b(a) or 40 CFR 60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

According to the commenter (2428-API), since wildcat or delineation wells will typically cease production in well under 180 days<sup>36</sup>, a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce volatile organic compound (VOC) and methane emissions. The commenter therefore requests EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion

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<sup>35</sup> EPA determined well testing “conducted immediately after well completion, is considered part of the well completion” for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in 40 CFR 98.238).

<sup>36</sup> The commenter notes the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, they add that the duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g., BLM’s NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the commenter recommends that the control device compliance requirements mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

The commenter (2428-API) suggests that the EPA add the following within 40 CFR 60.5377b:

For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

Commenter (2326-AXPC) suggests that EPA should allow operators to control associated gas from wildcat or delineation oil wells without justification of technical infeasibility or safety reasons. The commenter supports the American Petroleum Institute (API) suggested redline and supporting comments that would allow operators to utilize a temporary or portable combustion device similar to those used to control emissions from well completions to reduce VOC and methane emissions from wildcat or delineation oil well associated gas without justifying that sale, beneficial use, or reinjection is technically infeasible or unsafe.<sup>37</sup> As noted by API, these wells typically cease production within 180 days and are typically remotely located significant distances from natural gas pipelines. The commenter suggests including the following in 40 CFR 60.5377b and 60.5391c:

For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

Response II-6-12: EPA has defined associated gas to exclude gas from exploratory and wildcat wells, if and until those wells become producing oil wells with associated gas. See the definition of associated gas in 60.5430b.

Comment: Commenter (2227-WEA) states that wildcat and delineation wells, and oil wells located on sites with no natural gas takeaway infrastructure (pipeline) should be categorically excluded from requirements to recover natural gas. Associated gas from such wells may be captured for beneficial use (e.g., fuel), routed to a flare or otherwise combusted. Furthermore, a demonstration that it is not feasible to recover natural gas from oil wells with no pipeline

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<sup>37</sup> See API Supplemental Proposal Comments § 4.5.

takeaway capacity for technical or safety reasons is an unnecessary burden and should not be required.

Response II-6-13: See Response II-6-12 of this Chapter.

Comment: Commenter (2248-NDPC) expressed that, in NSPS OOOOa, wildcat and boundary wells were exempt from the Reduced Emission Completion (REC) standards. The commenter suggests the EPA extend this exemption to the associated gas standard. The exploration of oil and natural gas begins in areas before the infrastructure can be designed, sized, and constructed. It's only after a field is proven, through the drilling of wells, that the quantity, quality, and economics of the oil and natural gas can be determined. For example, the commenter states that a company could drill a dry hole, and any money spent on the gathering system would be wasted.

Response II-6-14: See Response II-6-12 of this Chapter.

#### 6.2.2.4 Low Production Wells

Comment: Commenter (2172-KOGA) recommends that EPA maintain an exemption for low production wells. The commenter explains that many of the low production wells operate with low pressure and low gas to oil ratios, so the Potential to Emit (PTE) is significantly less than the PTE for higher production wells that were recently drilled. Illinois Basin crudes are typically undersaturated with associated gas. The initial gas to oil ratios is typically in the 300-400 cubic feet/ barrel of crude oil (bbl) range, while greater than 1,000 cubic feet/bbl in other basins. In older Illinois Basin waterfloods the gas to oil ratios is too low to reliably operate a separator. For example, an operator made a discovery in 1974 that produced 10 cubic feet per bbl upon initial production. This well is still producing with virtually no associated gas produced. According to the commenter, requiring additional regulations on this type of low production well is not cost effective and does not provide meaningful environmental benefits.

Response II-6-15: See Response II-6-6 of this Chapter where EPA describes the subcategory created for existing wells that produce up to 40 tpy methane.

Comment: Commenter (2294-OOGA) states that one of the critical flaws of the NSPS OOOO regulations, including NSPS OOOOb and EG OOOOc under the supplemental proposal, is the failure to properly account for the declining production of oil and natural gas from a well over time, and the corresponding decline in emissions in connection with various operational changes at the well site associated with the decline in production. While initial production at a well may be significant, it will deplete as the well ages and eventually become a low production well. According to the commenter, the failure to properly account for this change skews the fundamental basis of the entire NSPS OOOO program – i.e., the cost-effectiveness analysis for establishing the BSER for each source that is subject to the program. The commenter asserts that the magnitude of this fundamental flaw is most significant in the resulting EG OOOOc for existing sources, which have a disproportionate and detrimental impact on low production wells and small businesses.

Commenter (2294-OOGA) points out that a significant portion of the approximately 62,000 wells in Ohio meet the definition of a low production well (i.e., produce at or below 15 barrels of oil equivalent per day) and, in fact, produce far less. About 60 percent of the wells in Ohio involve private contractual relationships between the producer and landowner to take a limited amount of natural gas for the lessor's private domestic use. The commenter adds that this means that there are approximately 36,700 rural Ohio families who have direct access to natural gas because of operating oil and gas wells. Many of these wells are owned by a landowner or a small business. The commenter contends that the December 2022 supplemental proposal is replete with stringent emissions standards and related compliance requirements that are impractical, technically infeasible, cost-prohibitive, overly burdensome, and otherwise unreasonable. They state that the impacts of such requirements are disproportionately borne by small businesses and operators of low production wells.

Response II-6-16: EPA set BSER for new wells and set a different BSER for modified and designated wells. EPA set another BSER for designated wells that must manage 40 tpy or less of methane. EPA set this array of standards to reflect the determination, in general agreement with the commenter, that BSER would be different for wells across the category.

EPA is aware that over time well production will decline, and the associated level of associated gas may diminish over time as well. The standards do not prohibit that a source choose a different option over time if making a change from routing to a sales line to an alternative is in the interest of the source. EPA chose to set BSER for modified wells as routing to a sales line, but ultimately allowing the source to flare if other options were infeasible, as a reflection of the options that a modified well should have to manage associated gas.

#### 6.2.2.5 Cost/Benefit Analysis

Comment: Commenter (2428-API) states that based on their preliminary review of EPA's Supplemental Technical Support Document (TSD), the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements. They provide the following comments on the model plant analysis:

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.
- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.
- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. They note that they provided these costs to the EPA in previous comments they submitted, and they note that they estimated certifications to costs to be \$2,000 - \$9,000. Commenter (2428-API) notes in the commenter's January 31, 2022, letter, they stated:

“a more representative cost for installing a flare suitable to control associated gas would



be \$100,579, based on the average costs EPA uses for analyzing storage vessel controls.”.[1] We also stated, “that we did not include the costs from EPA’s Workbook ‘MP1 Plus Monitors.xlsx’ as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA’s cost analysis.

Commenter (2428-API) states in the December 2022 supplemental proposal, EPA has proposed additional parametric monitoring but has not included these costs in the analysis.”

Response II-6-17: As the commenter points out, the EPA did not perform a detailed cost analysis for routing associated gas to a sales line. EPA has corrected this by performing a detailed cost analysis of routing to a sales line to set BSER. EPA set BSER for associated gas as routing to a sales line as the most effective means of reducing emissions at a reasonable cost. EPA also recognizes that routing to a sales line may not be a feasible or the most cost-effective option for every well with associated gas, and therefore provided for alternatives that achieved equivalent reductions. EPA did not base the BSER determination on the cost of flaring associated gas. See the TSD in the docket detailing EPA’s analysis of the cost of routing to sales. EPA has revised certain requirements for flaring operations. To respond to the comment regarding monitoring of existing affected sources and their control devices, see section X.H. and XI.H. for the reasons that EPA has increased monitoring requirements for combustion control devices to assure operators and regulators that controls operate at prescribed destruction efficiency.

As the commenter points out the EPA did not develop full cost analyses of the alternatives to BSER such as injection of the gas into the well or another well, using the gas as fuel, or converting the gas to CNG or LNG to be transported off-site, or another useful purpose. The EPA did not perform detailed cost analyses of those options because the standards do not require sources to adopt them. Sources may adopt them as acceptable alternatives to BSER when it is in the better interest of the source to do so. EPA did this in recognition that many of these techniques are already in use, that across the category not every well with associated gas can be regulated with one-size-fits-all BSER, and in those cases where connecting to a sales line is at the higher end of the cost spectrum, one of the alternatives is likely to be less costly than BSER. We received comments exactly to this effect.<sup>38</sup> While it is true that the analysis supporting a certification of infeasibility may cost in the range cited by the commenter, we have revised the requirement by not requiring that a licensed engineer perform and certify the analysis, but rather are allowing personnel with appropriate expertise to conduct the analysis.

Comment: Commenter (2446-Independent Petroleum Association of America (IPAA)) states that most of the studies used by EPA in the past and used to support these proposals are based on data predominantly taken prior to 2015 which means that it predates the NSPS OOOOa regulations and was at the beginning of the implementation of the NSPS OOOO regulations. The commenter reports that they have submitted information on this issue in prior comments demonstrating that the turnover in wells means that most of the existing source pool that exceeds 15 barrel of oil

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<sup>38</sup> Rystad, *supra* note 394, at 11.

equivalent (boe)/day will be from NSPS OOOO and NSPS OOOOa well sites. The commenter states that the brunt of the impact of the EG will fall on low production wells. They state that, by the proposal using the November 2021 effective date, this creates the anomalous issue of requiring sources complying with prior NSPS requirements to replace equipment and processes at considerable expense to owners/operators under the EG. The commenter notes that the EPA has not evaluated the impact on the original BSER/cost-effectiveness evaluation and justification for various requirements under previously enacted NSPS for the Oil and Gas Industry.

Response II-6-18: EPA disagrees that EPA's proposed standards for associated gas are based exclusively on data from 2015. EPA developed the cost analysis based on industry data from 2014, 2015, and 2018 and was supplemented by data provided by industry after the supplemental proposal<sup>39</sup>.

EPA agrees in part with the commenter regarding certain wells that produce low levels of associated gas. As explained in sections X.F.2. and XI.F.2. of the final rule preamble, EPA has included a subcategory in the final EG for wells that produce less than 40 tpy methane of associated gas.

Comment: Commenter (2433-EDF et al) states that in the November 2021 Proposal, EPA proposed to find that cost-effectiveness values up to \$1,970/short ton of methane reduced are reasonable. According to estimates by Rystad Energy, the costs of gas recovery options per metric ton of methane abated are well below the levels that EPA finds cost-effective.

- *Routing to a sales line*. The Rystad report shows that connecting wells to gathering infrastructure is not only highly cost-effective but profitable for operators, with an average net profit to operators of \$3.10 per thousand cubic feet (kcf) and average negative cost of \$162 per metric ton of methane flaring avoided.<sup>40</sup> Operators will pay between \$0.40 and \$0.80 per kcf handled by third party processing and gathering, netting profit after gas sales of \$2.70 to \$3.50 per kcf. This corresponds to a range of *negative \$141-183 per metric ton of methane abated*.<sup>41</sup> Gathering is an effective and available option for sites flaring any amount of gas.<sup>42</sup>
- *Onsite use*. Rystad estimates that on average, onsite use of gas nets a profit of \$8.60/kcf and \$449 per MT of methane flaring avoided, after accounting for cost savings from fuel switching.<sup>43</sup> For a site producing 50 kcf per day of associated gas, costs associated with onsite power generation include between \$1.90 to \$2.20 per kcf for a small power generator and between \$0.60 to \$1.70 per kcf for gas treatment, netting between \$7.70 to \$9.40 in profit per kcf.<sup>44</sup> This corresponds to a range of negative \$402-491 per metric ton

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<sup>39</sup> Memorandum to the Docket, Record [call record for meeting with INGAA].

<sup>40</sup> Rystad, *supra* note 394, at 11.

<sup>41</sup> *Id.* at 45.

<sup>42</sup> *Id.* at 40.

<sup>43</sup> Rystad, *supra* note 394, at 11.

<sup>44</sup> *Id.* at 50-51.

of methane abated.<sup>45</sup> Onsite use is an effective option for sites flaring a relatively small amount of gas (less than 100 kcf/day).<sup>46</sup>

- *Other beneficial use.* In the proposed rule, EPA categorizes CNG trucking as “another useful purpose.” Rystad’s report finds that on average, CNG trucking will cost operators \$1.8/kcf, or \$94 per metric ton of methane flaring avoided.<sup>47</sup> At a site producing 250 kcf per day of associated gas, costs associated with CNG include between \$0.60 to \$1.70 per kcf for gas treatment, \$0.30 to \$1.00 per kcf for compression, and \$2.60 to \$4.10 per for 200 miles of transportation, for a net cost after gas sales of between \$0.10 to \$3.40 per kcf.<sup>48</sup> This corresponds to a range of \$5 to \$177 per metric ton of methane abated. CNG is an effective option for sites flaring more than 250 kcf/day of gas and is scalable across a range of sites.<sup>49</sup>
- *Reinjection.* Reinjection for storage costs vary depending on various factors, but Rystad finds that on average, costs are \$3.4/kcf, and \$177 per metric ton of methane flaring avoided.<sup>50</sup> Costs associated with reinjection include between \$0.20 and \$0.60 per kcf for gathering and between \$0.20 and \$5.70 per kcf for storage, for a total cost between \$0.40 to \$6.30 per kcf.<sup>51</sup> This corresponds to a range of \$20 to \$329 per metric ton of methane abated. Reinjection is an effective option for sites flaring more than 350 kcf/day of gas.<sup>52</sup>

Commenter (2433-EDF et al) states that while EPA declined to quantitatively analyze these alternatives in the November 2021 TSD, stating, “the site-specific variabilities associated with the application of these control options are significant,”<sup>53</sup> and did not include a quantitative assessment of non-flaring abatement options in the 2022 TSD, the Rystad cost analysis estimates discussed above, which are broadly applicable across basins, offer a pathway to assessing costs and emissions reductions.

Commenter (2433-EDF et al) states that EPA quantitatively analyzed the use of a combustion control device to abate emissions from associated gas venting at five model plants in the December 2022 TSD.<sup>54</sup> Additionally, as Rystad notes, associated gas from nearby well pads could be aggregated together to increase the applicability of capture options.<sup>55</sup> As discussed, the commenter provides that all capture options are highly cost-effective based on cost per metric ton of methane flaring abated (and are even more cost-effective if assessed as abatement options for uncontrolled methane venting).

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<sup>45</sup> Id. at 51.

<sup>46</sup> Id. at 40.

<sup>47</sup> Rystad, supra note 394, at 11.

<sup>48</sup> Id. at 56.

<sup>49</sup> Id. at 40–41.

<sup>50</sup> Rystad, supra note 394, at 11.

<sup>51</sup> Id. at 69.

<sup>52</sup> Id. at 40.

<sup>53</sup> U.S. Env’t Protection Agency, Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG), at 13–5 (Oct. 2021) (Dkt. No. EPA-HQ-OAR-2021-0317) [hereinafter Initial TSD].

<sup>54</sup> Supplemental TSD, supra note 121, at chapter 6, attachment 7.

<sup>55</sup> Rystad, supra note 394, at 40.

Similarly, commenter (2408-CO-LGC) suggests that eliminating routine flaring is a cost-effective way to curb methane emissions. They refer to the above-cited environmental commenters submitted detailed analysis included in their comments submitted to the EPA on the November 2021 proposal documenting that the four-abatement options EPA proposes here are cost effective.<sup>56</sup> Specifically, they repeat:

- The Rystad report shows that connecting wells to gathering line infrastructure is not only highly cost-effective but profitable for operators, with an average net negative cost of \$3.10 per thousand cubic feet (mcf) and \$162 per MT of methane flaring avoided.<sup>57</sup>
- Rystad estimates that on average, on-site use of gas nets a profit of \$8.60/mcf and \$449 per MT of methane flaring avoided.<sup>58</sup>
- Rystad's report finds that on average, CNG trucking will cost operators \$1.8/kcf, or \$94 per MT of methane flaring avoided.<sup>59</sup> In the Proposed Rule, EPA views CNG trucking as falling into the "another useful purpose" category.
- Reinjection costs vary depending on various factors, but Rystad finds that on average, costs are \$3.4/mcf, and \$177 per MT of methane flaring avoided.<sup>60</sup>

Commenter (2408-CO-LGC) states that the costs of the abatement options are well below EPA's cost-effectiveness threshold. In the November 2021 Proposal and the 2022 Supplemental Proposal, EPA proposes to find that cost-effectiveness values up to \$1,970/ton of methane reduction are reasonable for controls identified as BSER.

Response II-6-19: EPA reviewed the Rystad report submitted by the commenter. EPA does not agree or disagree with the conclusions of the report on the cost-effectiveness of the alternatives to BSER. EPA does not need to agree or disagree to support our BSER determination. EPA analyzed routing to a sales line as BSER and concluded that in most cases for new wells, routing to a sales line is BSER. EPA also recognizes that some sources will seek alternatives to BSER where they find it to their advantage to use an alternative to BSER, for logistical, cost, or other reasons. The only justification required of an existing source is where every alternative is infeasible for technical or safety reasons, and the source determines that the only technical means of handling associated gas is to flare. This is an option available to modified and existing sources only after the alternatives have been documented to be infeasible. For sources that produce 40 tpy or less of associated gas, no justification is required to flare because our BSER analysis indicated that routing to a sales line was not reasonable for BSER even over short distances to a sales or gathering line.

Comment: Commenters (2168-INOGA, 2172-KOGA) believe that if industry was able to cost effectively transport the gas to a sales line and monetize the benefit, it would have been done

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<sup>56</sup> Env't Def. Fund et al., Comments on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Dkt. No. EPA-HQ-OAR-2021-0317-0844 (Jan. 31, 2022) (Hereinafter "Joint Environmental Comments").

<sup>57</sup> Rystad Energy, Cost of Flaring Abatement, Slide 11 (Jan. 31, 2022) (Hereinafter "Rystad"), Ex. W to Joint Environmental Comments.

<sup>58</sup> Id.

<sup>59</sup> Id.

<sup>60</sup> Rystad, Slide 11.

already. The challenge is that commercial gas lines are not in proximity to some the oil production. Industry has been sharing this information in our comments since 2015 when NSPS OOOOa was proposed.

Further, commenter (2168-INOGA) states that when industry proposes to construct a new gas pipeline to route the gas to sales (for environmental “benefit”), environmental groups oppose the project through litigation. The commenter notes that the EPA is maintaining this position; but has not supported the oil and gas industry through the process to provide take-away capacity to move the gas to market.

Commenters (2168-INOGA, 2172-KOGA) point out that much of the associated gas from low production wells does not meet the requirements to be sold on an interstate pipeline system. The gas may require water, nitrogen, carbon dioxide, and heavier hydrocarbons (ethane, propane, butane, pentane, and hexane) to be removed prior to being sold into the gas market. The cost to make the gas “pipeline spec” usually exceeds the benefit of selling the gas on the pipeline. The commenter provides that this is another example of where low production wells should be exempt from the proposed regulation.

Response II-6-20: See Response II-6-19 of this Chapter.

Comment: Commenter (2428-API) states the EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document the commenter reports that the EPA states:

There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tons per year (tpy) to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year.

Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.

Commenter (2428-API) states within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporarily flare associated gas when the primary recovery method is not available (i.e., routing to sale, for injection, or used as onsite fuel). However, the commenter notes that the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

Response II-6-21: EPA is finalizing standards that do distinguish between facilities that temporarily flare gas for an interruption in service for routing to sales, for injection, or used of onsite fuel, apart from routine long-term flaring. In the finalized version of 40 CFR 60.5377b(c), EPA has specified reasons and periods that flaring may be used to achieve 95 percent control efficiency, unless a safety issue makes flaring unsafe. Each of these occurrences generates a record of deviation from the standard.

### **6.2.3 Proposed BSER - EG OOOOc**

[**Note**: Most of the comments provided on the proposed NSPS OOOOb also apply to EG OOOOc. For these comments, see section 6.2.2 of this Chapter. This section includes comments that specifically provided comments on the existing sources/EG OOOOc.]

#### 6.2.3.1 Opposition to Proposed EG OOOOc BSER

Comment: Commenter (2294-OOGA) suggests that the fundamental flaw in EPA's NSPS OOOO regulations has resulted in a misguided BSER determination for existing sources that effectively regulates existing sources the same as new and modified sources. The commenter states that the December 2022 supplemental proposal assumes that existing facilities can be retrofitted at a reasonable cost to meet the same emissions standards applicable to new and modified sources. The commenter contends that the EPA made a gross miscalculation in this regard. The commenter provides that many of their members lack the financial capital to retrofit existing sources with the equipment necessary to comply with the emissions standards under the supplemental proposal and/or do not have technical staff and legal advisors to assist with understanding and complying with the myriad of requirements that they will be subject to, including AVO inspections, conducting root cause analyses and fixing leaks, recordkeeping and reporting (not to mention the significant costs associated with conducting those activities). Even assuming operators could pay for costs to retrofit, the commenter explains that, as a well approaches the end of its useful life, there is a point at which it is no longer economic to make the necessary retrofits. Whereas EPA assumed compliance to be feasible and cost-effective, the commenter asserts that the reality is that the stringent emissions standards under the supplemental proposal will render many existing operations, particularly low production wells, economically infeasible and drive many small business and operators of low production wells out of business, including landowners of the approximately 5,300 wells that provide oil/gas to single-family residences in Ohio. [**Note**: For further comments received on low production well concerns, see sections 6.2.2.4 and 6.2.3.3 of this Chapter.]

Response II-6-22: While the scope of this comment is beyond associated gas requirements, EPA disagrees that differences in existing and new sources have not been considered in the development of NSPS OOOOb and EG OOOOc. This is particularly evident for associated gas, where the standards in the final NSPS OOOOb and the presumptive standards in EG differ considerably. Recognizing the barriers to retrofitting existing sites to route the associated gas to a sales line or use the gas for another beneficial purpose, the final EG OOOOc includes an allowance for owners and operators of existing wells to demonstrate the technical infeasibility and route the gas to a flare. For small low producing wells such as those described by the commenter, EPA recognized the cost burden the final EG OOOOc allows routing to a flare or

control device without a technical infeasibility demonstration. This is defined by the methane level containing the associated gas. Specifically, wells producing natural gas containing 40 tons of methane or less per year are eligible for this provisions.

Further, with regard to those wells that are approaching their remaining useful life, state agencies have the option to invoke the RULOF provisions and develop standards less stringent than the presumptive standards in EG OOOOc.

#### 6.2.3.2 Existing Well Site Considerations

Comment: Commenter (2283-Endeavor Energy) suggests that EPA should clarify the requirements for demonstrating that operational flaring is necessary and that the proposed flaring requirements do not apply to emergency flares. As with many of the other proposed requirements, the commenter is concerned that EPA's proposed provisions related to flaring do not reflect the realities of the environments in which the commenter and other producers operate. The commenter asserts that this is particularly true for existing sites. Under the Methane Proposal, EPA proposes that before associated gas can be flared, the owner or operator must submit a demonstration, certified by a professional engineer or other qualified individual, that a sales line is unavailable and other beneficial uses are not feasible for technical or safety reasons. The commenter explains that, for many of their existing wells, no sale line is readily available, and even if one was available, the volume of associated gas may be too low to reach a sales line. The commenter recommends that EPA reconsider this requirement for existing well sites, in recognition that the infrastructure is unlikely to be present to make such a requirement feasible.

Commenter (2283-Endeavor Energy) states that EPA's proposed provisions present several additional problems when applied to existing well sites. The commenter provides that many older, existing well sites in the Midland Basin do not have flares onsite, and it would present a significant capital expense to add a flare or similar control device at each existing well site. In addition, under the Methane Proposal, well owners or operators routing associated gas to a sales line that anticipate that there may be interruptions in the ability to route the associated gas to a sales line must provide a technical or safety demonstration in their annual report and install and operate a control device that achieves the required reduction during these temporary periods. The commenter states that this provision would effectively require a backup flare at every well site, which they say would impose substantial costs if applied to existing well sites. According to the commenter (and provided elsewhere in their comments), these requirements threaten to fundamentally alter the economics for these existing wells and could result in wells being shut in or abandoned. The commenter believes that the EPA should therefore consider the remaining useful life of these existing sources, as required by the CAA, and should not include these requirements in any finalized EGs.<sup>61</sup>

Response II-6-23: See Responses II-6-10 and II-6-21 of this Chapter.

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<sup>61</sup> 42 U.S.C. §741 l(d)(I).

### 6.2.3.3 Low Production Wells

Comment: Commenter (2446-IPAA) provides comment on the implications of the EG on low production wells, where EPA's recurring conclusion that designated facilities under the EG should be the same as affected facilities under the NSPS fails to understand the implications of inherent production depletion on the economics and emissions from smaller wells. The commenter asserts that there are fundamental factors that are not adequately considered in the EPA assessments. As oil and natural gas wells undergo their inherent depletion, the reduced volumes of production limit the amount of emissions that can be generated. Within the well itself, one key factor is the reduction of the internal pressure of the well. Lower well pressure may compel actions like the addition of pumps to pull the liquids out of the well bore, as well as the addition of compressors to pull gas from the well bore. Even natural gas-powered pneumatic controllers and pumps may not be able to function if the well pressure drops below the level needed to run the controller or pump, and consequently the well does not produce as a function of negative pressure. As a result, well sites must be reconfigured to reflect their aging operations. All these factors also influence the magnitude – even the possibility – of emissions. A natural gas well with a booster compressor is typically operating under negative pressure - trying to pull gas from the well. As opposed "to leaking" the system would be pulling ambient air into the gas product stream, not having it leak from flanges and valves. As wells diminish, they do not necessarily operate – or emit – daily. Small wells may only operate a few days a week when the pumper comes to the site to operate the equipment to produce oil from a well bore that has slowly filled over the previous days. The commenter asserts that these factors affect the realistic design of regulations – including the potential definitions of designated facilities – that EPA has not addressed in the EG.

Response II-6-24: See Responses II-6-10 and II-6-21 of this Chapter.

### 6.2.3.4 EG OOOOc Regulatory Text

Comment: Commenter (2288-North Dakota Department of Environmental Quality (NDDEQ)) cites the proposed language in 40 CFR 60.5420c(c)(2)(ii)(B) which reads "[r]ecords of each change been [sic] made at the site since the original certification along with records of either a re-certification of why it is infeasible to comply with 40 CFR 60.5391c(a)(1), (2), (3), or (4) in accordance with 40 CFR 60.5391c(b)(2), or a statement that indicates compliance can now be achieved with 40 CFR 60.5391c(a)(1),(2), (3), or (4) and a description of specifically how compliance will be achieved." The commenter states it is unclear what type of change would require records to be kept under this requirement.

To avoid any confusion, the commenter (2288-NDDEQ) suggests the type of change requiring records to be kept should be explicitly defined, as in 40 CFR 60.5420c(b)(9)(ix) "change in the reported condition", or in 40 CFR 60.5415c(e)(1) "change in compliance method". Presumably, the commenter believes, the change required in 40 CFR 60.5420c(c)(2)(ii)(B) should refer to change "that would impact the ability to comply with §60.5391c(a)(1), (2), (3), or (4)", per 40 CFR 60.5420c(b)(3)(ii)(B)(1).



Additionally, commenter (2288-NDDEQ) points out that 40 CFR 60.5420c(b)(3)(ii)(B) appears to reference incorrect paragraphs. They note that it currently states, "[f]or each oil well with associated gas that complies by routing the gas to a control device that reduces methane emissions by at least 95.0 percent, the information in either paragraphs [40 CFR 60.5420c] (b)(4)(ii)(B)(1) or (2) of this section." Presumably, the commenter believes, since it is referencing its own paragraphs, it should instead reference "paragraphs [40 CFR 60.5420c](b)(3)(ii)(B)(1) or (2) of this section" instead.

Commenter (2237- North Dakota Industrial Commission (NDIC)) points out several of the same regulatory text concerns as commenter (2288-NDDEQ) does. For example, commenter (2237-NDIC) contends that the proposed language in 40 CFR 60.5420c(c)(2)(ii)(B) is confusing. It reads:

Records of each change been [sic] made at the site since the original certification along with records of either a re-certification of why it is infeasible to comply with §60.5391c(a)(1), (2), (3), or (4) in accordance with §60.5391c(b)(2), or a statement that indicates compliance can now be achieved with §60.5391 c(a)(1), (2), (3), or (4) and a description of specifically how compliance will be achieved.

The commenter (2237-NDIC) suggests that it is unclear what type of change would require records to be kept under this requirement. To avoid confusion, the commenter recommends that the type of change requiring records to be kept should be explicitly defined, as in 40 CFR 60.5420c(b)(9)(ix) "change in the reported condition", or in 40 CFR 60.5415c(e)(1) "change in compliance method". They also recommend that the type of change required in 40 CFR 60.5420c(c)(2)(ii)(B) should refer to change "that would impact the ability to comply with §60.5391c(a)(1), (2), (3), or (4)", per 40 CFR 60.5420c(b)(3)(ii)(B)(1).

Additionally, the commenter (2237-NDIC) states (as commenter 2288-NDDEQ does above) that 40 CFR 60.5420c(b)(3)(ii)(B) appears to reference incorrect paragraphs. It currently states:

For each oil well with associated gas that complies by routing the gas to a control device that reduces methane emissions by at least 95.0 percent, the information in either paragraphs (b)(4)(ii)(B)(1) or (2) of this section.

Since it is referencing its own paragraphs, the commenter (2237-NDIC) believes it should instead reference "paragraphs (b)(3)(ii)(B)(1) or (2) of this section".

Response II-6-25: The proposed provisions related to the recordkeeping requirement to document certain changes that trigger a re-assessment of the technical infeasibility have not been retained in the final rule. Rather, all associated gas wells that are allowed to routinely flare because they have demonstrated and certified the technical infeasibility of routing to a sales line and other beneficial uses are required to perform a new demonstration and re-certify technical infeasibility on an annual basis.

Comment: Commenter (2214- BlueCrest Alaska Operating, LLC (BlueCrest) ) requests clarification of 40 CFR 60.5420c(b)(3)(ii)(A) regulatory text. Does the identification of each

well that routes gas to a control device include unplanned facility upsets that result in well gas being routed to a flare when it is normally routed to a production facility?

Response II-6-26: See Response II-6-6 of this Chapter.

#### **6.2.4 Flaring**

[**Note:** In addition to the comments provided in this section, section 17.x of Chapter 17 includes general comments that support the banning of flaring of associated gas and use as a control device option for other affected/designated facilities subject to NSPS OOOOb and EG OOOOc.]

##### 6.2.4.1 Environmental and Human Health Implications of Flaring

Comment: Commenter (2392-Earthjustice et al) states that disparate air quality impacts are associated with flaring practices at oil and gas extraction facilities. These adverse health impacts are widespread and severe. The commenter reports that flaring of associated gas at oil wells produces black carbon particles, more commonly referred to as soot or particulate matter (PM). The respiratory impacts resulting from exposure to particulate matter can travel as far as 60 miles away from flaring sites.<sup>62</sup> Studies confirm a causal link between flaring and respiratory-related hospitalizations in North Dakota, where a recent study found that a 1 percent increase in the amount of flared natural gas in the state increases the respiratory-related hospitalization rate by 0.73 percent.<sup>63</sup> Therefore, the commenter urges EPA to strengthen the proposed rule to mitigate the above disparate impacts.

Commenter (2433-EDF et al) points out that flaring and venting also contribute a significant amount of methane emissions annually. In 2019, flaring emitted 86,000 metric tons of methane and venting emissions emitted 68,000 metric tons of methane. The commenter notes that these estimates likely underestimate methane emissions from associated gas flaring and venting, as they do not account for observed high rates of unlit and malfunctioning flares. The commenter reports that studies also demonstrate that emissions from flaring and venting cause severe health burdens on communities, especially disadvantaged communities like low-income populations, people of color, the elderly, and children.

A 2023 study by Boston University's School of Public Health, The University of North Carolina, and the commenter (2433-EDF et al) has analyzed the impacts of onshore oil and gas flaring and venting on air quality and health.<sup>64</sup> The commenter (2433-EDF et al) indicates that prior studies have indicated that oil and gas activity is associated with increased risk of adverse health events, but there was limited quantification of the health impacts that resulted from air pollution from flaring and venting activities. This study sought to fill this gap by quantifying ozone, fine particulate (PM<sub>2.5</sub>) and nitrogen dioxide (NO<sub>2</sub>) emissions from venting and flaring and attributing those emissions to particular health outcomes. Using a hybrid Visible Infrared Imaging

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<sup>62</sup> Wesley Blundell & Anatolii Kokoza, Natural Gas Flaring, Respiratory Health, and Distributional Effects, 208 J. of Pub. Econ. 104601, 22 (2022), <https://www.sciencedirect.com/science/article/abs/pii/S0047272722000032>.

<sup>63</sup> Id.

<sup>64</sup> See Huy Tran et al., Onshore Oil and Gas Flaring and Venting Activities in the United States and their Impacts on Air Quality and Health (pre-publication slides) (Feb. 2023) (included as Attachment Q).

Radiometer Suite (VIIRS) and the National Emissions Inventory (NEI) based emissions inventory and applying Community Microscale Air Quality (CMAQ) and Benefits Mapping and Analysis Program (BenMAP)-R to assess air quality health impacts, the study found that in 2017, flaring and venting emissions from oil and gas operations resulted in 710 premature deaths, 73,000 asthma exacerbations among children, 210 instances of ozone national ambient air quality standards (NAAQS) exceedances, and over \$7.4 billion in health damages.<sup>65</sup> Critically, the commenter notes that the study has found that these health impacts disproportionately burden disadvantaged populations. Of the adult deaths and child asthma exacerbations caused by venting and flaring, one in three are among low-income populations, and one in five are in communities that are home to Native American populations.<sup>66</sup> The study also looks at specific pollutant emissions and their impacts. It finds that flaring and venting contributes to 50 percent of VOC emissions from oil and gas facilities across the continental U.S., 63.1 percent in Texas, 84.6 percent in North Dakota, 52 percent in New Mexico, 70.6 percent in Colorado, and 58.8 percent in Wyoming. And that ozone (O<sub>3</sub>) pollution from flaring and venting contributes to 230 deaths, 9,700 asthma exacerbations, and 110 respiratory hospitalizations annually.<sup>67</sup>

Commenter (2433-EDF et al) states that the 2023 study results complement previously published literature, including a 2022 study by Rice University and Clean Air Task Force, which looked at the health impacts related to black carbon emissions from flaring in the U.S.<sup>68</sup> This study used satellite flaring data from VIIRS and three separate reduced form models to assess flaring health impacts. It estimated that flaring from oil and gas operations emitted nearly 16,000 tons of black carbon in 2019, leading to 26-53 premature deaths that were directly attributable to air quality associated with flares, mostly in Texas, North Dakota, and New Mexico.

According to the commenter (2433-EDF et al), they conducted an additional analysis that focused on the impacts of flaring on disadvantaged communities living near oil and gas sites. To conduct this analysis, the commenter used Enverus data to identify wells with reported flaring in 2019 (available for the following states: TX, NM, CO, ND, MT, WY, and MS). By identifying wells with flaring, the commenter was able to identify the local communities that are impacted by the air pollution from these wells. Using the methodology described in Proville et. al. 2022,<sup>69</sup> the U.S. Census Bureau's American Community Survey 5-year estimates for 2015-2019,<sup>70</sup> and health data from the Centers for Disease Control and Prevention's Places dataset,<sup>71</sup> the commenter was able to estimate the populations living within a half mile radius of the previously identified wells using areal apportionment.

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<sup>65</sup> Id. at 4–5.

<sup>66</sup> Id. at 5.

<sup>67</sup> Id. at 31.

<sup>68</sup> Chen Chen et al., Black Carbon Emissions and Associated Health Impacts of Gas Flaring in the United States, 13 *Atmosphere* 385 (Feb. 2022), <https://www.mdpi.com/2073-4433/13/3/385/htm>.

<sup>69</sup> Jeremy Proville et al., The demographic characteristics of populations living near oil and gas wells in the USA, 44 *Population Env't.* 1 (2022), <https://doi.org/10.1007/s11111-022-00403-2> (Attachment R of their comment submission).

<sup>70</sup> U.S. Census Bureau, 2015–2019 American Community Survey 5-year Estimates (2021) (retrieved from [https://www2.census.gov/geo/tiger/TIGER\\_DP/2019ACS/](https://www2.census.gov/geo/tiger/TIGER_DP/2019ACS/)).

<sup>71</sup> Centers for Disease Control and Prevention, Places: Local Data for Better Health, <https://www.cdc.gov/PLACES/> (last visited Feb. 13, 2023).

From this analysis, the commenter (2433-EDF et al) estimates there are roughly 240,000 people living within a half mile of a well with flaring. This includes approximately 19,000 children under the age of five, more than 28,000 older Americans over the age of 65, 110,000 people living in poverty, and almost 120,000 people of color, including 7,400 Native Americans and 94,000 Hispanic/Latinos. Because flaring data at the well level is only available for seven states, it is likely that these numbers are higher. Several of these demographic groups are over-represented in the population living in proximity to flaring, relative to the nation at large. For example, Native Americans live near actively flaring wells at rates 80 percent higher than the national average. Nationally, Hispanic/Latinos make up about 20 percent of the overall population, but 40 percent of those living near a flaring well identify as Hispanic/Latino. Among those near flaring, asthma, chronic obstructive pulmonary disease (COPD), coronary heart disease (CHD), and stroke are found at rates 4-8 percent higher than the rest of the country. Roughly 17,000 adults with asthma, 13,000 adults with COPD, 12,000 adults with CHD, and 6,500 adults who have experienced a stroke live within a half mile of a flaring well.

Commenter (2433-EDF et al) states that these results comport with previous findings, including a 2021 study by researchers at the University of California-Los Angeles (UCLA) and University of Southern California (USC) that found that more than half a million people in the U.S. live within a half mile of significant oil and gas flaring.<sup>72</sup> Of these people, the study found, 210,000 live near more than 100 flares, including a disproportionate number of black and indigenous people and other people of color.

The commenter (2433-EDF et al) asserts that these studies show the significant health impacts of flaring and that they disproportionately impact vulnerable communities. They highlight the critical need to address emissions from associated gas at oil wells. As noted in section I (A), EPA's proposal will reduce methane emissions from associated gas by roughly one million metric tons between 2023-2035. EPA standards could reduce associated gas methane emissions by an additional 400,000 tons (to at least 1.4 million tons)<sup>73</sup> over this period if strengthened as outlined below. Doing so will also substantially reduce the health impacts flaring has on local communities. Like flaring and venting emissions estimates, the commenter (2433-EDF et al) suggests these emission reductions estimates are likely undercounted as they do not account for reductions that could be achieved by reducing unlit and malfunctioning flares.<sup>74</sup>

Response II-6-27: While these comments encompass the impacts of flaring in general and are not limited to associated gas flaring, EPA points out that BSER for the final NSPS OOOOa and EG OOOOc is to route the associated gas to a sales line. In addition, the standards and presumptive standards also allow the use of other options that achieve the same level of emission reduction as routing to a sales line. Flaring is only allowed in limited circumstances. EPA believes that the final associated gas standards and presumptive standards will be effective in reducing the impacts of flaring such as those mentioned by the commenters.

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<sup>72</sup> Lara J. Cushing et al., Up in smoke: characterizing the population exposed to flaring from conventional oil and gas development in the contiguous US, 16 Env't Rsch. Letters 034032 (Feb. 2021), <https://iopscience.iop.org/article/10.1088/1748-9326/abd3d4>.

<sup>73</sup> See infra section IV.A.

<sup>74</sup> See infra, section IV.B.

Comment: Commenter (1648-PA-Audubon) states methane flares present a hazard to birds from burning, entrapment in pipes or vents, or direct mortality from the flare. The flame emitted to burn off gas during a flaring event can attract birds, especially at night, explains the commenter, and birds may fly through the superheated gas or flame, resulting in feather damage which grounds the birds, or scalding of lungs and other tissues with inhalation. The commenter also reports that birds can also be killed or injured if they perch on burner pipes.

Response II-6-28: See Response II-6-27 of this Chapter.

Comment: Commenter (2502-RGISC) states that they conducted over 100 oil and gas inspections in the Eagle Ford shale and have seen firsthand how harmful methane pollution from the oil and gas industry is to health and the planet. The commenter states that on any given day a smoking flare, unlit flare, or leaking tanks could be spotted. The commenter states that there are communities along the Eagle Ford Shale, like Tilden, Texas, that smell of hydrocarbons, day in and day out, due to the sheer volume of gas being vented and flared.

Commenter (2028-WMCG) points to a study by a research team from the University of California, Los Angeles (UCLA) and University of Southern California (USC) which examined the relationship between poor birth outcomes and shale gas development in south Texas. The commenter explains that the study specifically considered proximity to flaring events, studied the birth outcomes from mothers exposed to the most flaring events, based on satellite observations, within a five-kilometer radius of their homes during pregnancy and compared them to the birth outcomes from mothers who were not exposed to flaring events during their pregnancies. Between these two groups the researchers saw 50 percent higher odds of preterm birth and shorter gestation in the group exposed to flares<sup>75</sup>.

Commenter (2028-WMCG) also points out that the Ventura County Air Pollution Control District, in California has estimated that the following air pollutants may be released from natural gas flares: benzene, formaldehyde, polycyclic aromatic hydrocarbons (PAHs, including naphthalene), acetaldehyde, acrolein, propylene, toluene, xylenes, ethyl benzene and hexane. The commenter adds that researchers in Canada have measured more than 60 air pollutants downwind of natural gas flares, states the commenter and deadly hydrogen sulfide and radon-226 has also been shown to exist in shale gas.

Commenter (2028-WMCG) provides that in 2014, a four-part investigation by the San Antonio Express-News found that natural gas flaring in the Eagle Ford Shale in 2012 contributed more than 15,000 tons of VOCs and other contaminants to the air of southern Texas—which is roughly equivalent to the pollution that would be released annually by six oil refineries.

Commenter (2352-ETRPC) notes Texas accounts for 47 percent of vented and flared natural gas in the U.S, and the commenter states they have seen firsthand how harmful that pollution can be. The commenter includes examples of interviews they conducted across the Permian Basin from people living and working in the region, including ranchers, oil and gas attorneys, and others

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<sup>75</sup> Cushing et al., 2020.

with industry ties. The commenter states that they are posting these example interviews at EnvironmentTexas.org.

Commenter (2352-ETRPC) provides that Dr. Edward Brooks, a physician and specialist in immunology, has also expressed concerns with health impacts in communities located close to a refinery or high production area. The commenter warns that flaring releases compounds, such as benzene, a known carcinogen or toluene, a neurotoxin. The commenter refers to a recently published study examining the Eagle Ford Shale region that found that “pregnant women who lived near areas where flaring is common had 50 percent greater odds of giving birth prematurely than those who did not.”

Response II-6-29: See the Response II-6-27 of this Chapter.

Comment: Commenters (1620-EEN, 2039-CPLV) states that when companies rush to extract oil, many forgo investments necessary to capture and sell methane and instead flare it as a waste product, emitting a host of climate and health-harming pollutants. The commenter warns that flares have been found to malfunction or fail entirely, spewing methane directly into the atmosphere. Commenter (2039-CPLV) asserts that reducing venting and flaring will significantly decrease methane, an extremely potent GHG, as well as smog-causing VOC emissions and carcinogens.

Response II-6-30: See Response II-6-27 of this Chapter.

#### 6.2.4.2 Exclusion/Limitation of Flaring

Comment: Commenters (1611-ELPC, 1620-EEN, 1633-NRDC, 1643-ORVI, 1644-YECA, 1648-PA Audubon, 1651-CJM, 1658-PDT, 2028-WMMCG, 2036-NPCA, 2152-CALSTRS, 2156-CCGD, 2164-NAM, 2174-Progress MI, 2185-NY CRF, 2190-M/H Investments, 2191-Boston Trust, 2195-EHP, 2199-RMFU, 2203-Ceres, 2206-L&G Investment, 2215-WVRC et al Rivers, 2217-RACRJ, 2236-PA PSR, 2242-SGI, 2250-NRPE et al, 2278-Springfield NAACP, 2285-Bailard, 2287-ICCR, 2289-Galilee Baptists, 2299-NEI Investments, 2303-NTAA, 2335-Loren Karro, 2352-ETRPC, 2356-Earthworks et al, 2364-CleanEarth4Kids, 2365-CA CA, 2388-ExxonMobil, 2394-Earthworks, 2404-DRC, 2407-Methane Action, 2410-CA AG et al, 2420-WHPCA, 2422-WLN, 2424-As You Sow, 2429-WOC, 2441-HAWC, 2447-CALN, 2459-BMO Global Assets, 2461-CRS, 2466-KM, 2502-RGISC, 2766-1000 Grandmothers, 3418-Maine Solar Energy Association) urge the EPA to build on the proposed framework to address flaring by ensuring that operators at wells capture associated gas and limit flaring of that gas to instances in which it is necessary for safety or maintenance reasons. Many commenters point to flaring regulations in Colorado and New Mexico and ask the EPA to reflect those regulations in the proposed rule.

Commenter (2447-CALN) states that communities of color have been shown to experience disproportionate exposure to natural gas flaring.<sup>76</sup> If flaring must occur, the commenter states it

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<sup>76</sup> Johnston, Jill E., Khang Chau, Meredith Franklin, and Lara Cushing. "Environmental Justice Dimensions of Oil and Gas Flaring in South Texas: Disproportionate Exposure among Hispanic Communities." *Environmental Science & Technology* 54, no. 10 (May 19, 2020): 6289-98. <https://doi.org/10.1021/acs.est.0c00410>.

should continuously meet the 95 percent threshold in terms of reductions of methane and VOCs and it should never be considered a long-term solution. The commenter recommends that the EPA carefully weigh the benefits of requiring owners and operators capturing gas for "beneficial" uses such as on-site power or reinjecting into wells for enhanced oil recovery with the potential climate, safety, and environmental justice impacts of these measures.

Commenter (2028-WMMCG) believes that the current proposal does not go far enough. The commenter is concerned that the current draft would continue to allow unnecessary gas flaring and venting if a company claims it is unable to capture and repurpose gas. The commenter states that EPA's proposal that ensures flares meet requirements for good flare performance, including the requirement to continuously monitor the flare to ensure that a pilot flame burns at all times are wholly insufficient because flaring is toxic and a hazard to public health.

Response II-6-31: See Response II-6-27 of this Chapter.

Comment: Commenter (2433-EDF et al) strongly supports EPA's exclusion of flaring as a compliance option for reducing associated gas from oil wells. But while flaring is no longer a compliance option, operators nonetheless can flare if they demonstrate that each of the gas recovery options is not technically feasible or safe. This is true for operators of new and existing wells. Moreover, the commenter adds that the EPA does not propose to limit the volume or amount of time an operator can flare upon submission of its technical infeasibility demonstration. The commenter description of their concerns with the technical infeasibility exception are presented below. In particular, the commenter urges EPA to revise the standard to limit the instances when an operator may flare temporarily by replacing the proposed technical infeasibility exemption with a set of clearly delineated circumstances in which temporary flaring or venting may be warranted.

Commenter (2433-EDF et al) states that the technical infeasibility exemption, as proposed, does not distinguish between instances when an operator seeks to flare on a routine, ongoing basis, and those instances when an operator seeks to flare on a temporary basis. This is one example of the over-breadth of the exemption. According to the commenter, as these and prior comments demonstrate, ongoing, routine flaring is rarely, if ever, a necessary part of operations. Furthermore, the commenter contends that the technical infeasibility exemption presents enforcement challenges. Below the commenter describes the reasons why they believe this exemption is overly broad.

First, commenter (2433-EDF et al) suggests safety concerns are by their nature temporary and would never give rise to the need to flare indefinitely. EPA should therefore require that any safety-related flaring cease when the safety concern no longer exists.

Second, commenter (2433-EDF et al) suggests routine flaring from new wells can never be justified due to the technical infeasibility of some alternative. As discussed in both the Rystad report and the expert report of Tom Alexander, the commenter states that routine flaring is readily preventable at new wells with proper planning and coordination between upstream and

midstream operators.<sup>77</sup> The commenter adds that the Rystad report makes clear that the main drivers of flaring are timing of well hookups and infrastructure capacity.<sup>78</sup> An operator has complete control over decisions regarding where and when to drill a new well and when to complete or put such a well into production.<sup>79</sup> As such, the commenter states that operators of new wells have the ability to address both timing and infrastructure capacity challenges.

Third, commenter (2433-EDF et al) states that routine flaring from existing wells is also avoidable or preventable.<sup>80</sup> In the event an existing well is not currently connected to a gathering line, cost-effective options in addition to routing to a gathering line are available, including converting the associated gas to compressed natural gas (CNG), using it to replace a different fuel source for onsite fuel purposes, converting the gas to electricity, or injection or reinjection.<sup>81</sup> The commenter notes that prudent operators are prepared for events that can result in loss of takeaway capacity such as midstream and downstream interruptions, changes in gas composition requirements, and changes in line pressure.<sup>82</sup> The commenter contends that such operators can quickly employ one of the alternative abatement options EPA proposes.<sup>83</sup>

Commenter (2433-EDF et al) suggests that in the event an operator loses its connection to a gathering line without warning due to events outside its control, a limited exception for flaring during the upset condition can address an operator's need to flare temporarily (discussed further below).<sup>84</sup> Operators can also temporarily shut in wells if time is needed to restore access to a pipeline or make arrangements for alternative gas recovery. The commenter states that shutting in wells does not necessarily harm the productivity of a well and may, in some instances, enhance performance.<sup>85</sup> Additionally, the commenter notes that the CAA section 111(d) implementation process as proposed gives operators of existing wells significant time (i.e., approximately four-and-a-half years after rule finalization) to implement one of the four approved alternative uses for associated gas. In those rare instances when an operator of an existing well is unable to capture, put to beneficial use, or inject or reinject associated gas after this lengthy runway due to truly unique and extenuating circumstances, it may request a variance in a state plan pursuant to the remaining useful life and other factors (RULOF) provisions.

Fourth, commenter (2433-EDF et al) believes the exemption presents enforcement challenges. While an operator's demonstration of technical infeasibility must be signed and certified as to its truth, accuracy, and completeness, the commenter provides that there is no requirement that EPA review and approve this demonstration prior to an operator flaring. Rather, operators must retain records of the certified demonstration and provide it to EPA as part of annual reporting. This

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<sup>77</sup> Thomas Alexander, Alexander Engineering, Expert Report of Thomas Alexander 2 (2023) [hereinafter, Expert Report of Thomas Alexander] (Attachment V).

<sup>78</sup> Rystad, *supra* note 394, at 8 (noting that Infrastructure capacity constraints account for 84 percent of flaring in ND and 62 percent of flaring in TX).

<sup>79</sup> 2022 Joint Environmental Comments, *supra* note 1, at 187, 194.

<sup>80</sup> Expert Report of Thomas Alexander, *supra* note 435, at 4.

<sup>81</sup> 2022 Joint Environmental Comments, *supra* note 1, at 187; Expert Report of Thomas Alexander, *supra* note 435, at 4.

<sup>82</sup> Expert Report of Thomas Alexander, *supra* note 435, at 4.

<sup>83</sup> *Id.*

<sup>84</sup> *Id.* at 4-5.

<sup>85</sup> *Id.* at 3.



raises the possibility that flaring will occur in the absence of a full, accurate, complete, or otherwise adequate demonstration.<sup>86</sup> In order for EPA to identify any problems or shortcomings in the certified demonstration, it must review the operator's documentation, but this review will necessarily occur after an operator has flared, potentially for a considerable amount of time. The commenter states that this opens the door to extended periods of flaring in violation of the rules.

Response II-6-32: See Responses II-6-10 and II-6-21 of this Chapter. EPA disagrees that it is necessary for EPA to review each demonstration by a facility that BSER and the alternatives are infeasible, and therefore the sources must flare associated gas. EPA has delegated authority to permitting agencies that have capacity to oversee sources in their jurisdiction.

Comment: Commenter (2410-CA AG et al) urges EPA to adopt NSPS and EG that effectively prohibit routine flaring of associated gas from new and existing oil wells, with the only exceptions related to safety and emergencies, by requiring owners or operators to capture all or most of the gas. Flaring is a major source of emissions of many harmful air pollutants. When functioning properly, flares emit large amounts of CO<sub>2</sub> and nitrogen oxides (NO<sub>x</sub>). When malfunctioning, which is common, they emit substantial amounts of methane, VOC, and hazardous air pollutants (HAP) directly into the atmosphere.<sup>87</sup> The commenter recommends that EPA should follow the states' (noted CA and NM state requirements) lead and prohibit routine flaring of associated gas from new and existing oil wells except in very limited cases such as emergencies and for safety reasons. If EPA continues to allow flaring of associated gas for technical feasibility reasons, the commenter contends that EPA should also take steps to disallow the indefinite continuation of routine flaring. The commenter believes that it would be appropriate to limit the allowable time for flaring to 12 months. If after 12 months an owner or operator does not connect its facility to a gathering line or otherwise put gas to beneficial use, EPA should require the operator to shut in a well until it is connected to a gathering line, or the gas is put to beneficial use.

At a minimum, the commenter (2410-CA AG et al) requests EPA further strengthen flaring restrictions to ensure that the need to flare is well-documented, continues to be necessary, and does not become routine. The commenter asserts that the EPA should require more frequent certifications than annual reports to demonstrate why all potential beneficial uses, including emerging techniques, are not feasible due to technical or safety reasons. When there is any change in circumstances, they add that owners and operators should be required to perform a more thorough analysis and engineering certification comparable to the initial certification required once an owner or operator becomes subject to the rule. For instance, the commenter agrees, as EPA suggests, that it would be appropriate to require an owner or operator to provide an additional engineering certification that flaring is the only option where a new gathering pipeline is installed within a certain distance of an oil well.

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<sup>86</sup> Expert Report of Thomas Alexander, *supra* note 435, at 6-7.

<sup>87</sup> See, e.g., Environmental Defense Fund, Permian Methane Analysis Project, available at <https://data.permianmap.org/pages/flaring> (finding in seven random surveys of routine-flaring sites, flare malfunctions ranged from 3.3 percent to 11.5 percent and when expanded to all well sites, including lower-production wells, flare malfunctions jumped from 29 percent to 36 percent).

Response II-6-33: See Responses II-6-10 and II-6-21 of this Chapter.

Comment: Commenter (2392-Earthjustice et al) strongly supports EPA's proposed requirement that owners and operators of oil wells with associated gas must capture that gas and route it to a sales line. However, they believe that the EPA can and should take further steps to eliminate routine flaring. They assert that the EPA should replace the broad technical infeasibility exception that would allow operators to continue routinely flaring with narrowly defined exemptions applicable only to short-term and temporary flaring. Alternatively, they add that EPA should revise and strengthen the certified technical infeasibility demonstration by requiring independent third parties to conduct the demonstration and requiring additional documentation to prove that no other gas recovery options are available.

Commenter (2392-Earthjustice et al) states that enacting these recommended improvements will reduce rates of routine flaring that disproportionately impact tribal communities, like those of the Fort Berthold Reservation in North Dakota, as well as Black and Latine communities. The commenter contends that action to significantly reduce dangerous air emissions from these sources will result in major air quality and health benefits for the communities of color living near these sources.

Response II-6-34: See Responses II-6-10 and II-6-21 of this Chapter. EPA disagrees that it is necessary for a third party to verify an analysis showing that BSER and the alternatives are infeasible. The operator is ultimately responsible for a credible study of feasibility and has the option to enlist a third party or use personnel from their organization qualified to determine the feasibility of BSER or the alternatives. The demonstrations of feasibility will be subject to review by state permitting agencies with the requisite expertise to review the demonstrations to determine their credibility.

Comment: Commenter (2365-Climate Action California) argues that oil companies should be required to work out arrangements with pipeline companies/contractors and gas processing plants to ensure that their associated gas can be transported away and sold. They add that being able to flare this excess gas should not be an option.

The commenter (2365-Climate Action California)) explains that most routine flaring occurs at oil wells that are unable to pipe their associated gas to a sales line, either because they are 1) not connected to a natural gas gathering pipeline, or 2) the local pipeline or the downstream processing plant has insufficient capacity to collect or use its gas, or 3) the gathering pipeline is experiencing maintenance problems. In other words, the flaring problem is created by a lack of off-site infrastructure. How can the EPA's final rule contribute to solving this problem? They suggest the following:

- A start would be to require that all oil well applications for a permit to drill (APDs) include a waste minimization plan indicating how the owner plans to minimize the need for venting and flaring associated gas. Plans indicating how a well will be connected to a gathering pipeline should be a condition of receiving approval if other nearby, worthwhile uses for the gas are not feasible.

- If the waste minimization plan will not prevent most flaring, the EPA should have the authority to delay approval until all associated gas can be used on site or removed for some productive use.
- If the gathering lines are already operating at capacity, the applicant could apply for approval for construction of a new gathering line. If the downstream processing plant is at capacity application approval should be delayed until more capacity comes on line.
- The commenter recommends that flaring of associated gas beyond a certain minimum level be disallowed, and hence subject to financial penalties. Since the EPA has chosen not to ban routine flaring, it must make it expensive. Penalties or fines should be large enough to push oil producers to work out infrastructure solutions. Oil companies will only devote time to solving their infrastructure problem if it is costly not to do so.

Commenter (2365-Climate Action California) refers EPA to the Bureau of Land Management (BLM) Proposed Rule on Waste Prevention, Production Subject to Royalties and Resource Conservation published on November 30, 2022. Section 3162.3-1 covers Drilling Applications and Plans and Section 3179.8 covers Oil-Well Gas.

Commenter (2365-Climate Action California) states that most of the flaring from BLM-managed oil and gas leases occurs at oil wells that are connected to a gas pipeline with insufficient takeaway capacity for the well(s) connected to the pipeline. The commenter explains that when the gas pipeline associated with an oil well becomes overwhelmed, the well is “kicked off” the pipeline and the operator is faced with a choice: flare the associated gas to continue oil production unabated or curtail oil production in order to conserve the associated gas.” While the royalty rate of 16.67 percent may not result in producers temporarily halting production, they note that, it at least provides an incentive to reduce flaring.

Commenter (2365-Climate Action California) states that the BLM proposal exempts the following emissions from royalties: emergency venting or flaring for up to 48 hours, gas used or consumed within a lease area and gas “unavoidably lost”. This last category includes well completions, production testing and downhole well maintenance. Neither the emergency nor the unavoidably lost category includes recurring equipment failures, inadequate equipment capacity, failure to limit production when it exceeds capacity of equipment, pipeline, or gas plant to handle—or exceeds sales contract volumes, scheduled maintenance, or operator negligence. (Section 3179.105)

- The BLM proposal requires that all applications for an oil well drilling permit (APDs) include a waste minimization plan (Section 3162.3-1(j)). “The waste minimization plan would need to demonstrate how the operator plans to capture associated gas upon the start of oil production, or as soon thereafter as reasonably possible, including an explanation of why any delay in the capture of the associated gas would be necessary.” This rule will enable the BLM to determine the likely amount of flaring should the drilling permit be issued. The BLM can defer action on the permit application by informing the applicant what additional steps must be taken to reduce the likelihood of flaring (Section 3162.3-1(k)).
- The BLM proposal sets a royalty-free flaring limit of 1050 thousand cubic feet (Mcf) per month per lease, flaring above this limit would be subject to a 16.66 percent royalty rate.

(Section 3179.8(a)) The BLM estimates that this flaring limit would make approximately 85 percent of flared volumes royalty-bearing. The BLM proposal also gives the BLM authority to curtail production of oil if flaring gas exceeds 4000 Mcf per month for 3 consecutive months. (Section 3179.8 paragraphs (b) and (c)).

- The BLM's proposed rule includes the authority to fine a producer \$1000 immediately on discovery that a flare is not lit. (Section 3179.6(b)) EPA should have similar authority.

Commenter (2365-Climate Action California) continues by stating that an EPA requirement that oil drilling permit applications include a plan to minimize venting or flaring associated gas should bring with it the agency's authority to delay permit approval until further steps are taken to reduce the need for routine flaring. If a lack of pipeline capacity occurs for a producing oil well and the owner does not want to temporarily curtail production, EPA would be able to impose time and volume limits on gas flaring and fine producers at the same rate the BLM is proposing. The commenter contends that, since the EPA chose not to ban routine flaring and venting, it needs to make flaring and venting more costly for producers.

A recent EDF study of gathering line methane emissions in the Texan Permian Basin<sup>88</sup> estimated them to be 14 times the EPA national inventory estimate. Fortunately, gas gathering pipelines came under federal oversight in November 2021. The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) should now be receiving annual reports on all safety incidents. Commenter (2365-Climate Action California) recommends that the EPA work with PHMSA to determine how maintenance on existing gathering pipelines can be improved to reduce pipeline shutdowns and methane emissions, and how insufficient capacity in gathering pipelines can be corrected. The commenter further recommends that the EPA strategize with the Department of Energy (DOE) to determine how offsite infrastructure improvements can reduce the need to flare, especially in the Permian Basin.

Response II-6-35: See Responses II-6-10 and II-6-21 of this Chapter. It is beyond the scope of the NSPS to address safety concerns under the jurisdiction of PHMSA, or to address gathering capacity directly. To the commenter's suggestion that EPA collaborate with the DOE, the commenter does not specify which offsite infrastructure that EPA should collaborate on.

Comment: Commenter (2453-Carbon Mapper-RMI) states that under the supplemental proposal, EPA is proposing to require operators and owners to prioritize alternative beneficial reuse options for associated gas from oil wells utilizing a hierarchy of standard control options, and all options must be exhausted prior to resorting to flaring at a site via requesting a variance. The first demonstration and request for variance would require certification by a professional engineer or approved equivalent, and subsequent reports would require simply reporting whether circumstances have changed regarding the need to flare. The commenter notes that the EPA also seeks comment on details and triggers required to continue and/or re-analyze granted variances.

As the impetus for the rule is prevention of the indefinite use of flaring, the commenter (2453-Carbon Mapper-RMI) supports that flaring variances last for a finite period and/or volume (whichever is reached first). New usable sales pipelines or other infrastructure, feasible delivery

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<sup>88</sup> <https://blogs.edf.org/energyexchange/2022/10/04/research-shows-gathering-pipelines-in-the-permian-basin-leaking-14-times-more-methane-than-officials-estimate/>.

points for compressed gas, technology, or discoveries in additional beneficial uses may present themselves as available later in the asset's life. As proposed in the rule, the commenter also supports that such triggers (variance age, volume flared, or new developments/innovations) should trigger a new, full, and certified review similar to original variance requests.

Commenter (2453-Carbon Mapper-RMI) adds that they support EPA requiring operators to attempt to access an existing sales line, the preferred standard control option, and facilitate alternative off-site transport and use of associated gas. Furthermore, since sites operate for decades and sales lines are typically not under the control of the well owners and operators, the commenter recommends that operators include an attempt to collaborate with gathering system owners regarding both upcoming or proposed sales line projects and production projects, as this may inform and optimize sales lines route engineering. If enough operators collaborate with gathering system owners, gathering system owners may respond to the demonstrated need of sales pipelines in unserved/underserved areas. Otherwise, they note that pipelines may not be developed due to a lack of discussion and identification of opportunity.

The commenter (2453-Carbon Mapper-RMI) states that the supplemental proposal and the existing regulations do not contain provisions to directly validate or verify destruction efficiency unless a flare is detected as part of the Super-Emitter Response Program. The commenter recommends that EPA remain abreast of studies and data available that would indicate improvements in flare performance based on requirements. Furthermore, they add that the supplemental proposal requires use and performance monitoring of a pilot flame used for flaring at all times, "unless a demonstration has been made that the [net heating value] NHV of the inlet gas to the flare consistently exceeds the operating limit established in the rule." The commenter believes, similar to the above discussion regarding flaring variances, that this demonstration should be subject to a time- and/or volume-based limitation and should require re-submittals to ensure that original conditions granting such an exception persist.

Response II-6-36: See the response to II-6-10 and II-6-21. Regarding flare requirements, the commenter is incorrect that a pilot flame must be monitored unless a demonstration is made that the NHV of the inlet gas is consistently above the required limit. The December 2022 Supplemental Proposal required flare pilot flames to be monitored at all times. In the final rule, we have augmented this monitoring by requiring an alert to the control room whenever the pilot flame is not lit. Additionally, in the final rule we have added a requirement that the pilot flame does not need to be monitored if the owner or operator is approved for an alternative test method that continuously monitors the combustion efficiency of the flare. Regarding the inlet gas NHV demonstration that can be used in lieu of continuously monitoring the NHV of the inlet gas to the flare, in the final rule we have added an ongoing five-year sampling requirement to ensure the inlet gas NHV remains sufficiently high. These requirements are discussed in more detail in Sections X.H and XI.H of the preamble to the final rule.

Comment: Commenter (2408-CO-LGC) reiterates the comments they previously submitted to EPA on its initial proposal which called for a nation-wide ban on the wasteful and unnecessary practice of routine flaring. By routine flaring the commenter means ongoing, continuous flaring in the absence of a method for capturing and selling, putting to beneficial use, or storing

associated gas.<sup>89</sup> The commenter points out that leading state examples and the commitments made by multiple operators demonstrate eliminating routine flaring is feasible and cost effective.

As the commenter (2408-CO-LGC) contends that their prior comments made clear, Colorado and New Mexico have largely banned this pernicious practice and the commenter urges EPA to do the same. Colorado's rule provides: "[V]enting and Flaring of natural gas represent waste of an important energy resource and pose safety and environmental risks. Venting and Flaring, except as specifically allowed in this Rule 903, are prohibited."<sup>90</sup> Similarly, New Mexico's rule provides: "[V]enting or flaring of natural gas during drilling, completion, or production operations that constitutes waste as defined in 19.15.2 NMAC is prohibited. The operator has a general duty to maximize the recovery of natural gas by minimizing the waste of natural gas through venting and flaring. During drilling, completion and production operations, the operator may vent or flare natural gas only as authorized [through specific regulations]."<sup>91</sup> The commenter adds that Alaska has also largely banned this practice, allowing operators to flare only during specific, narrowly conditioned exceptions.<sup>92</sup>

Commenter (2408-CO-LGC) also notes that that numerous operators have committed to eliminate routine flaring as part of the World Bank's Zero Routine Flaring by 2030 Initiative. To date, 54 oil companies and 34 governments have endorsed the "Zero Routine Flaring by 2030" Initiative. Based on satellite estimates and publicly reported flaring data, together the endorsers represent around 60 percent of global flaring.<sup>93</sup> The commenter adds that Exxon Mobil recently announced a commitment to end routine flaring while also expressing support for regulations banning this wasteful practice.<sup>94</sup>

Commenter (2408-CO-LGC) urges EPA to revise its proposal to prohibit routine flaring by requiring operators use one of the four gas recovery abatement methods included in EPA's proposal. They suggest that EPA allow for flaring only during explicit, narrowly tailored, and time-limited, exemptions. They believe that, by doing so, it would more clearly and unequivocally prohibit pollution stemming from routine flaring, as well as enhance the enforceability of the rule.

Specifically, commenter (2408-CO-LGC) urges EPA to abandon the broad, unclear technical infeasibility exemption and instead delineate those instances in the rule where temporary flaring is allowed, subject to reasonable, limitations. According to the commenter, doing so is consistent with the approach in Colorado and New Mexico.

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<sup>89</sup> The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative, <https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#8>.

<sup>90</sup> 2 Colo. Code Regs. § 404-1-903.

<sup>91</sup> N.M. Code R. § 19.15.27.8(A).

<sup>92</sup> 20 Alaska Admin. Code § 25.235(d)(1)-(6).

<sup>93</sup> World Bank website, Zero Routine Flaring by 2030 (ZRF) Initiative, <https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030>.

<sup>94</sup> Reuters, Exxon Halts Routine Gas Flaring in The Permian, Wants Others to Follow (Jan. 24, 2023), <https://www.nasdaq.com/articles/exclusive-exxon-halts-routine-gas-flaring-in-the-permian-wants-others-to-follow>

The commenter (2408-CO-LGC) explains that, during an upset condition operators may need to flare or vent for a limited period. Notably, upset conditions are conditions outside of the control of an operator that can interrupt the ability of the operator to comply with the proposed standard. An example of an upset condition is temporary loss of connection to, or ability to route gas to, a gathering system. EPA has determined that interruptions of an operator's ability to route gas to a gathering system constitute a technical or safety reason that can justify flaring and is taking comment on requirements to address this circumstance.<sup>95</sup> The commenter agrees that interruptions to an operator's connection to a gathering system can result in the need for operators to flare on a temporary basis. However, they believe that routine flaring is avoidable and should not be permitted during these circumstances.

Commenter (2408-CO-LGC) provides that both Colorado and New Mexico allow operators to flare or vent gas for a short period of time during upset conditions or emergencies which include temporary unavailability of access to a gathering line. They explain that the Colorado rules provide a concise, clear definition of upset condition combined with a limit on the amount of time an operator may flare or vent during such circumstances. Colorado allows operators to vent or flare for up to 24 cumulative hours during an upset condition while New Mexico allows operators to vent or flare for up to 8 hours during an emergency. Loss of a connection to a pipeline qualifies as an upset condition under the Colorado rules and an emergency under the New Mexico rules.

The commenter (2408-CO-LGC) continues to explain that Colorado's definition of an Upset Condition is "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction." This definition does not include "an operator's negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance."<sup>96</sup> Colorado limits venting and flaring to a period necessary to address the upset, not to exceed 24 cumulative hours and requires operators maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each upset condition.<sup>97</sup> This definition includes "sudden unplanned lack of pipeline capacity."<sup>98</sup> Accordingly, Colorado allows operators to vent or flare associated gas in the event that disruptions to a gathering system interrupt the ability of an operator to route associated gas to a sales line, but only up to 24 cumulative hours.<sup>99</sup>

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<sup>95</sup> 87 Fed. Reg. at 74,780.

<sup>96</sup> COGCC SBP, 800/900/1200 Rule Series, p.76, available at <https://drive.google.com/drive/u/0/folders/1kTZUgXmhVpOy4gEZ2tSOYVDDvYXupzvA>.

<sup>97</sup> 2 Colo. Code Regs. § 404-1-903(d)(1)(A).

<sup>98</sup> COGCC SBP, 800/900/1200 Rule Series, p.76.

<sup>99</sup> Colorado also allows operators to request approval to flare for a longer period, up to 12 months, in the event of loss of access to a gathering line due to unforeseen circumstances outside of the operator's control. An operator may only request approval once, however. To avail itself of this option, an operator must request permission to flare within 30 days of loss of access to a gathering line and cannot flare unless approval is granted. This request must be accompanied by detailed information demonstrating why the well cannot be connected to infrastructure, when the well will be connected to infrastructure, options for using the gas, including to generate electricity, gas processing to recover natural gas liquids, or other options for using the gas, an estimate of the volume and content of the gas to be flared and a gas analysis. 2 Colo. Code Regs. § 404-1-903.d.(3).

The commenter (2408-CO-LGC) adds that New Mexico similarly allows for temporary venting or flaring during an emergency. An emergency means “a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment” other than in certain exceptions. One such exception is “venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, an unscheduled maintenance, or a malfunction of a natural gas gathering system.”<sup>100</sup> In other words, they explain that an upstream operator may vent or flare during a temporary, infrequent, and unavoidable event involving loss of connection to a sales line provided the midstream operator notifies the producer of the disruption to the operator of the sales line. However, an upstream operator cannot vent longer than 8 hours in this circumstance.<sup>101</sup> The commenter recognizes that there may be instances when an operator loses connection to a sales line for reasons other than during an emergency of upset condition, such as where the midstream operator ceases to operate the gathering line or where the demand for the gathering line exceeds its capacity. The commenter does not believe flaring or venting should be permitted in these circumstances. These are foreseeable risks that prudent operators can and should plan for. As discussed above, prudent operators should have equipment in place to utilize associated gas for other beneficial purposes (e.g., compression for conversion of natural gas to CNG) in the event of a loss of takeaway capacity. New Mexico does not allow operators to vent or flare during non-emergency losses of takeaway capacity.<sup>102</sup> An operator’s failure to limit production when the production rate exceeds the capacity of the related equipment or natural gas gathering system, or exceeds the sales contract volume of the natural gas, do not constitute emergencies during which an operator may vent or flare.<sup>103</sup> Colorado contains a limited exception that allows operators to request permission to flare in the event of loss of connection to a sales line, but this exception is only available once to an operator, and to qualify for it an operator must demonstrate there are no alternative options available to recover the gas.<sup>104</sup> The commenter states that they do not believe such an exception is warranted with proper planning.

The commenter (2408-CO-LGC) recommends EPA limit flaring (or venting) during an upset condition not to exceed 24 cumulative hours per R.903.d.(1)(A). This would apply in those instances where a disruption to a gathering system or other event causes an interruption to an operator’s ability to route the gas to a sales line.

Specifically, commenter (2408-CO-LGC) urges EPA to abandon the broad, unclear technical infeasibility exemption and instead delineate those instances in the rule where temporary flaring is allowed, subject to reasonable, limitations. The commenter notes that doing so is consistent with the approach in Colorado and New Mexico.

Commenter (2408-CO-LGC) Another circumstance that may give rise to an operator’s need to vent or flare on a temporary basis is during the commissioning of pipelines, equipment, or facilities. New Mexico allows operators to vent or flare temporarily during pipeline equipment or

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<sup>100</sup> N.M. Code R. §19.15.27.7.H.

<sup>101</sup> Id. at § 19.15.27.7.H.(4).

<sup>102</sup> Id. at § 19.15.27.7.H.(4).

<sup>103</sup> Id.

<sup>104</sup> 2 Colo. Code Regs. § 404-1-903.d.(3).



facilities commissioning.<sup>105</sup> New Mexico limits waste during this activity to “only for as long as necessary to purge introduced impurities.”<sup>106</sup> When starting up operation of new equipment, there is often water (used to hydro test) or solids (from stimulation flowback) that need to be purged from the equipment or pipeline. This can only be done by releasing this gas with untreatable impurities to atmospheric tanks which allows for the small volumes of gas to also be released until a stable hydrocarbon stream is achieved. While New Mexico does not limit the amount of time an operator may need to vent or flare during this exception, operators have an incentive to limit venting or flaring to a minimum as the sooner they connect the well to a gathering line, the sooner they are able to route the gas to sales.

In addition, the commenter (2408-CO-LGC) provides that operators may also need to flare temporarily where an operator is connected to a sales line, but natural gas does not meet pipeline specifications, and where the other three compliance options are also unavailable.<sup>107</sup> This occurs where impurities such as nitrogen are present in the associated gas and thus the gas cannot safely be sent to the sales line. New Mexico requires the operator take specific steps to limit flaring during this circumstance as follows:

Operators must analyze gas samples twice a week to determine if pipeline specifications have been achieved; must route gas into gathering pipelines when pipeline specifications are met and must provide pipeline specs and NG analyses to division upon request.<sup>108</sup>

The commenter (2408-CO-LGC) notes that New Mexico does not include a specific time-limit for this exemption. However, per the example above, operators have a profit incentive to limit flaring or venting.

The commenter (2408-CO-LGC) provides that another exemption provided is during active or required maintenance. Both Colorado and New Mexico allow for temporary venting and flaring during maintenance activities. Colorado specifies that maintenance must be active and required “to clarify that while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited.”<sup>109</sup> Colorado requires operators use best management practices to minimize venting during maintenance and repair activity. New Mexico similarly allows venting or flaring during repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance.<sup>110</sup> The commenter recommends that EPA allow flaring and venting during active and required maintenance activities, provided not otherwise prohibited by EPA or state rules.

Commenter (2408-CO-LGC) states that Colorado and New Mexico also allow for temporary flaring during production tests and production evaluations. Colorado defines a production test to

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<sup>105</sup> N.M. Code R. § 19.15.27.8.D.(4)(m).

<sup>106</sup> Id.

<sup>107</sup> N.M. Code R. § 19.15.27.8.D.(4)(l).

<sup>108</sup> Id.

<sup>109</sup> COGCC SBP, 800/900/1200 Rule Series, p. 84.

<sup>110</sup> N.M. Code R. § 19.15.27.8.

mean “a test for determination of a reservoir’s ability to produce economic quantities of oil or gas.”<sup>111</sup> Colorado defines a production evaluation as “an evaluation of production potential for determination of requirements for infrastructure capacity and equipment sizing.”<sup>112</sup> Colorado allows venting or flaring during both events, but only subject to pre-approval from the Director. If the operator has obtained approval, the rules permit venting or flaring up to a period not to exceed 60 days.<sup>113</sup> New Mexico limits venting or flaring during a production test for a period not to exceed 24 hours absent approval for a longer test period.<sup>114</sup> The commenter recommends that EPA allow venting or flaring during this exception yet limit the duration of 24 hours as Colorado has done.

Commenter (2408-CO-LGC) adds that limited venting or flaring may also occur when operators conduct monitoring activities to inspect downhole well integrity. Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.<sup>115</sup> Per the Statement of Basis and Purpose for Colorado’s rule, bradenhead monitoring activities should be limited to 30 minutes.<sup>116</sup> New Mexico allows operators to conduct packer leakage tests, which is another form of downhole monitoring.<sup>117</sup> In both instances, the commenter suggests that venting and flaring be limited to 30 minutes.

Response II-6-37: See section XI.F.2 of the final rule preamble for a comprehensive discussion of EPA’s BSER determination for the final rule.

Comment: Commenter (2452-Hess, 3843-Hess) recommends that EPA should align any requirements relating to routine flaring of associated gas with the World Bank’s zero routine flaring initiative by using consistent definitions and concepts. EPA has noted that it “is taking comment on steps the Agency should consider taking to disallow the indefinite continuation of routine flaring.” The commenter agrees with EPA that flaring during production operations should be minimized. The commenter recently endorsed the World Bank’s “Zero Routine Flaring by 2030” initiative and has set a target to eliminate routine gas flaring (consistent with the World Bank’s definitions) at all our operated production sites by the end of 2025, five years ahead of the World Bank’s commitment date. To support the achievement of this objective, the commenter continues to focus on the buildout of gas infrastructure in the Bakken and consider additional flare reduction initiatives globally. However, the commenter is concerned that the associated gas requirements in the Supplemental Proposal unnecessarily restrict innovative, cost-effective, and performance-based approaches to emissions reductions and create regulatory uncertainty.

Commenter (2452-Hess) believes that flaring of associated gas should be defined and regulated in a way that is consistent with the World Bank’s “Zero Flaring by 2030” initiative, which defines routine flaring as “flaring that occurs during the normal production of oil, and in the

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<sup>111</sup> 2 Colo. Code Regs. § 404-1-100-15.

<sup>112</sup> 2 Colo. Code Regs. § 404-1-100-14.

<sup>113</sup> 2 Colo. Code Regs. § 404-1-903.d.(1)(C).

<sup>114</sup> N.M. Code R. § 19.15.27.8.D.(4)(k).

<sup>115</sup> N.M. Code R. § 19.15.27.8.D.(4)(i).

<sup>116</sup> COGCC SBP, 800/900/1200 Rule Series, p.86.

<sup>117</sup> N.M. Code R. § 19.15.27.8.D.(4)(j).

absence of sufficient facilities to utilize the gas onsite, dispatch it to a market or reinject it.”<sup>118</sup> The World Bank approach acknowledges that the appropriate time to restrict flaring is after the well begins normal production. Gas capture needs during initial production operations can vary significantly depending on well-specific conditions, which may require flaring. In contrast, they note that once a facility has reached a state of normal production, gas capture needs are more predictable, and operators can better avoid flaring scenarios. As currently written, the restrictions on associated gas in the Supplemental Proposal apply throughout production operations, without any consideration of the different circumstances that may necessitate flaring. According to the commenter, this lack of distinction is inconsistent with the commonsense approach adopted by the World Bank and ignores practical considerations on-site. The commenter asserts that the EPA should not apply a single approach to the treatment of associated gas during the entirety of production operations.

Further, commenter (2452-Hess) points out that EPA’s proposed language allows flaring for “technical or safety reasons,” but does not provide operators with an understanding of what types of activities may qualify. In contrast, the World Bank’s proposal expressly acknowledges on-site realities and excludes safety flaring and non-routine flaring. As the World Bank notes in its FAQ, “safety flaring is both small in volume and essential for the safe operation of oil and gas production facilities. Non-routine flaring is often unforeseen in nature. For example, the commenter explains that it could be due to issues with the operation of the facility, and as such is hard to mitigate.”<sup>119</sup> Examples of safety flaring include blow downs to prevent overpressure, pilot flame gas, purge/fuel gas, gas containing H<sub>2</sub>S, and gas with high levels of volatile organic compounds (VOC) other than methane.<sup>120</sup> The commenter adds that non-routine flaring is typically intermittent and of short duration. It can include activities like temporary failure of equipment, failure of customer facilities that prevents receipt of gas, startup and shutdown activities, maintenance activities, process upsets, construction activities and facility modifications, and well testing, among other things.<sup>121</sup> The World Bank’s express exclusions for safety and non-routine activities better reflect operational constraints and provide more guidance to operators than EPA’s undefined “technical or safety reasons” throughout the Supplemental Proposal.

In addition, commenter (2452-Hess) states that while EPA’s preamble suggests an intent to view these stages separately, the plain language of 40 CFR 60.5377b applies to “each oil well with associated gas at a well affected facility.” Absent a clear distinction, the commenter suggests that this appears to conflict with the well completion obligations at proposed 40 CFR 60.5375b, which establish different requirements for flaring. Different regulatory and operational considerations apply during flowback. To avoid confusion in implementation, the commenter requests that EPA clarify that the requirements of 40 CFR 60.5377b only apply during

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<sup>118</sup> See Global Gas Flaring Reduction Partnership Gas Flaring Definitions (June 29, 2016), available at World Bank Document.

<sup>119</sup> See World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative Frequently Asked Questions and Answers, available at <https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#37>.

<sup>120</sup> See Global Gas Flaring Reduction Partnership, Gas Flaring Definitions (June 29, 2016), available at World Bank Document.

<sup>121</sup> Id.

production operations and do not apply during the well completion operations covered by 40 CFR 60.5375b.

While the commenter (2452-Hess) states they are committed to reducing routine flaring, they believe that EPA should align its regulations with the World Bank's initiative, rather than what is currently proposed. They state that this approach is consistent with the U.S existing endorsement of the World Bank initiative and commitment to "provide a legal, regulatory, investment and operating environment that is conducive to upstream investments and to the development of viable markets for utilization of the gas and the infrastructure necessary to deliver the gas to these markets."<sup>122</sup> According to the commenter, adopting the World Bank's proposed definition of routine flaring is a logical next step in support of this commitment. They add that it would also reduce the concerns discussed above and would encourage operators to continue to pursue voluntary emissions reduction initiatives, such as the World Bank's Zero Routine Flaring Initiative.

Commenter (3843-Hess) reports that many companies are already committed to that effort, as is the U.S. government.

Response II-6-38: See Responses II-6-10 and II-6-21 of this Chapter. EPA carefully reviewed and considered The World Bank initiative information. Much of the final rule is consistent with the World Bank approach.

Comment: Commenters (1646-Commission Shift (CS), 2329-LSC-Sierra Club, 2352-Environment Texas Research and Policy Center (ETRPC) express concerns with oversight of oil and gas operations. Commenter (1646-CS) is concerned with a lack of transparency within the organization and believes the RRC has allowed oil and gas companies to disregard venting and flaring limits and well plugging requirements, to the detriment of health and safety. The commenter believes that the elected officials at the RRC have no reason to listen to the commenter's most vulnerable community members, stating that oil and gas companies have far too much influence over the agency.

Commenter (2352-ETRPC) states that over the last five years, the RRC has granted operators an average of about 4,800 flaring permits annually. In 2021, the commenter states that 68 billion cubic feet of gas were flared. The commenter cites to an interview with an oil and gas attorney, where concern was raised about state oversight, and concludes that EPA must use its federal authority to ensure enforcement. Further, the commenter wants to ensure that operators at wells capture gas and limit flaring to when it is necessary for safety or maintenance reasons. Commenter (1646-CS) requests EPA to finalize a strong methane rule without delay to ensure strong federal methane standards to protect health and slow climate change.

Commenter (2329-LSC-Sierra Club) states while Texas' laws limit flaring and venting, the commenter believes the regulations are filled with loopholes, and the RRC routinely grants exceptions to the limitations. Between FY 2009 and FY 2020, the commenter explains that more than 27,000 exceptions were granted to allow oil and gas operations to flare. The commenter

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<sup>122</sup> See World Bank, Zero Routine Flaring by 2030 Initiative Text, available at <https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/initiative-text>.

states it is important to note that under Texas laws, venting is allowed during the first 10 days of drilling oil and gas wells and have dozens of other exceptions in the Natural Resource Code. The commenter notes there have been some improvement in the last few years because of community pressure, including enhanced review and publishing the flaring exceptions online. Still, even with more attention, the commenter reports that between January 1, 2022, to January 1, 2023, about 3,700 exceptions were granted, with millions of pounds of methane being released into the atmosphere, explains the commenter.

Commenter (2502-Rio Grande International Study Center (RGISC)) states that while the RRC reports that the percentage of natural gas flared compared to the natural gas produced from oil and gas wells in Texas dropped from 2.28 percent to 0.65 percent in May 2021; the flaring data is coming from self-reporting operators, who the commenter believes traditionally do not operate in good faith. Regarding self-reporting, the commenter believes this also leads to the underreporting of emissions events and other malfunctions regulated by the Texas Commission of Environmental Quality (TCEQ). The commenter cites to a 2021 TCEQ annual enforcement report, where 5,362 incidents were reported as “excess emissions events,” but the reports shows that TCEQ issued findings in only 16 percent of those cases, and of those, it ordered corrective measures in only 19.

Commenter (2236-Physicians for Social Responsibility Pennsylvania (PSR-PA)) expresses similar concerns about self-reporting and enforcement. The commenter states that intentional gas flaring and venting in addition to accidental leaks are dangerous for communities as well as the climate. The commenter believes that existing regulations are not adequate and expresses concern with self-reporting and proper oversight and enforcement. The commenter suggests that EPA strengthen the rules and urges EPA to address permit violations.

Response II-6-39: EPA notes the concerns of the commenters related to the Texas RRC program. EPA has no jurisdiction over these regulations or their enforcement. Further, while the requirements of the final federal standards and presumptive standards may be incorporated into permits, violations of air quality or other types of permits are not under the statutory authority of these regulations.

However, the final NSPS OOOOb and EG OOOOc include rigorous compliance provisions, including monitoring, recordkeeping, and reporting, that will hold owners and operators accountable to ensure that the applicable requirements are met.

#### 6.2.4.3 Technical Infeasibility Exemption and Determination Requirements

Comment: Commenters (2028-Westmoreland Group (WMCG, 2039-Citizens to Preserve Ligonier Valley, Inc. (CPLV)) requests that EPA provide clarity on when it is technically feasible to flare due to lack of gathering lines-- how the agency will evaluate and approve/deny venting and flaring applications from operators, including what role states will have.

Response II-6-40: EPA cannot predict every possible reason that an alternative to BSER would be infeasible. For this reason EPA has required that qualified technical personnel certify any final determination because the factors may be site-specific, specific to the alternatives being

evaluated, and require detailed knowledge of the site location. The alternatives that EPA has offered are broad categories of non-emitting alternatives or activities that emit equivalent to BSER. Each of the options could have their own unique factor of infeasibility. A site may be unable to reinject the gas because the geology of the site may not be suitable for permanent reinjection. A site may not be able to access or construct a gathering line because it is surrounded or within jurisdictions where right of way will not be granted because of land use restrictions, historic preservation restrictions, or laws and ordinances to protect cultural resources.<sup>123</sup> A site may not be able to capture and convert the gas to compressed or liquid natural gas because the site itself is an existing facility and may not have physical space appropriate or sufficient to construct and operate such an operation, or may be so remote as to make regular or all-season truck traffic infeasible on access roads. While each of these factors could make an option infeasible, none of the examples we have provided likely apply to all of the alternatives. Where one alternative may be infeasible, two other alternatives could be feasible, but may have different capital and operating costs, and different cost mitigation projections based on the volume and quality of gas that could be captured or used. EPA chose not to be more prescriptive because as industry has stated repeatedly in comments to this proposal, conditions will vary across geography, age of facilities, types of wells, and volume of associated gas to be handled.

Comment: Commenter (2433-EDF et al) has considerable concerns with the proposed technical infeasibility exemption and accompanying infeasibility demonstration. However, should EPA retain a technical infeasibility exemption, the commenter states that the agency must improve the rigor and enhance the enforceability of the exemption by: (1) limiting flaring to instances of physical impossibility; (2) requiring pre-approval of any flaring occurring under the technical feasibility exemption, or at least public notification of such flaring; (3) requiring that an independent third party submit the technical infeasibility certification; (4) requiring operators to submit detailed, certified technical infeasibility documentation at least annually if they intend to flare; and (5) require additional records of flaring events.

As discussed above in a previous comment, commenter (2433-EDF et al) does not believe there are ever any instances where an operator must flare routinely due to technical infeasibility or safety. As such, the commenter recommends that EPA prevent pollution from routine flaring by requiring gas recovery except in the temporary, limited circumstances discussed above. However, if EPA nonetheless finalizes a technical infeasibility exemption that allows an operator to flare based on a certified demonstration of technical infeasibility, the commenter argues that the agency must limit the exemption by clearly delineating the “technical” reasons that would justify flaring in lieu of the four gas recovery options.

First, commenter (2433-EDF et al) suggests that EPA must make clear that a demonstration based on a claim that the four abatement options are not economical at a particular site is not sufficient or relevant. EPA has not proposed an exemption based on economic infeasibility. As discussed above, the commenter states that gas recovery options are cost-effective at a variety of sites. The commenter adds that the EPA clarifies elsewhere (e.g., in its well completion

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<sup>123</sup> See for example 25 CFR § 169.123 (a)(2) at [<https://www.ecfr.gov/current/title-25/chapter-I/subchapter-H/part-169/subpart-C/subject-group-ECFR7b7105daa80dc3a/section-169.123>].

requirements) that technical infeasibility does not include economic infeasibility, but rather is limited to circumstances like lack of infrastructure, engineering issues, and safety concerns.<sup>124</sup>

Second, the commenter (2433-EDF et al.) adds that the EPA must require operators to demonstrate the physical impossibility of each of the gas recovery options to claim the exemption to flare. The commenter provides potential physical impossibility demonstrations below for each abatement method:

- *Gathering Lines.* In order to claim that routing associated gas to sales lines is not technically feasible, an operator should be required to show that it is physically impossible to connect to a gathering line and that the operator used best efforts to do so. Thus, for example, constraints that can be overcome with timing considerations (e.g., delaying completion or production of wells), compression (e.g., adding compressors to boost low-pressure gas in order to add the gas to higher-pressure pipelines) or proper planning are not sufficient to demonstrate that access to a gathering line is technically infeasible.<sup>125</sup> In these instances, lack of access to a gathering line is technically feasible because it is physically possible to route gas to the line with some timing revisions or the addition of compression at the well site.
- *Another Useful Purpose.* To demonstrate that it is not technically feasible to use gas for another useful purpose that a purchased fuel or raw material would serve, such as conversion of associated gas to CNG, an operator must show that it is physically impossible to use the gas for another useful purpose. CNG transport services are widely available<sup>126</sup> and must be considered as another potential useful purpose in all flaring demonstrations. To demonstrate this option is not technically feasible an operator must show that it is physically impossible to convert associated gas to CNG at the wellsite due to physical or technical constraints and/or that CNG transport in the region is not available.
- *Onsite Fuel.* An operator must show that there is no way to use the associated gas as an onsite fuel source to demonstrate that this abatement option is technically infeasible. As our prior comments demonstrated<sup>127</sup> operators have options for using associated gas as an onsite fuel source, including use for onsite power needs (e.g., replacing diesel with associated gas) or using associated gas to power a small electricity generation plant that sends power to the grid. Thus, an operator would need to demonstrate that neither option is available either because an operator has no onsite power needs or power needs have been met with less gas than produced, there is insufficient associated gas to support a small electricity generation plant, or there is no local demand for the power, even if generated.
- *Reinjection.* To demonstrate that reinjection is technically infeasible, an operator must demonstrate that there is no subsurface reservoir or other storage available for reinjection.

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<sup>124</sup> U.S. Environmental Protection Agency, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, Final Rule, 81 Fed. Reg. 35824 (June 3, 2016), <https://www.govinfo.gov/content/pkg/FR-2016-06-03/pdf/2016-11971.pdf>.

<sup>125</sup> See e.g., Expert report of Thomas Alexander, *supra* note 435, at 7 (discussing efforts in North Dakota to find innovative methods of transporting oil to market in the absence of sufficient oil pipeline capacity).

<sup>126</sup> 2022 Joint Environmental Comments, *supra* note 1, at 187.

<sup>127</sup> *Id.* at 67; Expert report of Thomas Alexander, *supra* note 435, at 7.

Porous subsurface reservoirs are readily available in all states responsible for the majority of associated gas flaring, with the possible exception of North Dakota.<sup>128</sup> There is potential, however, for reinjection into saline aquifers in North Dakota.<sup>129</sup>

Response II-6-41: The final rule diminishes the prevalence of the infeasibility determinations and certifications and only allows routine flaring with a technical infeasibility determination and certification in circumstances where the well was drilled prior to the knowledge or expectation of a prohibition on routine flaring. Specifically, these circumstances are existing wells (addressed by the presumptive standards in EG OOOOc), new wells for which construction commenced after the December 6, 2022, supplemental proposal and the final rule, and modified or reconstructed wells. More discussion of this topic is provided in section XI.F.2.g of the final rule preamble.

Comment: Commenter (2433-EDF et al) recommends that EPA require certification by an independent third party. EPA has proposed to allow certification by either a professional engineer or a “qualified individual with expertise in the uses of associated gas.”<sup>130</sup> Notably, per EPA’s proposal, an operator could use an in-house engineer, other qualified individual, or a contractor. However, the commenter notes that there is no requirement that the individual be independent from the operator. Certification by an independent third party, rather than a professional engineer or a “qualified individual with expertise in the uses of associated gas,” either of whom could be an in-house individual or a person with significant ties to the company, will enhance the credibility and reliability of the report.<sup>131</sup> Certification by an independent third party of all demonstrations seeking a flaring exception is necessary to ensure a robust, complete, and accurate demonstration of the reasons underlying the flaring request.

Commenter (2433-EDF et al) requests that EPA should further clarify that both the certifier and the owner/operator may be subject to penalties for submission of a fraudulent or significantly flawed certification. The commenter notes that this clarification is consistent with EPA’s proposal for pneumatic pumps. EPA proposes to include a technical infeasibility exemption from the zero-emission pneumatic pump standard, provided an operator submits a demonstration certified by a qualified professional engineer or in-house engineer with relevant experience. EPA notes that it “is committed to ensuring that this technical infeasibility provision is not abused or used as a loophole . . .,” pointing to the potential for enforcement actions to be levied against both the owner/operator and certifier upon submission of a “fraudulent, or significantly flawed” certification. The commenter urges EPA to clarify that this same potential penalty is applicable to the submission of “fraudulent, or significantly flawed” certifications in the context of associated gas at the affected well facility, if EPA retains the technical infeasibility exemption.

Commenter (2433-EDF et al) suggests that operators seeking to routinely flare must submit a thorough analysis and engineering certification comparable to the initial certification each year.

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<sup>128</sup> Rystad, *supra* note 394, at 67.

<sup>129</sup> *Id.* at 67; Expert report of Thomas Alexander, *supra* note 435, at 7.

<sup>130</sup> Proposed 40 C.F.R. § 60.5377b(b).

<sup>131</sup> Maureen Lackner & Kristina Mohlin, *Env’t Def. Fund, Certification of Natural Gas with Low Methane Emissions: Criteria for Credible Certification Programs* 11 (2022), [https://blogs.edf.org/energyexchange/files/2022/05/EDF\\_Certification\\_White-Paper.pdf](https://blogs.edf.org/energyexchange/files/2022/05/EDF_Certification_White-Paper.pdf) (Attachment W).



The commenter recommends that this demonstration should include the same information as the initial demonstration, namely a detailed analysis documenting the technical infeasibility or safety reasons for the infeasibility and an explanation as to why none of the four gas recovery options are technically feasible or safe. This demonstration must also be certified by an independent third party.

Response II-6-42: As discussed at length in the proposed amendments to NSPS OOOOa published on October 15, 2018 (83 FR 52079), EPA determined that the use of in-house engineers to assess feasibility is appropriate. This concept is maintained in this final rule and emission guidelines.

EPA agrees with the commenter that annual re-evaluation and re-certification of the technical infeasibility of routing the associated gas to a sales line or for another beneficial purpose is warranted. The technical infeasibility determination and certification requirements are discussed in Section XI.F.2.g of the final rule preamble.

Comment: Commenter (2428-API) does not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas. The commenter notes that in the proposed rule, EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements “...these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent.” According to the commenter, this statement is evidence of EPA’s clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

Since EPA has already acknowledged in the preamble that situations where a well is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use and need to route gas to a flare do occur and are outside the control of the well operator, the commenter (2428-API) also does not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring, especially during these short intermittent periods. Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

Response II-6-43: EPA agrees with this commenter, and the final rule allows the temporary flaring of associated gas when the gas cannot be routed to the sales line or used for the other primary beneficial purpose. See the response to II-6-6 and Section XI.F.2.f of the final rule preamble.

Comment: Commenter (2326-AXPC) suggests that the BSER opt-out should include economic factors in addition to technical feasibility or safety. The commenter reports that the EPA concedes that it is proposing multiple regulatory requirements whose implementation would be so burdensome that they would be “technically infeasible” for some set of affected facilities. EPA thus gives affected facilities the ability to “opt out” of the performance standard if the affected facility can show that compliance with the performance standard would be infeasible for technical or safety reasons. As explained below, the commenter contends that “technically infeasible” is a misnomer and EPA should explicitly include economic factors in addition to a technical feasibility analysis.

Commenter (2326-AXPC) states that within EPA’s NSPS OOOOb/EG OOOOc regulations, EPA provides opt out for their regulatory requirements such as the ability to use an emissions control device to handle associated gas,<sup>132</sup> the continued use of pneumatic pumps driven by natural gas,<sup>133</sup> and the use of emitting gas well unloading methods.<sup>134</sup> Unfortunately, according to the commenter, EPA does not provide any information within the rule on how an affected facility is expected to demonstrate that the regulatory provision in question is “technically infeasible” in their case, other than a requirement that a professional engineer or other qualified individual so certify.

Because there is no explanation of technical infeasibility within the rulemaking, the commenter (2326-AXPC) evaluated what EPA has done in other CAA programs. For example, EPA’s regulations related to best available retrofit technology (BART) determinations under the regional haze program include some insight into how EPA might evaluate technical feasibility considerations.<sup>135</sup> According to EPA’s BART regulations:

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” As explained in more detail below, a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.<sup>136</sup>

Commenter (2326-AXPC) believes that while these regulations provide more context than EPA’s proposed NSPS OOOOb/EG OOOOc regulations, the BART regulation conflates economic factors and technical feasibility and does not specifically account for other factors related to potential implementation that may be critical to compliance. The “available” concept is inherently an economic concept as it relates to whether the item is commercially available

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<sup>132</sup> See, e.g., Proposed 40 CFR 60.5377b(b)(2).

<sup>133</sup> See, e.g., id. 40 CFR 60.5393b(c).

<sup>134</sup> See, e.g., id. 40 CFR 60.5376b(c)(2)(ii)(B)(2).

<sup>135</sup> See 40 C.F.R. Part 51, Appendix Y.

<sup>136</sup> Id. Appendix Y(D)(1).

– *i.e.*, that the price is at such a level that it can be produced commercially. If EPA was truly looking at considering technical feasibility without regard to economic viability, whether a technology is commercially available would be irrelevant. And to do so here, would be inappropriate, particularly given the definition of standard of performance. Under CAA section 111(a)(1), the commenter provides that a standard of performance means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator deems has been adequately demonstrated.<sup>137</sup>

By providing an opt-out, the commenter (2326-AXPC) states that the EPA inherently recognizes that BSER cannot be met at every facility. Thus, in making the demonstration that use of the opt out is appropriate, the costs of achieving such emissions reduction should be considered. Further, because EPA may only include standards that are determined to be adequately demonstrated, they believe that technical feasibility must include considerations such as: ability to access electrical power; landowner access; other local or state regulatory requirements; and other considerations that limit the ability to comply with the standard of performance. In other words, they believe that technical feasibility must include considerations beyond just physical impossibility. Anything that would preclude or hinder implementation of the regulations should be included in a consideration of feasibility – whether technical, economic, or some other appropriate consideration. However, the commenter states that the EPA should be explicit that economics is to be considered in the feasibility analysis – as technical feasibility alone is insufficient.

Instead of EPA conflating technical feasibility and economic considerations, as it does in the Supplemental Proposal, the commenter (2326-AXPC) reports that the EPA in its final rule should transparently state that economic factors must be part of an affected facility’s ability to opt out of the regulatory requirement, in addition to whether installation and operation of the regulatory requirement is technically feasible and safe. The commenter therefore recommends that EPA adopt general standards for opting out of EPA’s performance standards or in instances where EPA has provided an opt out. Specifically, the commenter (2326-AXPC) suggests that an affected facility be able to opt out of the standard of performance if any of the following apply:

- The performance standard cannot reasonably be installed and operated at the affected/designated facility including due to technical feasibility, safety concerns, or physical impossibility;
- The cost of compliance with the performance standard would result in the affected/designated facility having a cost-effectiveness greater than \$5,540 per ton of VOCs or \$1,970 per ton of methane or the well is no longer able to economically operate; or
- The cost of compliance with the performance standard would be so great that it would result in the affected/designated facility no longer being able to economically operate.

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<sup>137</sup> 42 U.S.C. § 7411(a)(1).

In addition to the above, commenter (2326-AXPC) recommends EPA provide detailed information on what affected facilities can show to meet the requirements for opting out of a control requirement.

Response II-6-44: EPA disagrees that economic feasibility should be a factor in defining an “opt out” for the BSER requirements. As required by section 111(d) of the Clean Air Act, EPA considered the emission reduction, and the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements in determining BSER. The commenter cites BART, but those requirements are in response to a different statutory authority.

While the EPA does not consider many of the factors cited by the commenter to reflect economic viability, they do represent criteria that could be considered as part of a technical infeasibility determination. Examples of such criteria include landowner access; other local or state regulatory requirements; and other considerations that limit the ability to comply with the standard of performance. These criteria are not limited to physical impossibility.

Comment: Commenter (2326-AXPC) requests that for wells where the operator has designed and configured the separator to recover and sell or beneficially use associated gas, EPA remove the requirement to provide an infeasibility or safety justification for controlling associated gas when the primary means of disposition is temporarily unavailable. For these configurations, the commenter supports controlling the gas by using a permanent control device that meets the applicable control device requirements during periods when the primary means of disposition is unavailable. In the scenario where control is temporarily necessary, the operator would route the gas to the control device as soon as practicable. The commenter states that this is consistent with EPA’s acknowledgment in the preamble that the primary means of disposal may become temporarily unavailable for reasons outside the operator’s control and that EPA’s expectation is that the operator installs a permanent control device for these periods of temporary control. According to the commenter, requiring a certified justification in this scenario is overly burdensome with no corresponding environmental benefit.

The commenter (2326-AXPC, 3818-AXPC) proposes that EPA remove the requirement in 40 CFR 60.5377b(b)(1) and 60.5377c(b)(1) to provide a certified justification for controlling associated gas where the operator complies with 40 CFR 60.5377b/60.5377c (a)(1), (2), (3), or (4) during normal operations and temporarily controls associated gas when the primary method of disposition is unavailable.

Additionally, commenter (2326-AXPC) proposes eliminating the requirement to justify use of control in many circumstances. However, where a justification continues to be required, the commenter provides the following additional comments regarding economic viability. These comments are in addition to the comments they provide in their comment letter which addresses these considerations more generally. The commenter fully supports the concept of prioritizing the sale or beneficial use of associated gas as opposed to controls where markets exist and disposition into those markets is economically viable. However, they contend that the EPA must allow operators to control associated gas where no viable gas market exists, considering the commercial availability of a gas sales pipeline or other potential market and site economics to deliver gas to market. The commenter provides that this is consistent with the World Bank’s

“Zero Routine Flaring by 2030” initiative, in which some of the commenter’s members are participants. This global initiative encourages operators “to implement economically viable solutions to eliminate [routine] flaring as soon as possible.”<sup>138</sup> While a use may be technically feasible, they state that it may not be commercially viable, as discussed elsewhere in their comments.

Commenter (2326-AXPC) states that in addition to commercial availability/viability, a potential gas disposition method must be economically viable. For example, a remote well site operator could identify a pipeline with sufficient capacity, but the closest pipeline with sufficient takeaway capacity may be 100 miles away. And the cost to build, maintain, and operate the connecting pipeline may well exceed the total value of the gas that could be sold. Further, the additional infrastructure development is not without environmental impacts – *e.g.*, the impacts associated with the construction and installation of the pipeline. While it would be technically feasible to build this connecting pipeline, it is not an economically viable solution – *i.e.*, a cost-effective solution, as noted by EPA.<sup>139</sup> The commenter suggests that, to ignore economic viability would result in a rule that does not provide “achievable, cost-effective measures to significantly reduce methane and VOC emissions, consistent with the requirements of section 111 of the CAA.”

Commenter (2326-AXPC) believes that not only is it good policy to consider a control measure’s economic viability, but CAA section 111 requires it, as evidenced by its plain language and EPA’s many references to the Proposal’s cost-effectiveness. As noted in the regulatory impact analysis (RIA), which explicitly excludes any substantive analysis of the cost-effectiveness of EPA’s proposed oil well associated gas requirements, control of associated gas is appropriate where an operator does “not produce a large enough quantity of associated gas to offset the capital necessary to install” the infrastructure necessary to sell gas or use it in another beneficial way.<sup>140</sup> According to the commenter, inherent in this suggestion is the notion that economic considerations play a role in determining the feasibility of selling or using gas for a beneficial purpose.

Commenter (2326-AXPC, 3818-AXPC) proposes that EPA revise the proposed 40 CFR 60.5377b(b), and the corresponding EG OOOOc provision, as follows (underlined text indicates new text and struck out text indicates deleted text):

(b) If you demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section due to technical, economic, lack of commercial availability, or safety reasons in accordance with paragraphs (b)(1) through (3) of this section, you must route the associated gas to a control device that reduces methane and VOC emissions by at least 95.0 percent. The associated gas must be routed through a closed vent system that

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<sup>138</sup> The World Bank, [Global Initiative to Reduce Gas Flaring: “Zero Routine Flaring by 2030”, available at] <https://thedocs.worldbank.org/en/doc/a903b5e6456991faf3b5e079bba0391a-0400072021/related/ZRF-Initiative-text-list-map-103.pdf> (emphasis added).

<sup>139</sup> See 2022 RIA at 153.

<sup>140</sup> See 2022 RIA at 26, 153.

meets the requirements of §60.5411b(a) and (c) and the control device must meet the conditions specified in §60.5412b(a), (b) and (c).

(1) In order to demonstrate that it is not feasible to comply with paragraph (a)(1), (2), (3), or (4) of this section, you must provide a detailed analysis documenting and certifying the technical, economic, lack of commercial availability, or safety reasons for this infeasibility. The demonstration must address the technical, economic, lack of commercial availability, or safety infeasibility for all options identified in (a)(1), (2), (3), and (4) of this section. ~~With regard to compliance with paragraph (a)(3) of this section, another useful purpose that a purchased fuel or raw material would serve includes, but is not limited to, methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas.~~ Documentation of these demonstrations must be maintained in accordance with §60.5420b(c)(3)(ii). If the primary means of disposition of oil well associated gas is one of the options identified in (a)(1), (2), (3), and/or (4) of this section, you do not need to complete, certify, or document the detailed analysis in this section to utilize temporarily the option in §60.5377b(b).

(2) This demonstration must be certified by a professional engineer or another qualified individual with expertise in the uses of associated gas. The following certification, signed and dated by the qualified professional engineer or other qualified individual shall state: “I certify that the assessment of technical, economic, lack of commercial availability, and safety infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared pursuant to the requirements of §60.5377b(b)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

Response II-6-45: EPA agrees with this commenter, and the final rule allows the temporary flaring of associated gas when the gas cannot be routed to the sales line or used for the other primary beneficial purpose. See the response to II-6-6 and Section XI.F.2.f of the final rule preamble.

Comment: Commenter (2326-AXPC) suggests that if a justification is required for the temporary control of associated gas, EPA should allow operators to develop a gas capture plan for the similarly simulated oil wells with associated gas. The commenter proposes eliminating the requirement to justify use of control in many circumstances.

However, where a justification continues to be required, the commenter provides the following additional comments regarding such justifications. EPA proposes that operators prioritize the sale, use, or injection of crude oil well associated gas over use of a control device to reduce emissions, and where an operator must control associated gas emissions because it is technically infeasible or unsafe to sell, use, or inject associated gas, it must justify and certify why. This requirement applies to “each oil well with associated gas at a well affected [or “designated”

under EG OOOOc] facility,”<sup>141</sup> meaning the certification requirement would apply on a well-by-well basis. If the exemption from justification proposed by the commenter is not adopted, this may require hundreds or thousands of certifications that would be unnecessarily onerous where similarly situated oil wells must control associated gas emissions to comply with the oil well associated gas provisions, even where control is limited to temporary situations.

Commenter (2326-AXPC) states that because regional circumstances often dictate associated gas disposition, an operator may comply with the associated gas standards in the same manner for all or many wells in a region, and where the primary means of compliance is unavailable, the operator is likely to use the same alternative method(s) of compliance for all similarly situated wells. For example, where gas pipeline takeaway is readily available in a region, the operator will dispose of natural gas produced from all wells in the region into the pipeline and route gas to control when the pipeline is temporarily unavailable. For these similarly situated wells, it would be most efficient for the operator to use one document that covers all wells to identify the primary compliance approach – *e.g.*, pipeline injection – and the technical infeasibility or safety justification for controlling gas when the primary compliance approach is unavailable.

Commenter (2326-AXPC) proposes that, as an alternative to a well-by-well certification requirement, operators may develop a system-wide gas capture plan that would cover all similarly situated oil wells – *e.g.*, oil wells that share a common gas gathering system or other appropriately representative grouping. Under this plan, operators would identify the primary means of complying with §§60.5377b(a) or 60.5391c(a), as applicable, and where the operator must control associated gas because the primary means of associated gas disposition is technically infeasible or unsafe, the operator would provide a commonly applicable justification. For example, as EPA identifies in the preamble, interruptions to the gas gathering system may affect an operator’s ability to sell gas. In these instances where operators dispose of associated gas via pipeline, operators are unlikely to have the infrastructure available to use the gas for another purpose or to reinject the gas, leaving control as the only other feasible option. In response to the commenters that identified this potential issue, EPA proposes that operators “provide a technical or safety demonstration in their annual report and install and operate a control device that achieves the required reduction during these temporary periods.” The same logic would apply for operators that use gas for a beneficial purpose or re-inject gas. Like with gas sent to pipeline, a beneficial use or re-injection may become unavailable without notice, and the operator must instead control the gas.

Commenter (2326-AXPC) states that applying the gas capture plan approach, the operator would identify pipeline injection as the primary compliance method for all wells covered by the gas capture plan, and when pipeline disposition is technically infeasible – *e.g.*, due to capacity constraints or pipeline downtime, the operator would comply with 40 CFR 60.5377b(b) by controlling the associated gas with a control device meeting all applicable NSPS OOOOb requirements. The commenter adds that an operator would provide the justification of technical infeasibility that is commonly applicable to all wells covered by the gas capture plan, and no well-by-well justification would be required. Under this gas capture plan approach, operators would maintain records of compliance with the gas capture plan and report compliance in a similar manner as currently proposed. Using the example above, if the operator vents gas rather

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<sup>141</sup> See Proposed 40 C.F.R. §§60.5377b(a), .5391c(a).

than controls it, the operator would maintain records of this event and report its occurrence in the annual report. Similarly, operators that control associated gas during a reporting period would provide a copy of the gas capture plan's justification applicable to the well(s) that required associated gas control during the reporting period.

Just as with the proposed requirement to consider changes that would impact an operator's ability to comply with the requirements to sell, use, or re-inject associated gas, the commenter (2326-AXPC) proposes that operators that routinely or periodically control associated gas under a gas capture plan would consider and report on any changes in the region that impact the operator's ability to comply with the requirement to sell, use, or re-inject associated gas.

To summarize, commenter (2326-AXPC) requests that EPA add language to the oil well associated gas provisions that would allow operators to develop a gas capture plan for similarly situated oil wells with associated gas. The commenter recommends that operators must develop and maintain records of the gas capture plan, which must identify the primary method(s) of gas disposition, and where control of associated gas is necessary on a permanent or temporary basis, the operator must justify the technical infeasibility and/or safety justification for controlling the gas, with such justification to apply to all wells covered by the gas capture plan. The commenter adds that operators using a gas capture plan would maintain records and report under a framework similar to the December 2022 supplemental proposal's recordkeeping and reporting requirements.

Response II-6-46: EPA agrees with this commenter, and the final rule allows the temporary flaring of associated gas when the gas cannot be routed to the sales line or used for the other primary beneficial purpose. See the response to II-6-6 and Section XI.F.2.f of the final rule preamble.

Comment: Commenter (2294-OOGA) expresses that, under the December 2022 supplemental proposal, associated gas cannot be routed to a flare or other combustion device unless the owner or operator demonstrates that each of the four compliance options are infeasible due to technical or safety reasons, and that demonstration is approved by a certified professional engineer. The commenter notes that this is a significant change from the November 2021 proposed rule that places additional burden on operators which may be unworkable as a practical matter.

Response II-6-47: EPA acknowledges the difference in the November 2021 proposal and the December 2022 supplemental proposal, as discussed in the supplemental proposal preamble. EPA disagrees that the final rule is unworkable as a practical matter and maintains that it provides reasonable requirements with provisions that allow for situations when the complying with the primary standard is technically infeasible.

Comment: Commenter (2403-The Petroleum Alliance of Oklahoma (PAO)) contends that, for those situations where the operator is connected to a sales line and there are instances where the gas needs to be routed intermittently to a control device for equipment maintenance, repairs, emergencies or other similar situations, this type of flaring should not have to undergo repeated onerous infeasibility determinations and detailed recordkeeping requirements. A one-time feasibility determination should suffice. The commenter suggests that the requirement to have a



certified professional engineer conduct the feasibility analysis is excessive as well. In-house engineers with the knowledge, experience and understanding of the site conditions should be allowed to conduct the technical infeasibility demonstration. Also, the commenter states that the EPA should recognize the characteristics and limitations of low producing, marginal wells. The production of these wells is declining. Repeated, onerous technical infeasibility analysis, and detailed recordkeeping should be eliminated in the final rule.

Response II-6-48: EPA agrees with this commenter, and the final rule allows the temporary flaring of associated gas when the gas cannot be routed to the sales line or used for the other primary beneficial purpose. See the response to II-6-6 and Section XI.F.2.f of the final rule preamble. EPA disagrees however, that repeated infeasibility determinations should be eliminated. In fact, if an option becomes available where an owner or operator is able to sell or utilize the associated gas for a beneficial purpose, that may increase the economic viability of the well and extend its life.

Comment: Commenter (2247-Ohio Environmental Protection Agency (OHEPA)) states that, under paragraph (b) of 40 CFR 60.5391c (What GHG standards apply to oil wells with associated gas at well designated facilities?) [also applies to parallel provisions under NSPS OOOOb], does “feasible” mean just technically feasible, economically feasible or both? If economic feasibility needs to be assessed, what factors or thresholds should be considered?

Response II-6-49: EPA believes that it has been quite clear that feasibility is based on technical feasibility and not economic feasibility.

Comment: Commenter (2348-Energy Workforce & Technology Council (EWTC)) suggests that a “qualified individual” for production systems should have a background in process and/or petroleum engineering, with experience operating and/or starting up production facilities in the field. Qualified persons for other activities, such as drilling and completions, would require expertise and field experience in these respective areas.

Response II-6-50: The final rule allows a technical infeasibility determination to be certified by either a professional engineer or another qualified individual with expertise in the uses of associated gas. The type of professional described by the commenter would qualify as such an individual.

Comment: Commenters (2028-WMCG, 2039-CPLV) suggest that rather than applying for an exception which increases emissions, companies could instead apply for assistance in avoiding concentrated, high emission pollution incidents. By way of example, the commenters state that “blowdowns” are a significant source of air pollution in Pennsylvania and believes their frequency is routinely underestimated by the Pennsylvania Department of Environmental Protection (DEP) in air pollution permits. The commenters point out that most industrial rules are focused on annual pollution levels at a specific facility, but concentrated pollution events like blowdowns result in acute exposures to air pollution that increase the likelihood of respiratory damage or other health effects. The commenters provide that EPA has advocated for equipment that would reduce air pollution from blowdowns since 2012 and they believe EPA must take an

active role in the application of these pollution reduction technologies, specifically with the \$1.55 billion allocated to EPA in the methane emissions reduction program (MERP).

Response II-6-51: This comment is outside the scope of this regulatory action.

#### 6.2.4.4 Support Approaches Taken by Colorado and New Mexico for Temporary Flaring

Comment: Commenter (2433-EDF et al) recommends the replacement of the “technical infeasibility” exemption with clearly delineated circumstances for temporary flaring. Rather than include a technical infeasibility exemption, the commenter recommends that EPA require oil wells to capture associated gas by utilizing one of the four recovery options, except in specific, narrowly defined circumstances when a well may be permitted to flare on a temporary basis. In doing so, EPA can follow the approach taken by Colorado and New Mexico to address routine flaring. Both states prohibit venting or flaring other than in enumerated exceptional situations. EPA can apply these exemptions nationally because “[t]he types of reservoir traps, reservoir drives, subsurface geology, structures, production technologies, infrastructure buildouts, availability of services and supplies are all very similar across producing areas.”<sup>142</sup> A time-limited or otherwise narrow exemption to utilizing one of EPA’s approved gas recovery options may be justified in the following circumstances, each discussed in more detail below: upset conditions; pipeline, equipment, or facilities commissioning; initial production where gas does not meet pipeline specifications and where an operator is connected to a gathering line; active and required maintenance; production evaluation and production tests; Bradenhead monitoring; and packer leakage tests.<sup>143</sup>

To assist with compliance and enforcement, the commenter (2433-EDF et al) suggests that EPA require that operators maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each event it seeks to justify under one of the exemptions.<sup>144</sup> Below, the commenter discusses circumstances where EPA may consider exemptions from its capture requirements in which flaring is authorized.

Commenter (2433-EDF et al) suggests that capture may be technically infeasible or unsafe for a limited amount of time during upset conditions, which are emergency circumstances outside of the control of an operator that can interrupt its ability to comply with the proposed standard. An example of an upset condition is a temporary, unplanned loss of connection to, or ability to route gas to, a gathering system. The commenter notes that the EPA has determined that interruptions of an operator’s ability to route gas to a gathering system constitute a technical or safety reasons that can justify flaring. It is critical that EPA permit only temporary flaring during these circumstances and establish clear time limitations during which it may be permitted. Both Colorado and New Mexico allow operators to flare or vent gas for a short period of time during upset conditions or emergencies, including temporary unavailability of access to a gathering line. The commenter states that the Colorado rules provide a concise, clear definition of this circumstance, while also limiting the length of time an operator may flare or vent during such circumstances. Colorado’s definition of an “Upset Condition” is “a sudden unavoidable failure,

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<sup>142</sup> Expert Report of Thomas Alexander, *supra* note 435, at 3.

<sup>143</sup> *Id.* at 4–6.

<sup>144</sup> See e.g., 2 Colo. Code Regs. §404-1-903.d.(2) (2023).

breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction.”<sup>145</sup> Notably, per the Statement of Basis and Purpose for the rule, this definition does not include “an operator’s negligence, failure to install appropriate equipment, or failure to perform scheduled maintenance.”<sup>146</sup>

Furthermore, commenter (2433-EDF et al) points out that Colorado limits venting and flaring during upset conditions to a period necessary to address the upset, not to exceed 24 cumulative hours, and requires operators to maintain records of the date, cause, estimated volume of gas flared or vented, and duration of each upset condition.<sup>147</sup> Per the Statement of Basis and Purpose for the rule, Colorado’s definition of an upset condition also include sudden lack of pipeline capacity.<sup>148</sup> Accordingly, Colorado allows operators to vent or flare associated gas in the event that unplanned disruptions to a gathering system interrupt the ability of an operator to route associated gas to a sales line, but only up to 24 cumulative hours.

Commenter (2433-EDF et al) states that New Mexico similarly allows for temporary venting or flaring during an emergency. An emergency means “a temporary, infrequent, and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health, or the environment” other than in certain exceptions.<sup>149</sup> One such exception is “venting or flaring of natural gas for more than eight hours after notification that is caused by an emergency, an unscheduled maintenance, or a malfunction of a natural gas gathering system.”<sup>150</sup> In other words, an upstream operator may vent or flare during a temporary, infrequent, and unavoidable event involving loss of connection to a sales line provided the midstream operator notifies the producer of the disruption to the operator of the sales line. However, an upstream operator cannot vent longer than 8 hours in this circumstance.<sup>151</sup>

Commenter (2433-EDF et al) recommends EPA limit flaring or venting during an upset condition to not more than 24 cumulative hours, in line with the Colorado rules. This would apply in those instances where a disruption to a gathering system or other event causes an interruption to an operator’s ability to route the gas to a sales line. Prudent operators should be prepared to recover gas in the event of sudden loss of takeaway capacity.<sup>152</sup> Specifically, while short-term flaring may be necessary to allow the operator to make alternative arrangements for the disposition of associated gas, prudent operators can quickly deploy alternative uses of the gas such as onsite use, compression for CNG, or injection.<sup>153</sup> Because of this the commenter does

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<sup>145</sup> 2 Colo. Code Regs. §404-1-100-21 (2023).

<sup>146</sup> Colo. Oil & Gas Conservation Comm., Statement of Basis, Specific Statutory Authority, and Purpose: New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 800/900/1200 Mission Change Rulemaking at 76, (Dkt. No. 200600115), <https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/800-900-1200MissionChangeDraftSBP.pdf> [hereinafter Colo. 800/900/1200 SBP].

<sup>147</sup> 2 Colo. Code Regs. § 404-1-903.(d)(1)(A) (2023).

<sup>148</sup> Colo. 800/900/1200 SBP, *supra* note 450, at 76.

<sup>149</sup> N. M. Code R. §19.15.27.7.H (2023).

<sup>150</sup> *Id.* §19.15.27.7.H.(4).

<sup>151</sup> *Id.* §19.15.27.8.E.(8).

<sup>152</sup> Expert report of Thomas Alexander, *supra* note 435, at 4.

<sup>153</sup> *Id.*

not believe EPA should include a separate exemption for loss of takeaway capacity that would permit flaring or venting in excess of 24 hours.

Response II-6-52: EPA considered these state rules in the development of the final rule requirements rule requirements for temporary flaring and venting.

Comment: Commenter (2433-EDF et al) discusses circumstances where EPA may consider exemptions from its capture requirements in which flaring is authorized. One circumstance that may give rise to an operator's need to flare on a temporary basis is the commissioning of pipelines, equipment, or facilities.<sup>154</sup> The commenter provides that New Mexico allows operators to flare temporarily during these circumstances,<sup>155</sup> and even then "only for as long as necessary to purge introduced impurities."<sup>156</sup> An operator may need to flare temporarily when it is first connecting to a pipeline that has just been constructed if the pipeline was cleaned out with substances that the midstream operator does not want in the gas.<sup>157</sup> With proper coordination between midstream and downstream operations, operators can substantially mitigate any lost production of oil and avoid unnecessary flaring of associated gas.<sup>158</sup> If carefully applied, the commenter contends that this limited exemption will not give rise to significant emissions; "flaring during this exemption will often be of very short duration," since it does not take long to "clear impurities from equipment, facilities or pipelines."<sup>159</sup>

Commenter (2433-EDF et al) also suggests that operators may also need to flare temporarily where an operator is connected to a sales line, but natural gas does not meet pipeline specifications and the other three gas recovery options are also unavailable.<sup>160</sup> This occurs where impurities such as oxygen or nitrogen are present in the associated gas and thus the gas cannot safely be sent to the sales line.<sup>161</sup> New Mexico requires the operator take specific steps to limit flaring during this circumstance. Operators must analyze gas samples twice a week to determine if pipeline specifications have been achieved, and must route gas into gathering pipelines when pipeline specifications are met.<sup>162</sup> Operators must also provide pipeline specifications and gas analyses to the agency upon request.<sup>163</sup> The amount of time an operator may need to flare in order to clean up associated gas prior to routing to sales should be short, with the specific timeframe varying depending on the reservoir characteristics and composition of the hydraulic fracturing fluid. On average, an operator may need to flare for as little as two days to a week.<sup>164</sup> Requiring an operator to take frequent samples of gas composition is imperative so that it can begin routing gas to sales as quickly as possible once impurities have been removed. The New

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<sup>154</sup> Expert report of Thomas Alexander, supra note 435, at 5.

<sup>155</sup> N.M. Code R. § 19.15.27.8.D.(4)(m) (2023).

<sup>156</sup> Id. § 19.15.27.8.D.(4)(m).

<sup>157</sup> Expert report of Thomas Alexander, supra note 435, at 5.

<sup>158</sup> Id.

<sup>159</sup> Id.

<sup>160</sup> Id. at 6-7; N.M. Code R. § 19.15.27.8.D.(4)(l) (2023).

<sup>161</sup> Expert report of Thomas Alexander, supra note 435, at 6-7.

<sup>162</sup> N.M. Code R. § 19.15.27.8.D.(4)(l) (2023).

<sup>163</sup> Id.

<sup>164</sup> Expert report of Thomas Alexander, supra note 435, at 5.

Mexico requirement that operators sample twice a week is quite reasonable, and prudent operators will likely sample more frequently since there is a profit incentive to doing so.<sup>165</sup>

Commenter (2433-EDF) states that both Colorado and New Mexico allow for temporary venting and flaring during active and required maintenance activities. The commenter explains that Colorado specifies that maintenance must both be active and required, clarifying that "while venting can be permitted while the maintenance activity is ongoing (for example, while personnel are on-site and performing the maintenance), venting during periods between discovery of the need for maintenance and the performance of the maintenance remains prohibited."<sup>166</sup> Colorado also requires operators to use best management practices to minimize venting during maintenance and repair activity, and Colorado is currently phasing in requirements that midstream operators capture hydrocarbons from blowdowns of compressors and other equipment at compressor stations and gas processing plants<sup>167</sup> - once fully phased in, Colorado midstream operators may no longer flare gas from depressurization of equipment for routine maintenance. New Mexico similarly allows venting or flaring during repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance.<sup>168</sup> The commenter recommends that EPA allow flaring during active and required maintenance activities, which includes blowing down and depressurizing production equipment.<sup>169</sup>

Commenter (2433-EDF et al) adds that Colorado and New Mexico both allow for temporary flaring during production tests and production evaluations. Colorado defines a "Productivity Test" to mean "a test for determination of a reservoir's ability to produce economic quantities of oil or gas."<sup>170</sup> Colorado defines a "production evaluation" as "an evaluation of production potential for determination of requirements for infrastructure capacity and equipment sizing."<sup>171</sup> Colorado allows venting or flaring during both events, but only subject to pre-approval. If the operator has obtained approval, the rules permit venting or flaring for a period not to exceed 60 days.<sup>172</sup> New Mexico limits venting or flaring during a production test for a period not to exceed 24 hours absent approval for a longer test period.<sup>173</sup> The commenter recommends EPA allow flaring during production and evaluation tests but limit the duration of these emissions events to 24 hours, as New Mexico has done, unless the operator obtains pre-approval to flare for a longer period of time. There may be instances, based on reservoir characteristics and the amount of knowledge an operator has about the reservoir's productivity, that an operator may need to flare for longer than 24 hours,<sup>174</sup> but in no event should flaring during this exemption exceed 60 days.<sup>175</sup>

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<sup>165</sup> Id.

<sup>166</sup> Colo. 800/900/1200 SBP, *supra* note 450, at 84.

<sup>167</sup> 5 Colo. Code Regs. 1001-9-D-II.H.

<sup>168</sup> N.M. Code R. § 19.15.27.8.

<sup>169</sup> Expert report of Thomas Alexander, *supra* note 435, at 5–6.

<sup>170</sup> 2 Colo. Code Regs. § 404-1-100-15.

<sup>171</sup> 2 Colo. Code Regs. § 404-1-100-14.

<sup>172</sup> 2 Colo. Code Regs. § 404-1-903.d.(1)(C).

<sup>173</sup> N.M. Code R. § 19.15.27.8.D.(4)(k) (2023).

<sup>174</sup> Expert report of Thomas Alexander, *supra* note 435.

<sup>175</sup> Datu Research, *supra* note 292, at 8.

Commenter (2433-EDF et al) also acknowledges that venting may be necessary for safety as previously acknowledged.<sup>176</sup> In addition, operators may need to vent for a very brief period during downhole monitoring activities, namely when monitoring the downhole pressure during bradenhead monitoring and packer leakage tests. The commenter reports that both Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.<sup>177</sup> Colorado limits bradenhead monitoring to 30 minutes.<sup>178</sup> New Mexico also allows operators to flare or vent during packer leakage tests.<sup>179, 180</sup>

Response II-6-53: EPA considered these state rules in the development of the final rule requirements rule requirements for temporary flaring and venting.

Comment: Commenter (2433-EDF et al) suggests that EPA should require pre-approval of requests to flare based on claims of technical infeasibility. Doing so would enhance oversight and reduce abuse that could otherwise occur without pre-approval.

Commenter (2433-EDF et al) states that in Colorado, operators may flare gas during completion operations with specific written approval of the operator's gas capture plan.<sup>181</sup> Alternatively, the operator may submit a form which explains why flaring is necessary to complete the well and will minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources; estimates the anticipated flaring volume and duration; and explains its plan to connect the facility to a gathering line or otherwise utilize the gas in the future. The operator's plan may be approved, through a form requesting permission to flare during completion, if it is determined that the flaring is necessary to complete the well and the operator will minimize adverse impacts to public health, safety, welfare, the environment, and wildlife resources.<sup>182</sup> In addition, Colorado requires pre-approval and documentation supporting the request for flaring in the event that an operator loses access to a gathering line.

In either instance, commenter (2433-EDF et al) suggests that EPA require public disclosure of flaring activities. Colorado requires notification of planned flaring, no later than two hours before flaring, as well as subsequent (and no later than 12 hour) notice of flaring due to upset conditions.<sup>183</sup> New Mexico requires notice of venting or flaring exceeding 50 Mcf resulting from an emergency or malfunction, or that lasts eight hours or more within a 24-hour period.<sup>184</sup>

Finally, commenter (2433-EDF et al) recommends additional recordkeeping and reporting requirements to bolster the enforceability of the demonstration and prevent abuse of the

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<sup>176</sup> 2022 Joint Environmental Comments, supra note 1, at 181 (acknowledging that venting may occur during emergencies).

<sup>177</sup> N.M. Code R. § 19.15.27.8.D.(4).(i).

<sup>178</sup> Colo. 800/900/1200 SBP, supra note 450, at 86.

<sup>179</sup> N.M. Code R. § 19.15.27.8.D.(4).(j).

<sup>180</sup> Expert report of Thomas Alexander, supra note 435, at 6.

<sup>181</sup> 2 Colo. Code Regs. § 404-1-903.C.(3).

<sup>182</sup> Id.

<sup>183</sup> 2 Colo. Code Regs. § 404-1-903.a.(1),(2).

<sup>184</sup> N.M. Code R. § 19.15.27.8.G.(1) (2023).

exemption. These recommendations are based on requirements in Colorado<sup>185</sup> and New Mexico.<sup>186</sup> Specifically, the commenter recommends that operators' initial and annual demonstrations include an estimate or measurement of the volume and content of vented or flared gas. This information should also be provided in the operator's annual report. As Colorado regulators have found, the commenter states that requiring records of the estimated duration and time of flaring helps prevent abuse and enhances enforcement.<sup>187</sup> The commenter adds that flaring data should also be publicly disclosed.

Response II-6-54: EPA concluded that pre-approval of flaring activity provides an excessive burden on both the owners and operators and the Agency, so the final rule does not include such provisions. The final rule does include specific circumstances and time frames when temporary flaring is allowed. Specifically, these are:

- For equal to or less than 24 hours during a deviation caused by malfunction causing the need to flare.
- For equal to or less than 24 hours during repair, maintenance including blow downs, a bradenhead test, a packer leakage test, a production test, or commissioning.
- For (a)(1) and (b)(1), through the duration of a temporary interruption in service from the gathering or pipeline system, or 30 days, whichever is less.
- For 72 hours from the time that the associated gas does not meet pipeline specification, or until the associated gas meets pipeline specifications, whichever is less.

These provisions are at §60.5377b((d)(1) through (4) and §60.5391c((c)(1) through (4) of EG OOOOc.

Comment: Commenter (2428-CO-LGC) asserts that the technical infeasibility exemption places a significant compliance monitoring burden on EPA, or states with delegated air quality programs such as Colorado. While an operator's certified demonstration must be signed and certified as to its truth, accuracy and completeness, there is no requirement that EPA review and approve this demonstration prior to an operator flaring. Rather, operators must retain records of the certified demonstration and provide it to EPA as part of annual reporting. According to the commenter, this raises the possibility that flaring will occur in the absence of a truthful, accurate, complete, or otherwise adequate demonstration. For EPA to identify any problems with the certified demonstration, EPA must review the operator's certified demonstration – this review will necessarily occur after an operator has flared, and even routinely flared for potentially a considerable amount of time. The commenter states that this opens the door to extended periods of flaring and pollution in violation of the rules.

Response II-6-55: The points made by the commenter appear to be somewhat contradictory. They are expressing concern over the burden placed on EPA and delegated agencies with the proposed infeasibility structure while also suggesting approval of each infeasibility determination prior to flaring being allowed, which would increase the burden. EPA believes that

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<sup>185</sup> 2 Colo. Code Regs. § 404-1-903.d.(2) (2023).

<sup>186</sup> N.M. Code R. § 19.15.27.8.G.(2) (2023).

<sup>187</sup> Colo. 800/900/1200 SBP, *supra* note 450, at 78.

the severe penalties that could be imposed on both the owner operator and the engineer that signs the certification are a sufficient deterrent for fraudulent infeasibility claims.

#### 6.2.4.5 Control Device Requirements (Inclusive of Flares)

Comment: Commenter (2433-EDF et al) states that in situations where flaring occurs, operators would be required to route associated gas through a closed vent system that meets the requirements proposed at 40 CFR 60.5411b(a) and (c) to a control device that reduces emissions by at least 95 percent and meets the conditions of 40 CFR 60.5412b(a)-(c).<sup>188</sup> The commenter strongly supports these requirements, which the commenter believes are critical for addressing the commonly-observed problems from inefficient, malfunctioning, and unlit flares. Below, the commenter explains why EPA's proposed control device requirements are necessary and suggest additional improvements.

Commenter (2433-EDF) states that the problem of unlit and malfunctioning flares is a well-documented and prevalent issue that is a significant source of methane emissions. EDF scientists have assessed flare performance in the Permian Basin with a series of helicopter-based infrared camera surveys.<sup>189</sup> Based on over 1,000 flare observations, approximately 5 percent of large flares are unlit and venting gas at any given time, and another 5% have visible slip of methane or other hydrocarbons—meaning the flare is only partially combusting the methane and the rest is escaping to the atmosphere.<sup>190</sup> On-the-ground flare combustion efficiency is thus much worse than EPA has assumed and what regulatory standards require.<sup>191</sup> Flares are consequently one of the largest sources of methane in the Permian Basin, and the latest surveys have found even worse performance among smaller, intermittent flares.<sup>192</sup>

Commenter (2433-EDF) states that other recent studies have confirmed that unlit or malfunctioning flares are one of the largest sources of methane emissions.<sup>193</sup> A study consisting of in situ measurements of lit flares found an average combustion efficiency of 91 percent for flares in the Permian Basin.<sup>194</sup> When accounting for unlit flares, the study that found average efficiencies of flares across major production basins range between 85 percent and 93 percent.<sup>195</sup> Multi-basin research has identified unlit flares across the entire country, and a Permian Basin study using flights conducted in 2020 found 5 percent of all active flares were unlit.<sup>196</sup>

Commenter (2433-EDF) states that improved control device performance is feasible and already required by leading states. For example, the commenter reports that Colorado requires operators

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<sup>188</sup> Proposed 40 CFR 60.5377b.

<sup>189</sup> Permian MAP, Flaring Aerial Survey Results (2021), <https://www.permianmap.org/flaring-emissions/> (last visited Feb. 13, 2023).

<sup>190</sup> Id.

<sup>191</sup> Id.

<sup>192</sup> Id.

<sup>193</sup> See, e.g., Daniel H. Cusworth et al., Intermittency of Large Methane Emitters in the Permian Basin, 8 Env't Sci. Tech. Letters 567 (2021), <https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173>.

<sup>194</sup> Plant et al., supra note 174.

<sup>195</sup> Id. at Table 1.

<sup>196</sup> David R. Lyon et al., Concurrent Variation in Oil and Gas Methane Emissions and Oil Price During the COVID-19 Pandemic, 21 Atmos. Chem. Phys. 6605 (2021), <https://acp.copernicus.org/articles/21/6605/2021/>.



to use an enclosed combustion device with a design destruction efficiency of at least 98 percent for hydrocarbons.<sup>197</sup> And New Mexico requires control devices used to abate well completion emissions either meet a 95 percent or 98 percent destruction efficiency. Specifically, if an operator uses an enclosed combustion device or thermal oxidizer, the destruction efficiency must be at least 98 percent for hydrocarbons.<sup>198</sup> If operators use a different type of control device (e.g., a flare), it must have a control efficiency of at least 95 percent for hydrocarbons.<sup>199</sup>

Commenter (2433-EDF) strongly supports EPA's improved control device requirements, which the commenter believes will help address the serious problems posed by unlit and malfunctioning flares. By using the pilot and flow monitoring devices in combination with one another, the commenter states that operators will be able to measure the amounts of combusted and vented gas during periods in which the flare is unlit. In 2021, only 20 percent of flare units across in the Permian basin across all industry segments had continuous flow monitoring according to the Greenhouse Gas Reporting Program (GHGRP).<sup>200</sup> The proposed requirements will improve the accuracy and reliability of the reported data, while enabling operators to timely address flare malfunctions. The commenter contends that the addition of continuous monitoring requirements of the pilot light and gas flow rate are significant and low-cost improvements that will help ensure proper combustion and will also support EPA improving the reporting of unlit flare emissions.

Commenter (2433-EDF) points out the two exemptions to the flow rate requirement that the EPA has provided. The first is available if an engineering assessment of the sources vented to the flare indicates that the maximum gas flow rates would not exceed the maximum flare tip velocity. The second is available if a backpressure preventer is installed which is set to operate at or above the minimum inlet gas flow rate. While ensuring gas flow rates are below the maximum flare tip velocity will help maintain efficient combustion, the commenter believes that the engineering assessment and subsequent exemption from the flow monitoring requirement hampers EPA's ability to quantify and address emissions from unlit flares. The commenter states that only when both the pilot light and gas flow of the flare stack are continuously monitored can operators accurately report the amount of gas emitted while a flare is unlit. Given the high rate of unlit flares in the Permian,<sup>201</sup> Eagle Ford, and Bakken formations,<sup>202</sup> flow monitoring of flares is necessary in all cases. The commenter urges EPA to ensure that in all circumstances, both continuous monitoring of the pilot light and the flow rate occur, which are necessary to enabling an accurate and empirical assessment of flared gas emissions and an understanding whether flares are unlit. The commenter believes there should be no exemptions from these two requirements given the high rate of observed unlit flares.

Commenter (2433-EDF) also supports the requirements for no visible emissions and monthly monitoring using Method 22. The commenter adds that EPA could also consider alternative

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<sup>197</sup> 2 Colo. Code Regs. § 404-1-903, R. 903.d.(5) (2023).

<sup>198</sup> N.M. Code R. § 20.5.20.127.B.(1)(2) (2023).

<sup>199</sup> Id.

<sup>200</sup> U.S. Env't Protection Agency, Greenhouse Gas Reporting Program Flare Unit Data, <https://www.epa.gov/ghgreporting/data-sets> (last visited Feb. 13, 2023).

<sup>201</sup> Lyon et al., Concurrent Variation, *supra* note 527.

<sup>202</sup> Plant et al., *supra* note 174.

monitoring technologies and methods that would achieve equivalent or superior results. The commenter believes this monitoring requirement, paired with the control device monitoring the commenter recommends during leak detection and repair (LDAR) surveys described in Section IV.B of their comment letter, will help ensure that unlit and malfunctioning flares are quickly detected and returned to compliant operating status. The commenter contends that Method 22 monitoring can be conducted at the same time as LDAR surveys and therefore poses little-to-no additional burden on operators.

Response II-6-56: EPA acknowledges the support of the commenters, as well as the concerns related to flaring. The final rule only allows routine flaring of associated gas in limited circumstances, so it will effectively reduce the amount of flaring in the US. The final rule also includes enhanced compliance requirements to ensure that flares are operating properly. This is discussed in more detail in Section 17.2 of this document.

Comment: Commenter (2218-TCEQ) supports the continued use of 40 CFR 60.18 requirements and monitoring to demonstrate 98 percent destruction efficiency for flares and vendor information for other control devices. The commenter's authorization mechanisms for flares closely match 40 CFR 60.18 requirements and allow for the use of an automatic pilot. The commenter recommends that the use of an automatic pilot continues to be an option for non-pressure-assisted flares. Also, the commenter notes that many remote sites only have field gas as an option to use in a continuous pilot. Field gas may have a high concentration of hydrogen sulfide, so using a continuous pilot in these situations may lead to increased emissions of hydrogen sulfide and sulfur dioxide. In addition, the commenter states that the remoteness of and lack of electricity for some sites may present logistical barriers complicating or preventing the implementation of continuous monitoring. The commenter supports the use of temporary control devices for situations when associated gas could not be routed to a sales line or used for other beneficial purposes. The commenter explains that some sites may have permanent control devices for these scenarios; however, temporary controls can be used to minimize emissions during planned maintenance, startup, and shutdown activities. Emissions from these temporary controls are permitted as an alternate operating scenario, as a part of normal operations.

Response II-6-57: The final rule includes enhanced compliance provisions to ensure that flares meet the requirements in §60.18. This applies both to flares used to routinely reduce associated gas emissions, as well as flares that are used temporarily when the primary option (e.g., routing to sales or other beneficial use) is unavailable. However, as final NSPS OOOOb rule addresses emissions of VOC and methane, and the final presumptive standards in EG OOOOc address methane emissions, emissions of hydrogen sulfide and sulfur dioxide created in the flare are not covered.

Comment: Commenter (2237-NDIC) states that for control devices used to comply with emissions standards at well facilities in cases where associated gas is not otherwise sold or routed to a beneficial use, the supplemental proposal requires a full Method 25A test for the control device to determine the 95 percent methane reduction requirement in 40 CFR 60.5412c(a)(1)(i). The commenter has previously commented that due to issues with sales line access that control devices are required by state law at sites even if a sales line is available, in

case of situations where access is cutoff due to pipeline maintenance/emergencies, pressure issues, or lack of takeaway capacity within the pipeline itself.

Commenter (2237-NDIC) states that North Dakota state law requires that organic compounds gases and vapors be burned by a flare or an equally effective control device (except when from an emergency vapor blowdown system or emergency relief system), so essentially every well site that could emit "organic compounds gases and vapors" (North Dakota Administrative Code Chapter 33.1-15-07-02) has a flare of some type.

Commenter (2237-NDIC) states that is concerned that the testing requirements would put an undue burden on operators operating what is essentially a backup device to safely dispose of the gas and prevent venting during such upsets and other temporary disruptions. The commenter requests that control devices used temporarily when associated gas cannot be sold or otherwise routed for beneficial use be exempted from the operational and performance testing requirements.

Response II-6-58: Based on comments received and information available to the Agency, EPA clearly understands that in situations where the associated gas is routed to a sales line or used for another beneficial purpose, situations occur that will cause the primary option of using the associated gas to be unavailable. As discussed in response to many other comments in this section, the final rule allows the associated gas to be routed to a flare or control device in these temporary situations. However, it is evident from the comments that this is not a rare or uncommon situation. Given the potential frequency of such occurrences, and the potential significant level of cumulative emissions, EPA concluded that is necessary to ensure that the flare or control device to which the associated gas is temporarily routed is operating properly and is achieving the desired reduction in emissions. Therefore, no change was in the final rule in response to this comment.

Comment: For wells where associated gas from the separator is designed and configured to be recovered, commenter (2428-API) supports simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, the commenter supports flaring the gas by using a permanent or temporary control device that achieves 95 percent efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable, without the need for a technical infeasibility demonstration.

Response II-6-59: The final rule is consistent with the concepts suggested by the commenter. See Response II-6-6 in this Chapter and Section XI.F.2.f of the final rule preamble.

Comment: Commenter (2360-Devon Energy) encourages EPA to distinguish between “routine” and “non-routine” flaring events. While the commenter believes it is appropriate to restrict the routine flaring of associated gas, if the ability exists to provide a demonstration of infeasibility for unique circumstances, non-routine flaring may occur due to any number of extenuating circumstances beyond the reasonable control of the operator. The commenter encourages EPA to

consult with operators to properly characterize or define “routine” and “non-routine” flaring of associated gas in the final rule and allow for more streamlined notifications in situations where “non-routine” flaring may occur.

Commenter (2409-BP America Incorporated (BP)) urges EPA to consider defining routine and non-routine flaring to account for circumstances where flaring devices are being used to combust emissions that would otherwise be vented, particularly where EPA seeks to limit the scope of safety flaring for non-routine purposes by narrowly defining permissible scenarios for safety flaring.

Commenter (2394-Earthworks) urges EPA to eliminate pollution from routine flaring except in emergency situations and to define the term “emergency” clearly and narrowly. The commenter recommends that exemptions only be applicable to only short-term and temporary flaring. They further recommend that EPA also consider adding a certified technical infeasibility demonstration that requires an independent third party to conduct the demonstration and should require additional documentation to prove that no other gas recovery options are available.

Response II-6-60: The final rule has distinguished routine flaring and temporary flaring, and temporary flaring is allowed in specified situations. See the responses to II-6-54 and II-6-6 and Section XI.F.2.f of the final rule preamble.

Comment: Commenter (2241- Utah Department of Natural Resources (UDNR)) states that there is no need for further federal regulations, as the state already has rules in place for managing methane emissions. In creating an overlay to this state rule, the EPA will only create a difficult process of state approval and enforcement of its own requirements, states the commenter. By way of example, the commenter explains that Utah has specific rules governing the venting and flaring of associated gas from oil wells.<sup>203</sup> The commenter explains that the rule has been in place for nearly 40 years (with only minor modifications) and the state’s petroleum industry has adapted well to the requirements of the rule. Further, the commenter states that owners and operators understand that the Utah Division of Oil, Gas and Mining (DOGM) will work collaboratively to offer reasonable solutions to gas venting/flaring situations that both prevent waste of resource while economically producing from wells that may otherwise sit idle or be plugged prematurely.

Response II-6-61: EPA appreciates the robustness of Utah’s state rules to reduce methane emissions and applauds these efforts. However, the NSPS OOOOb and EG OOOOc are national-level rules developed under the authority of the Clean Air Act. When Utah is adopting the emission guidelines in EG OOOOc into their state rules, strong state regulations will make adoption of state guidelines less disruptive for operators than would otherwise be the case in the absence of such standards.

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<sup>203</sup> See Utah Administrative Code R649-3-20, Gas Flaring or Venting.

#### 6.2.4.6 Compliance Timeframe for Flaring Restrictions

Comment: Commenter (2360-Devon Energy) reports that they are actively working to reduce flaring of associated gas across each of its operating areas and has committed to eliminate routine flaring, as defined by the World Bank, by 2030. Since the commenter's standard practice is to only bring wells online where adequate sales line capacity exists, the commenter supports the restriction of the routine flaring of associated gas from oil wells that are considered "new" sources. The commenter encourages, however, the EPA to recognize the infrastructure challenges that may affect "existing" sources, and suggests 2030 as an appropriate compliance timeframe, consistent with the World Bank, which many operators already commit to or align with in voluntary initiatives.

Response II-6-62: EPA greatly appreciates the efforts by this commenter to pro-actively eliminate routine flaring in the absence of a federal regulation or guidelines. The final rule is consistent with the approach being taken by this company and therefore, should not impose restrictions that were not already being undertaken by the company to improve the environment.

#### ***6.2.5 Beneficial Use/Useful Purpose***

Comment: Commenter (2254-Permian Basin Petroleum Association (PBPA)) states that for wells producing associated gas, BSER is routing to a sales line, onsite use of gas and other "useful purposes" according to the proposed rule. The commenter contends that the EPA lacks authority in the CAA to render judgments on "useful purposes." After all, if an operator burns gas in a flare that has a 98 percent efficiency or burns it as fuel in a generator that also has a 98 percent efficiency, those circumstances have the same emissions. The commenter suggests that EPA leave to state agencies with jurisdiction over control of state resources what "useful purposes" or "beneficial uses" are. With that being said, the commenter believes EPA should allow a broad range of onsite beneficial purposes, and the commenter supports EPA's conclusion that "beneficial uses of the associated gas"—such as on-site use or reinjection into another well for enhanced oil recovery—should be deemed "equivalent" to the identified BSER of routing the gas to a sales line. To ensure consistency with corresponding state regulations, the commenter suggest that EPA could draw upon state definitions of beneficial purposes, such as those used in New Mexico.<sup>204</sup>

Response II-6-63: EPA points out a significant flaw in the commenter's example. If the associated gas is flared and a generator is also used onsite, there will be emissions resulting from both the combustion of the associated gas in the flare and the combustion of the fuel for the generator. Thus, if the associated gas is used as the fuel for the generator the emissions will be 50 percent less.

Also, while EPA disagrees with the assertion by the commenter regarding EPA's authority, we do believe that limitations should not be placed on "beneficial use". The specific uses that were specified in §60.5377b(b)(2) of the proposed rule and §60.5391c(b)(1) of the emission guideline

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<sup>204</sup> 19.15.27.9 NMAC.

(methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas) have not been retained in the final rule.

Comment: Commenter (2326-AXPC) suggests that the EPA not require consideration of predetermined beneficial uses for oil well associated gas, and, if EPA retains such a list, any included beneficial use must be commercially viable. The commenter states that the EPA proposes that operators must certify that use of “recovered gas for another useful purpose that a purchased fuel or raw material would serve” is not feasible “due to technical or safety reasons” before the operator may control associated gas onsite. They add that EPA proposes the feasibility analysis must include consideration of using gas for “methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas.” The commenter fully supports the beneficial use of natural gas where reasonably feasible and cost-effective and further supports development of additional technologies that would provide a broader range of potential beneficial uses. The commenter believes that the EPA’s inclusion of a predetermined list of uses suggests EPA has determined each of these beneficial uses is technically feasible, commercially available, and appropriately included as part of associated gas BSER. The commenter contends that, EPA, however, has provided no support for this apparent determination.

Accordingly, commenter (2326-AXPC) requests that EPA remove this list of beneficial uses. Further, to the extent EPA maintains such a list of beneficial uses, the commenter requests that EPA remove any unproven “emerging technologies.” The commenter states that CAA section 110(j) provides the appropriate pathway for sources to evaluate emerging technologies to meet NSPS. According to the commenter, requiring evaluation of unproven emerging technologies sidesteps both the BSER demonstration and the CAA section 110(j) process in violation of the CAA.

In the preamble, the commenter (2326-AXPC) reports that the EPA solicits comment on potential emerging technologies that could expand the universe of beneficial gas use and provides two examples of what it considers to be emerging technologies – methane pyrolysis and condensing gas and transporting it to other sites for use. They add that the EPA cites two comments in support of these emerging technologies. One commenter – a company in development of a methane pyrolysis solution – suggests that EPA should adopt methane pyrolysis as an express useful purpose in the rule but precedes this suggestion with an admission that its methane pyrolysis solution is neither scaled nor readily available for implementation. The commenter then requests that EPA grant a performance standard waiver for its unproven technology.<sup>205</sup> In fact, the commenter indicates its technology is in early stages of testing and has not been tested in a field setting.

Commenter (2326-AXPC) fully supports development of methane pyrolysis as a commercially scaled and available technology to reduce gas flaring; however, it is not commercially available today, and EPA should not require every beneficial use analysis to evaluate such an unproven solution. While one-off methane pyrolysis use may be technically possible, the commenter notes that methane pyrolysis is not a commercially feasible solution on the scale of implementation that may be required under this proposed rule. The commenter believes that the EPA’s express

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<sup>205</sup> See Document ID No. EPA-HQ-OAR-2021-0317-0594, -0595.

inclusion of it as a beneficial use in the final rule suggests methane pyrolysis is feasible (including on a commercial scale), while it is not, and would provide a windfall to this commenter.

The company supporting methane pyrolysis suggests a couple of pathways for approving the use of its methane pyrolysis technology – a CAA section 110(j) waiver and a commercial demonstration permit. Commenter (2326-AXPC) encourages the company to evaluate these paths; however, they believe that neither is a pathway to including its product as a required consideration in a NSPS or EG control evaluation.

Regarding condensing gas and transporting it offsite for use, EPA cites one comment that makes no mention of condensing gas. The commenter (2326-AXPC) notes that they can only guess that EPA means to reference the one sentence in the comment that suggests gas can be compressed and trucked to a processing plant or other location with no support for whether this solution is feasible or safe.

While commenter (2326-AXPC) believes that EPA should not expressly include any enumerated beneficial use and leave operators to determine the universe of beneficial uses reasonably available, if EPA includes any list of beneficial uses, the commenter requests that EPA remove technologies that are not proven and/or commercially available, including methane pyrolysis and condensing gas and transporting it offsite. The commenter states that including these technologies in a list of feasible beneficial uses that operators must consider in every associated gas control analysis sidesteps the requisite BSER analysis in violation of the CAA.

With respect to converting gas to liquid, commenter (2326-AXPC) provides that current gas liquefaction technology is capable of converting only the heavier-end gaseous hydrocarbons to liquid, requiring the control of methane and potentially other lighter-end hydrocarbons that remain in the gaseous phase following processing. Thus, gas to liquid conversion will not provide for complete use of the gas stream. Additionally, the equipment necessary to process gas to liquids is expensive to deploy and maintain and of limited commercial availability. While gas to liquid conversion may be viable in some instances, it is not a universally viable solution. Accordingly, the commenter requests that EPA remove gas to liquids conversion from the list of beneficial uses that operators must consider.

Finally, commenter (2326-AXPC) states that the EPA includes the production of liquified natural gas in its list of beneficial uses. While operators have removed natural gas liquids from field gas using equipment deployed to or near well sites, the commenter reports that this equipment has proven to be an unreliable permanent solution for several reasons, including vendor availability and safety. The commenter supports the expanded utilization of equipment that can extract natural gas liquids from field gas in the upstream sector; however, they believe it unnecessary to expressly include this as a consideration in a technical infeasibility analysis. Accordingly, the commenter requests that EPA remove the production of liquified natural gas from the list of required beneficial use considerations.

Response II-6-64: We agree with the commenters that limitations should not be placed on “beneficial use”. The specific uses that were specified in §60.5377b(b)(2) of the proposed rule

and §60.5391c(b)(1) of the emission guideline (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas) have not been retained in the final rule.

Comment: Commenter (2428-API) suggests that using associated gas as purge or pilot gas for a control device should be considered beneficial use. Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, the commenter notes that the NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in 40 CFR 60.5377b(a)(2), the commenter (2428-API) requests that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to 40 CFR 60.5377b(a)(2) (underlined text indicates new text):

Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.

As an alternative, the commenter (2428-API) suggests that EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under 40 CFR 60.5377b(a)(3).

Response II-6-65: As discussed in Responses II-6-63 and 64 of this Chapter, EPA has removed the specific list of beneficial uses of associated gas that must be evaluated to allow innovative solutions and emerging technologies. However, in general, EPA does not believe that using the associated gas as a purge or pilot gas for a control device is an acceptable option. This represents a significant potential loophole via which associated gas could be routed to a flare or combustion device. However, the EPA recognizes that there could be limited circumstances where this represents a legitimate beneficial use. For example, if the volume of associated gas is very low and equivalent to the amount of pilot gas that would otherwise be used for the flare. Therefore, the final rule does not specifically prohibit this usage. However, EPA would heavily scrutinize any such usage.

Comment: Commenter (2248-NDPC) suggests that the EPA adopt a broad definition of beneficial use, and use the list as suggested possible beneficial uses and not be prescriptive. There are a lot of variables in the different oil and gas regions (e.g., weather, formations, distance to populated areas) that may make one beneficial use more effective than others. For example, in North Dakota, the weather is extreme. The formation is very tight and thin and not conducive to permanent storage of natural gas. There may not be nearby population centers that could take advantage of additional power generation. There may be other technologies that can be deployed to take advantage of waste heat from the flare gas to generate power for onsite use (e.g., Thermo Electric Generation).



Response II-6-66: As discussed in Responses II-6-63 and 64 of this Chapter, EPA has removed the specific list of beneficial uses of associated gas that must be evaluated to allow innovative solutions and emerging technologies.

Comment: Commenter (2218-TCEQ) supports emerging technologies as potential methods for controlling emissions from oil and gas facilities and recommends that the rules allow the use of emerging technologies as a recognized method of achieving a beneficial use for associated gas. The commenter reports that some companies use the associated gas as fuel for electric generating units or compress the gas and send it to another site for processing. The commenter believes that useful purpose should include, but not be limited to, uses or purposes that a purchased fuel or raw material would serve. The commenter also believes that useful purpose should not be explicitly defined in the rule language, and that the owner or operator can provide a demonstration or certification that they meet this criterion. Due to the unpredictable nature of technological advancement, the commenter believes it would be shortsighted for EPA to limit this aspect of the rule to only narrowly defined or specified processes or technologies. Certain technologies for reducing methane and other greenhouse gas emissions, such as gas compression for offsite transport, can also result in collateral emissions of other regulated pollutants which are subject to NAAQS.

Response II-6-67: As discussed in Responses II-6-63 and 64, EPA has removed the specific list of beneficial uses of associated gas that must be evaluated to allow innovative solutions and emerging technologies.

Comment: Commenter (2283-Endeavor Energy) generally supports EPA's conclusion that "beneficial uses of the associated gas" such as on-site use or reinjection into another well for enhanced oil recovery-should be deemed "equivalent" to the identified BSER of routing the gas to a sales line, and recommends that EPA allow a broad range of on-site beneficial purposes in recognition that operators will need flexibility to pick the best option for their operations based on the particular well site.

Response II-6-68: As discussed in Responses II-6-63 and 64, EPA has removed the specific list of beneficial uses of associated gas that must be evaluated to allow innovative solutions and emerging technologies.

Comment: Commenter (2175-Crusoe Energy) recommends that their digital flare mitigation system (DFM) be included as an example of an emerging technology. The Proposal includes several examples of emerging technologies based on information provided by commenters in response to the November 2021 proposal. Specifically, EPA notes, "[e]xamples of such emerging technologies provided by commenters include methane pyrolysis and condensing the gas and transporting it to other sites for use." The commenter provides that their DFM technology is comparable to these provided examples as it also converts gas that would otherwise be flared into energy that can be used for high-powered computing. The DFM reduces methane emissions at a 99.9 percent efficiency, compared to an average combustion efficiency of only 91–93 percent in a flare, while simultaneously decreasing the carbon footprint of high-performance computing and removing datacenter load from the grid. The commenter states that

their DFM technology therefore provides a two-pronged emissions avoidance and can typically do so without cost to producers.

In addition, the commenter (2175-Crusoe Energy) explains that DFM technology provides additional environmental benefits. By reducing flaring and methane emissions, the commenter states it also helps to reduce levels of criteria air pollutants such as nitrous oxides (NO<sub>x</sub>), carbon monoxide (CO), and VOCs, which are linked to adverse human health effects. Relative to flaring, the DFM results in a 74 percent reduction in NO<sub>x</sub> emissions, a 95 percent reduction in CO emissions, and a 99 percent reduction in VOC emissions. Lower levels of methane emissions and these air pollutants also reduce the amount of ground-level ozone and improves air quality. By reducing these air emissions, the commenter notes that DFM further benefits the environment and advances EPA's environmental justice initiatives of reducing overall emissions in affected communities.

Commenter (2175-Crusoe Energy) concludes by requesting that DFM and similar technologies be considered an example of another beneficial use and that EPA provide clear guidance for operators and the states in any final rule so they know with certainty.

Response II-6-69: EPA agrees that the DFM system described by the commenter offers promise as beneficial use option for associated gas to eliminate the routine flaring or venting of associated gas. However, this statement does not indicate that EPA completely endorses DFM as an alternative to routing to a sales line for all applications. The commenter compares the impacts of DFM for a flare, which is not appropriate. An acceptable beneficial use must be comparable to routing to a sales line or using it as an onsite fuel source.

Comment: Commenter (2175-Crusoe Energy) points out that in the proposal, EPA notes that it interprets the third criterion, "used for another useful purpose", to include emerging techniques but is soliciting comment whether an additional criterion should be added to make this clear." The commenter responds to this solicitation by stating that they do not think additional criteria are necessary and is of the belief that the agency should leave the standard open and flexible to allow for future innovation that it may not be able to predict at this time. So long as a technology appears beneficial and can meet the BSER standard, the commenter believes it should qualify as a beneficial use. According to the commenter, rigid requirements or a complicated approval process would only stymie innovation. The commenter notes that many of the benefits achieved by current technologies (such as cloud computing) may not have even been considered 10 or 15 years ago, and many new benefits or uses for stranded gas may emerge in the upcoming years. To best address the climate crisis, the oil and gas industry needs new, innovative solutions in real time. The commenter contends that, given how time intensive it is for EPA to revise regulations or even to issue guidance as new technologies develop, it would be best for the agency, industry, and the environment if EPA's final rule allows broad latitude for new technologies to develop and help address emissions in the future.

Commenter (2175-Crusoe Energy) states that EPA's decision to confirm that the "used for another useful purpose" criterion includes emerging technologies is also consistent with the text and purposes of the CAA. The commenter provides that CAA section 111(a) of the Act provides that BSER should be determined after considering a variety of factors, including the cost of

emissions reductions, energy requirements, and health and environmental impacts. The D.C. Circuit has interpreted section 111(a) of the Act as authorizing EPA to “embrace[] consideration of technological innovation as part of [the BSER] balance” and as encouraging EPA to promote “the stimulation of technologies.” The commenter adds that the legislative history of the CAA likewise confirms that Congress intended BSER to “encourag[e] the development of innovative technological means of achieving equal or better degrees of control.” Indeed, Congress was so concerned with ensuring that EPA did “not stymie technological innovation” that it developed several pathways through which emerging technologies could be deployed even if they do not yet meet all BSER requirements, including, among other things, technology waivers under CAA section 111(j) and permitting the use of commercial demonstration permits.

Commenter (2175-Crusoe Energy) states that their DFM technology is already sufficient to satisfy the proposed 95 percent BSER, meaning that no waiver or demonstration permit would be needed. But the fact that Congress elected through CAA sections 111(a) and 111(j) to promote technological innovation confirms that EPA, when it promulgates any final rule, should make it unmistakably clear that (1) emerging technologies can be used to satisfy the “used for another useful purpose” component of BSER and (2) Crusoe’s DFM technology is a promising example of just such a “useful purpose.” Especially given the significant level of ongoing technological innovation in this area, the commenter believes that the EPA should use this opportunity to clarify that, unlike in generations past, terms like “beneficial use” and “another useful purpose” need not refer exclusively—or even primarily—to reallocating stranded gas for use as an onsite fuel source for the processing of other hydrocarbons. According to the commenter, the EPA should instead take advantage of its power to set flexible standards by crafting forward-looking, open-ended regulations that will encourage the use of DFM and other like technologies.

As explained above, commenter (2175-Crusoe Energy) does not believe that additional criteria are necessary or appropriate. However, to the extent EPA does include such criteria, the commenter states that their DFM technology should qualify because, as discussed above, it can demonstrate meeting the 95 percent emissions reduction rate, creates a beneficial use for gas, has been proven viable in the field, and is safe, reliable, and commercially available. The commenter therefore asks EPA to make clear in the preamble that DFM or similar technologies meet EPA’s criteria to avoid regulatory uncertainty.

Response II-6-70: EPA agrees that the rule should allow and encourage the use of emerging technologies to use the associated gas in a beneficial manner to avoid venting or flaring. However, the commenter has mischaracterized the BSER determination. BSER, for both new and existing sources, was determined to be routing to a sales line. As discussed in the supplemental proposal preamble (87 FR 74779), the EPA determined that beneficial uses of the associated gas for options that are equivalent in terms of emission reduction to the identified BSER. Therefore, as discussed in Response II-6-69, it is not appropriate to compare DFM or any other potential option to a flare, but rather it must be compared to routing to a sales line or using as an on-site fuel source.

Comment: Commenter (2175-Crusoe Energy) agrees with the recommendation that a list of examples should be included in the final rule for the purpose of regulatory clarity. The commenter would also request that DFM technology be included in any such list in the final rule.

They add that it should be made clear that this list should not be interpreted as exclusive or exhaustive, but rather intended to give operators and states examples of beneficial uses that EPA would accept in compliance with the standards of performance. Should EPA determine not to include such a list of examples, the commenter believes it should instead provide a clear and streamlined way for other beneficial uses to be pre-approved. This way, the regulated community will be better prepared to make the investments necessary to comply with the rule, new innovations with climate benefits will not be stymied by a time-consuming regulatory approval process, and EPA staff will not be overwhelmed with new administrative burdens.

Commenter (2175-Crusoe Energy) encourages EPA to provide the same list of emerging technologies as examples that states may use in their EGs. The commenter suggests that this should be done to provide clarity and consistency to the regulated community and to states as they develop their EGs.

Response II-6-71: See Responses II-6-69 and 70 of this Chapter.

Comment: Commenter (2175-Crusoe Energy) supports EPA’s proposal to use a BSER that allows for innovative solutions. According to the World Bank’s Global Gas Flaring Tracker Report, 144 billion cubic meters (bcm) of natural gas was flared in 2021. The commenter explains that much gas “could have potentially generated some 1,800-Terawatt hours (TWh) of energy—almost two-thirds of the European Union’s net domestic electricity generation.” Instead, it was burned away with no discernible value or purpose. However, the commenter suggests that the biggest problem with flaring is that it does not fully combust the methane in this wasted gas. As EPA has reported, over a 20-year timeframe, methane is over 80 times more potent than carbon dioxide as a greenhouse gas (GHG). “Oil and natural gas operations are the nation’s largest industrial source of methane,” and that methane “is responsible for approximately one-third of current warming resulting from human activities.” The commenter reports that Environmental Defense Fund’s Permian Methane Analysis Project found that three times more methane is leaked in the Permian Basin than EPA estimates. Most recently, a University of Michigan study of more than 300 flares found that flaring releases five times more methane in the U.S. than previously estimated.

Commenter (2175-Crusoe Energy) strongly supports EPA’s Proposal to broadly expand what is considered a “beneficial use”. While regulation plays an important role in limiting methane emissions, the commenter supports EPA’s approach of encouraging new technologies, private innovation, and site-specific solutions (particularly when a sales line is not available). This approach will help foster economic growth and energy security in an environmentally beneficial way during our energy transition.

Response II-6-72: See Responses II-6-69 and 70 of this Chapter.

Comment: Commenter (2257-Michigan Oil and Gas Association (MOGA)) provides discussion regarding the innate issues regarding bringing associated gas to a “useful purpose rather than flared”. The commenter notes that every producer would like the ability to sell all produced assets. On most occasions, the commenter states that the ability and cost are not feasible because of conflicting regulations, landowner & community objections, production sharing contract

(PSC) restrictions, and the associated cost of pipeline metering, compression, and transfer gate installation. The commenter explains that many wells drilled in the U.S. are not located at convenient spots. The inconvenient locations are in rural locations such as farmland, forests, and sparsely populated areas. Because these areas are remote and often isolated, transmission or gathering lines that collect gas are located closer to major distribution areas. The natural gas produced in these remote areas is referred to as “stranded gas”. The term “stranded” is used because the value of the gas will not pay for the pipeline needed to move the gas to a distribution line. If multiple wells are in a micro-geographic region, then connecting the flowlines to a distribution point, may justify the installation. However, landowners may object to having flowlines in their fields and local communities may not want subsurface piping down road easements, crossing driveways and stream crossings. So, the natural gas stays stranded, except for wellsite fuel or power generation. The commenter requests that the EPA discuss and clarify whether the Biden Administration is proposing financial, regulatory, and political support necessary to install natural gas lines to move stranded gas to a “useful purpose rather than flared”?

Response II-6-73: As discussed in the preamble for the final rule (Section XI.F.2), EPA recognizes that many wells were originally drilled in locations without the knowledge or expectation of a requirement that prohibits routine flaring. In these situations, the final emission guidelines and regulation allow the routing of the associated gas to a flare or control device if a demonstration is made (accompanied by a certification) that it is technically infeasible to route the associated gas to a sales line or use it for another beneficial purpose or inject or reinject it. Specifically, this is the case for existing wells under EG OOOOc modified and reconstructed wells under NSPS OOOOb, and new wells for which construction was commenced between the December 22, 2022, supplemental proposal and the date of publication of the final rule.

For new sources for which construction commences after the effective date of the rule, EPA concluded that, with the full knowledge and understanding of the final rule, owners and operators can plan ahead to ensure that one of the non-flaring options can be utilized. Therefore, the option to routinely flare is not allowed for new wells. Note that there is one caveat to this routine flaring prohibition is that new wells that commence construction for the first 6 months after the effective date of the final rule are allowed to routinely flare for a 2-year period, after which routine flaring is not allowed.

Comment: Commenter (2427-Utah Petroleum Association (UPA)) recommends that operators be allowed to use associated gas as an onsite fuel source and for onsite beneficial uses regardless of available gas takeaway pipeline capacity. The preamble to the supplementary proposal indicates that associated gas must be routed to a sales line and that only if access to a sales line is not available, the gas can be used as an onsite fuel source. However, the commenter believes that the final rules must allow use as an onsite fuel source and for onsite beneficial uses in any event, regardless of access to an available sales line or to available sales line capacity.

Commenter (2427-UPA)) states that oil and gas operations in the Uinta Basin do not have widely available access to electricity, and creating access would be very costly in most cases or not practical in other cases. Additional research into the feasibility of using solar power as a replacement for line electricity in the Uinta Basin has revealed that batteries will not charge or

operate successfully at some of the colder temperatures experienced in the Uinta Basin. For example, in Vernal, Utah, 21 days in January 2019 had low temperatures of 10 degrees Fahrenheit or lower and 22 days in the month had daytime high temperatures below freezing. 10 However, charge acceptance of batteries decreases at the cold temperatures and forcing high current to the batteries can build up pressure causing explosions of sealed batteries.<sup>11</sup>

Commenter (2427-UPA)) states that due to the waxy nature of the crude oil, operators must heat the separators and storage vessels to maintain the crude oil in a liquid and pumpable state. With the lack of available electricity, operators use associated gas to fire these heaters. Due to the lack of available electricity, operators also use associated gas to power the pump jack engines used for oil production. Operators also use associated gas to power other generators, wherever needed.

Moreover, commenter (2427-UPA)) states that if the final rule requires zero emissions pumps and controllers, the number of generators may increase; operators may need to use associated gas to operate engines needed for compressed air or to power local electricity generators to replace gas currently used to operate these devices. The use of associated gas in these manners is essential to efficient and successful production in the Uinta Basin. According to the commenter, these practices must be allowed to continue regardless of gas pipeline takeaway availability.

The commenter (2427-UPA) suggests that the regulatory language for NSPS OOOOb appears to allow these essential uses of associated gas in section 40 CFR 60.5377b. Similarly, they add that the language for EG OOOOc also appears to allow these essential uses of associated gas. The commenter supports the regulatory language as written in both rules. The commenter believes that any changes to this language to match the more restrictive wording of the preamble would severely restrict operations in the Uinta Basin and be detrimental to the economics of operation.

Response II-6-74: It EPA's intent that associated gas could be used as an onsite fuel source and for onsite beneficial uses regardless of available gas takeaway pipeline capacity. In the proposed rule any of the options listed in §60.5377a(a)(1),(2), (3) or (4) are equally acceptable compliance options. This is retained in the final rule, as well as in the EG OOOOc at §60.5391(a)(1) through (4).

### ***6.2.6 Allowance for Venting of Emissions***

Comment: Commenter (2241-Utah Department of Natural Resources (UDNR)) states that, for many operators, the decision to flare is largely dependent on the oil-to-gas price ratio, and the cost to capture and process the gas.<sup>206</sup> The commenter explains that while the added costs of flaring are likely the cheaper option when compared to the added costs of capturing, processing and sending the gas through a sales line (as this would require the construction of miles and miles of additional collection and distribution lines), there are still added costs, safety concerns, and other complexities associated with flaring. As such, the commenter would encourage that

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<sup>206</sup> U.S. DOE, Developing Technologies for Upcycling Associated Gas into Higher-Value Products, U.S. Department of Energy, available at: <https://www.netl.doe.gov/sites/default/files/2020-12/Upcycling-Associated-Gas-into-Higher-Value-Products-12-2020.pdf> (2020).

exceptions be added to the proposed rule allowing for venting in certain situations where neither flaring nor redirecting gas to a sales line is a feasible option (such as on remote public lands).

Response II-6-75: EPA does not believe there are any circumstances that warrant routine venting of associated gas. Thus, there are no such allowances in the final rule. EPA does recognize, however, that there are temporary reasons that venting may be necessary. Thus, in the final rule and emission guidelines, venting is allowed under the following circumstances and for the specific durations.

- For up to 12 hours per incident to protect the safety of personnel.
- For up to 30 minutes per incident during bradenhead monitoring.
- For up to 30 minutes per incident during a packer leakage test.

However, the final rule and emission guidelines only allow such venting for a total of 24 hours each calendar year. For more information, see the discussion in section XI.F.2.f of the final rule preamble.

Comment: Commenter (2433-EDF et al) touches on circumstances where venting may be warranted. The commenter acknowledges that venting may be necessary for safety.<sup>207</sup> In addition, they add that operators may need to vent for a very brief period during downhole monitoring activities, namely when monitoring the downhole pressure during bradenhead monitoring and packer leakage tests. The commenter reports that both Colorado and New Mexico allow operators to vent or flare during bradenhead monitoring.<sup>208</sup> Colorado limits bradenhead monitoring to 30 minutes.<sup>209</sup> New Mexico also allows operators to flare or vent during packer leakage tests.<sup>210,211</sup>

Response II-6-76: As discussed in Response II-6-75, the final rule allows temporary venting in specified circumstances,

### ***6.2.7 Access to a Sales Line***

Comment: Commenter (2248-NDPC) suggests that, when soliciting comments on what the definition of “access to a sales line” should be, the commenter reminds the EPA that in most cases, the midstream company that designs, builds, and operates the gas gathering system (sales line) and gas processing plants is not the same as the well owner and operators, landowners, and mineral lease owners. One entity has little control over the other. In addition to commercial availability/viability, a potential gas disposition method must be economically viable. For example, the commenter explains that a remote well site operator could identify a pipeline with sufficient capacity, but the closest pipeline with sufficient takeaway capacity maybe 100 miles away. The cost to build, maintain, and operate the connecting pipeline may well exceed the total

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<sup>207</sup> 2022 Joint Environmental Comments, supra note 1, at 181.

<sup>208</sup> N.M. Code R. § 19.15.27.8.D.(4).(i).

<sup>209</sup> Colo. 800/900/1200 SBP, supra note 450, at 86.

<sup>210</sup> N.M. Code R. § 19.15.27.8.D.(4).(j).

<sup>211</sup> Expert report of Thomas Alexander, supra note 435, at 6.

value of the gas that could be sold. According to the commenter, while it would be technically feasible to build this connecting pipeline, it is not an economically viable solution.

Commenter (3845-ND Congress) reports that energy producers must manage increasing volumes of gas associated with oil production, and the proposed rule's restrictions on flaring of associated gas would disproportionately impact operators in ND. While natural gas pipeline capacity in the state has grown over the years, based on the remote nature of operations, there are still cases where natural gas pipelines are not readily available, particularly on federal and tribal lands where permitting issues impede infrastructure deployment. Even when available, they add that issues such as product incompatibility with infrastructure, third-party maintenance, market conditions, or extreme cold weather can all restrict an operator's ability to send gas to pipelines for sales. Similarly, the unique geography and extreme cold weather in the region can make other beneficial uses of the gas infeasible.

In some cases, the commenter (3845-ND Congress) contends that an alternative to flaring may impose greater costs than the value of the gas itself. In such situations, operators cannot be expected to forgo flaring which eliminates 98 percent or more of the methane. To do so would be inconsistent with the mandate of the CAA, which expressly requires consideration of costs by EPA when establishing NSPS. As a result, the commenter believes that EPA's approach will leave many operators with no option but to shut-in production. According to the commenter, any reduction in production would also reduce royalties, directly impacting the livelihoods of North Dakotans and members of the Three Affiliated Tribes that rely on this key source of revenue. Further, the commenters note that, if operators are unable to comply with EPA's burdensome regulations in North Dakota, they may shift operations out of state, drastically reducing production and associated income.

Lastly, the commenter (3845-ND Congress) reports that, in fiscal year 2022, taxes on North Dakota oil and gas operations generated over two billion dollars to fund services for the people of North Dakota. These revenues support schools, infrastructure, improvements such as flood control projects, environmental reclamation activities, and tax relief for residents throughout the state. According to the commenter, any regulation that reduces or disincentivizes production operations will reduce available funds for these important efforts and harm North Dakotans.

Response II-6-77: EPA recognizes that situations exist for many existing wells that make routing the associated gas to a sales line or for one of the other approved purposes may be infeasible. For that reason, the final emission guidelines allow owners and operators to routinely route the associated gas from an existing well to a flare or control device, provided that they demonstrate it is technically infeasible to route it to sales line, use it as a fuel or for another beneficial purpose, or inject or re-inject it. The final rule does not, however, allow the routine flaring of associated gas from new wells. Therefore, moving forward, owners and operators of wells to be drilled in North Dakota (and elsewhere) will need to plan ahead so that the associated gas may be used for one of the approved purposes.

EPA points out that the commenters are overlooking the value of the options to BSER that EPA is allowing. When considering the economics of the well, it would be inappropriate for EPA to set BSER based only on "the total value of the gas that could be sold." In the example of a 100



mile gathering line, it is likely that it would be in the interest of the source to employ one of the alternatives to BSER.

Comment: Commenter (2414-Carbon Mapper and RMI (CM-RMI)) agrees that flaring variances last for a finite period and/or volume (whichever is reached first). The commenter explains that new usable sales pipelines or other infrastructure, feasible delivery points for compressed gas, technology, or discoveries in additional beneficial uses may present themselves as available later in the asset's life. The commenter also supports that such triggers (variance age, volume flared, or new developments/innovations) should trigger a new, full, and certified review similar to original variance requests.

Commenter (2414-CM-RMI) supports EPA in requiring operators to attempt to access an existing sales line, the preferred standard control option, and facilitate alternative off-site transport and use of associated gas. Furthermore, since sites operate for decades and sales lines are typically not under the control of the well owners and operators, the commenter recommends that operators include an attempt to collaborate with gathering system owners regarding both upcoming or proposed sales line projects and production projects, as this may inform and optimize sales lines route engineering. The commenter notes that, if enough operators collaborate with gathering system owners, gathering system owners may respond to the demonstrated need of sales pipelines in unserved/underserved areas. Otherwise, the commenter suggests that pipelines may not be developed due to a lack of discussion and identification of opportunity.

Response II-6-78: For existing associated gas wells, along with reconstructed or modified wells and those that commenced construction between the supplemental proposal and the final rule, owners and operators are allowed to routinely route the associated gas to a control or flare if a demonstration is made that it is technically infeasible to route to sales or one of the other approved options. However, consistent with the recommendations by the commenters, the final rule requires that this determination and certification be revisited every year because solutions, such as the building of new infrastructure, could have occurred.

## 6.3 Well Completions

### 6.3.1 Applicability

Comment: Commenter (2408-CO LGC) recommends that EPA extend its reduced emission completion (REC) requirements to non-hydraulically fractured wells, as is the case in Colorado<sup>212</sup> and New Mexico.<sup>213</sup> The commenter notes that, per the Statement and Basis for Colorado's rules "the Commission intends for its reduced emission completion standards to apply to all wells, regardless of whether they are hydraulically fractured."<sup>214</sup> New Mexico's rules similarly apply to all wells.<sup>215</sup> The commenter contends that the EPA gives no reason for exempting non-hydraulically fractured wells from controlling emissions during completions.

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<sup>212</sup> Id. at 903.c.(1).

<sup>213</sup> N.M. Code R. §19.15.27.8.C.

<sup>214</sup> COGCC SBP, 800/900/1200 Rule Series, at p. 81.

<sup>215</sup> N.M. Code R. §19.15.27.8.C.

Response II-6-79: The EPA has not extended the REC requirements that apply to hydraulically fractured wells to non-hydraulically fractured wells in the NSPS OOOOb final rule. The EPA does not have information to support the extension of well completion REC requirements to non-hydraulically fractured wells under NSPS OOOOb.

### ***6.3.2 Well Completions Requirements***

Comment: Commenters (2408-CO LGC, 2433-EDF et al) request that EPA follow Colorado's and New Mexico's example and prohibit venting during the initial flowback stage of completions.

The commenters (2408-CO LGC, 2433-EDF et al) specifically recommend that EPA follow the example set by Colorado and New Mexico, which require control of venting during initial flowback. They provide that the Colorado Air Quality Control Commission requires operators route flowback to enclosed flowback vessels after drill-out, and route emissions from flowback vessels to a device that achieves “a hydrocarbon control efficiency of at least 95%” or to a combustion device with “a design destruction efficiency of at least 98% for hydrocarbons.”<sup>216</sup> Colorado Oil and Gas Conservation Commission rules further require that operators “enclose all [f]lowback vessels...” and adhere to the Air Quality Control Commission rules requiring the use of enclosed and controlled flowback vessels.<sup>217</sup>

The commenters (2408-CO LGC, 2433-EDF et al) add that as part of the development of the Air Quality Control Commission rule, the Colorado Department of Public Health, and the Environment (CDPHE) conducted a cost-benefit analysis and found its completion requirements were incredibly cost effective, even assuming a worst-case scenario. To estimate the costs of its rule, Colorado assumed operators needed 10 to 15 500 barrel of crude oil (bbl) flowback vessels at a multi-well production facility. The CDPHE assumed new storage vessels would cost \$30,500 and used storage vessels would cost between \$7,000 and \$19,000; \$1,000 in one-time costs; and \$500 in annual operation and maintenance costs, assuming a 15-year lifespan for flowback tanks. Colorado found its annualized cost per flowback tank would be \$4,830 and, assuming an average of 12 flowback tanks, the annualized costs per wellsite are \$57,958.<sup>218</sup>

Commenter (2433-EDF et al) notes that they reviewed Colorado's estimate and found that it was reasonable and even likely conservative, as it represented a “‘worst-case cost effectiveness estimate’ because it assumed an operator would use the 12 flowback tanks only once, at one well site. According to the commenter, it is more likely operators would use the same flowback tank at multiple wells for the lifetime of the tanks.”<sup>219</sup> Relying on the CDPHE cost-effectiveness analysis, the commenter evaluated the policy prohibiting venting during the initial flowback

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<sup>216</sup> 5 Colo. Code Regs. §1001-9-D-VI.D.1.a.

<sup>217</sup> 2 Colo. Code Regs. §404-1-903.c.(1).

<sup>218</sup> CDPHE, Air Quality Control Commission, Cost Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7, p. 23 (September 4, 2020), available at [https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment\\_5.pdf](https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment_5.pdf).

<sup>219</sup> New Mexico Env. Improvement Board, In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Direct Testimony of Thomas Alexander, at 14 (2021)

stage in New Mexico.<sup>220</sup> The analysis found that controlling emissions during the initial flowback stage could be implemented at a cost of \$53.79 per ton methane. The commenter also estimated the cost-per-ton to reduce VOC emissions under this policy. Using the statewide average methane-to-VOC ratio for completions, the commenter estimated the cost effectiveness to be \$259.48 per ton VOC reduced. As such, the commenter contends that requiring control of emissions during the initial flowback stage is overwhelmingly cost-effective.<sup>221</sup>

Commenter (2408-CO LGC) notes that New Mexico similarly requires operators “collect and control emissions from each flowback vessel...” and route emissions to a control device that achieves a hydrocarbon control efficiency of at least 95 percent.<sup>222</sup> Operators must ensure that the control device “operates as a closed vent system...and that unburnt gas is not directly vented to the atmosphere.”<sup>223</sup>

Commenter (2433-EDF et al) states that a key difference between the New Mexico and Colorado rules is that New Mexico does not require flowback vessels to be “vapor tight” but rather requires them to deploy a control that operates as a closed vent system (CVS).<sup>224</sup> The commenter believes this slight variation in the requirements is appropriate, as concerns have been raised that the vapor tight language raises safety concerns.<sup>225</sup>

Response II-6-80: The EPA disagrees with the commenters that the NSPS OOOOb final rule should follow Colorado’s and New Mexico’s example and prohibit venting during the initial flowback stage of well completions. The EPA has maintained the December 2022 Supplemental Proposal requirements. Under 40 CFR 60.5375b (proposed and final rule text), operators must capture emissions during the separation flowback period of each well completion, unless it is technically infeasible to do so. The owner or operator must direct captured emissions from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. The rule provision for use of captured gas for “any useful purpose” provides flexibility such as use for mobile natural gas refrigeration units or natural gas generators for onsite electricity. Under the final rule, only if these options are not technically feasible (which may include the lack of infrastructure and gathering line concerns) would captured emissions be routed to a completion combustion device. Owners or operators also have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

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<sup>220</sup> New Mexico Env’t Improvement Board, In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Direct Testimony of Hillary Hull, at 15 (2021).

<sup>221</sup> CDPHE, Air Quality Control Commission, Cost Benefit Analysis for Proposed Revisions to AQCC Regulation No. 7, p. 23 (September 4, 2020), available at [https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment\\_5.pdf](https://downloads.regulations.gov/EPA-HQ-OAR-2021-0668-0758/attachment_5.pdf).

<sup>222</sup> N.M. Code R. §20.5.20.127.B.(1).

<sup>223</sup> N.M. Code R. §20.5.20.127.B.(1)(2).

<sup>224</sup> N.M. Code R. §20.5.20.127.B.(2) (2023).

<sup>225</sup> N.M. Env’t Improvement Bd., In the Matter of Proposed New Reg. 20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants No. EIB 21-27 (R), Notice of Intent to Present Rebuttal Technical Testimony on Behalf of Oxy USA Inc., Testimony of Danny Holderman, Ex. 2, pp. 3-4 (2021).

Comment: Commenter (2213-Occidental (Oxy)) provides that they implement RECs to capture gas at the wellhead during completions and minimize releases to the atmosphere. They note that they plan their drilling programs and facilities in tandem to deploy the necessary infrastructure in advance of well completion so that methane and other emissions can be captured and sent to processing facilities and pipelines for sale. The commenter believes a framework could be adopted prospectively for the well completion section of the rule that applies many of these same principles in order to reduce/eliminate the need for flaring.

Response II-6-81: Ideally, most owners or operators plan their drilling programs and facilities similarly to reduce/eliminate the need for flaring. The NSPS OOOOa and NSPS OOOOb rules are structured to only allow for venting/flaring of releases during completions where it is technically infeasible to capture emissions from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. Owners or operators have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

Comment: Commenter (2177-Ute Indian Tribe) recommends that EPA remove the following notification requirement, stating that it is not appropriate to require a well completion notification in the regulation:

If you own or operate a well affected facility, you must notify the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format. If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of this paragraph.

Response II-6-82: The EPA disagrees with the commenter that the cited notification requirement is not appropriate and has not made the commenter's recommended change in the final rule. This notification has been required under NSPS OOOOa for several years without issue and is maintained in NSPS OOOOb. As required (and noted above), if an owner or operator is subject to state regulations that require advance notification of a well completion and you meet that requirement, then you are considered to have met the advance notification requirements of NSPS OOOOb.

### ***6.3.3 Technical Infeasibility Exception***

Comment: Commenters (2408-CO LGC, 2433-EDF et al) urge EPA to remove the technical infeasibility exception for the separation flowback stage as Colorado and New Mexico have done.

Commenter (2408-CO LGC) contends that broad, undefined technical infeasibility exemptions open the door to abuse and present enforcement challenges and notes that neither New Mexico nor Colorado includes a technical infeasibility exemption in its completion rules.<sup>226</sup> The commenter notes that New Mexico requires operators capture and route natural gas from separation equipment to a flowline or collection system or use the gas on-site.<sup>227</sup> New Mexico permits flaring only if necessary for safety<sup>228</sup> or temporarily if natural gas does not meet gathering pipeline quality specifications.<sup>229</sup> The commenter adds that Colorado similarly only permits flaring with pre-approval<sup>230</sup> or if necessary to ensure safety during an upset condition.<sup>231</sup> The commenter provides that safety flaring during an upset condition is limited to 24 hours.<sup>232</sup>

Commenter (2433-EDF et al) suggests that combustion only be allowed during an upset condition, as New Mexico has required.<sup>233</sup> The commenter maintains that this will help ensure that the technical infeasibility exception is not misused, and ensure operators are using equipment that is appropriately sized for the needs of the flowback scenario.<sup>234</sup> The commenter also recommends EPA define "Upset Condition" to mean "a sudden, unavoidable failure, breakdown, event, or malfunction beyond the reasonable control of the operator that substantially disrupts operations but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation, or other preventable equipment failure or breakdown." The commenter notes that the definition draws from the definition of "Upset Condition" in Colorado<sup>235</sup> and the definition of malfunction in the New Mexico rules.<sup>236</sup>

Response II-6-83: The EPA has not eliminated the REC technical infeasibility exception for the separation flowback stage in the NSPS OOOOb final rule. Please see section VI.E.2 of the preamble to the 2016 NSPS OOOOa final rule<sup>237</sup> for a discussion of the reason for the technical infeasibility exemption. In the 2016 NSPS OOOOa final rule, the EPA strengthened the documentation and recordkeeping requirements in order to claim the technical infeasibility

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<sup>226</sup> 2 Colo. Code Regs. §404-1-903.c.(1).

<sup>227</sup> N.M. Code R. §19.15.27.8.C.(2).

<sup>228</sup> Id. at §19.15.27.8.C.(2)(b).

<sup>229</sup> Id. at §19.15.27.8.C.(3).

<sup>230</sup> 2 Colo. Code Regs. §404-1-903.c.(3)(A) (allowing flaring if approved on gas capture plan); Id. at 903.c.(3)(B) (allowing flaring if approved by Director and accompanied by justification for need to flare, plans to capture the gas, and estimate of anticipated flaring amount and duration).

<sup>231</sup> Id. at 903.c.(3)(C).

<sup>232</sup> Id.

<sup>233</sup> N.M. Code R. §19.15.27.8.C.(2)(b) (2023).

<sup>234</sup> Env't Def. Fund et al., Comment Letter on Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Dkt. No. EPA-HQ-OAR-2021-0317-0844 (Jan. 31, 2022), at 179-80.

<sup>235</sup> 2 Colo. Code Regs. §404-1-100-21 (2023) (defining upset condition as "a sudden unavoidable failure, breakdown, event, or malfunction, beyond the reasonable control of the Operator, of any equipment or process that results in abnormal operations and requires correction").

<sup>236</sup> N.M. Code R. §19.15.27.7.M (2023) (defining a malfunction as "sudden, unavoidable failure or breakdown of equipment beyond the reasonable control of the operator that substantially disrupts operations but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation, or other preventable equipment failure or breakdown.").

<sup>237</sup> 81 FR 35852-35853, June 3, 2016.

exemption, and EPA continues to believe that there are instances where performing a REC is technically infeasible and the rule needs to allow for relief in those instances.

#### ***6.3.4 Definition of Hydraulic Fracturing - Well Completions***

Comment: Commenter (2179-Kansas Independent Oil & Gas Association (KIOGA)) is concerned with the definition of “hydraulic fracture.” The commenter believes well completions performed in Kansas, and other similar areas, do not meet EPA's definition of hydraulic fracturing for various geologic and engineering reasons. The commenter recommends that the definition in NSPS OOOOa be amended to explicitly exclude conventional wells from the regulation because the work performed does not meet the definition provided in the regulation. The commenter notes that operations in Kansas do utilize pressurized fluids that contain water, proppant, and/or chemicals, however most of the operations use a process that neither penetrates tight formations like shale or coal, nor require high rate, extended flowback. They explain that most Kansas operations result in little to no flowback from formations with higher quality reservoir properties than shale or coal. According to the commenter, ignoring those two facts discounts two thirds of the definition as outlined by 40 CFR 60.5430a. The commenter contends that enforcing this regulation based on "the process of directing pressurized fluids" alone; but not based on the type of formation or subsequent flowback directly ignores the criteria outlined by this regulation.

The commenter (2179-KIOGA) states that these two criteria were included in the definition of hydraulic fracturing, as pertaining to this regulation, to distinguish the varying completion styles of small, vertical, conventional drilling targets from large, horizontal, tight, unconventional drilling targets (such as shale and coal). The commenter also assumes that this distinction was developed due to the difference in potential greenhouse gas (GHG) emissions from the dissimilar formation types and completion styles. While the amount of GHGs emitted from each reservoir type has yet to be quantified, the commenter assumed the GHG emissions will be proportional to the amount of hydrocarbons produced (i.e., the more oil and gas a well produces has the potential to produce greater amounts of GHGs that well may emit). According to the commenter, the average Estimated Ultimate Recovery (EUR) for vertical wells in Kansas is 20,000-30,000 bbl/well, where shale wells yield much higher EURs. Per Energy Information Administration (EIA) data, the average EUR is 168,000 bbl/well for an Eagleford shale well and 243,000 bbl/well for an Eastern Bakken well. Based on these numbers, a typical Kansas well will yield — 10 percent of the oil, and theoretically 10 percent of the GHGs, of a typical oil shale well. The commenter further compares typical reservoir and completion parameters for tight shale formations and for conventional formations targeted in Kansas, indicating that many of the terms mentioned in the definition provided in 40 CFR 60.5430a are also included as a comparison between wells drilled in Kansas and by operators targeting tight, unconventional, shale formations.

Regarding geologic criteria, the commenter (2179 - KIOGA) states that most reservoirs within Kansas produce from reservoirs that do not constitute tight formations, such as shale or coal formations, as defined within the standards of the EPA. According to the commenter, the formations targeted are conventional reservoirs that are different from unconventional shales and coals for four main reasons:

1. *Grain size* - Reservoirs in Kansas are carbonates and sandstones rather than shale or coal. The Wentworth grain size classification categorizes sands as being larger than 0.0625 millimeters (mm) while clays (main component of shale) are categorized as grains smaller than 0.0039 mm, more than ten times smaller than the finest-grain, conventional reservoir in Kansas. Furthermore, coal is not composed of consolidated grains, but rather consolidated, thermally mature organic matter.
2. *Organic content* - The shales and coals exploited outside of Kansas are targeted due to their organic content. Coal is composed of nearly 100 percent total organic content (TOC) whereas productive shales are typically greater than 2 percent TOC. Many of the major producing shales have much higher TOCs, some exceeding 10 percent. The conventional reservoirs in Kansas have only trace amounts of TOC at best. The TOC content is very important in shale and coal because the hydrocarbons being targeted are located within the porosity of the organic matter. Producing the hydrocarbons from the organic matter requires large hydraulic fracturing stimulation.
3. *Permeability* - In Kansas reservoirs permeability in locations is generally measured in millidarcies, and some are measured in darcies; while in shale reservoirs, permeability is measured in nano-darcies. The difference between a millidarcy and a nano-darcy is six orders of magnitude ( $10^{-3}$  vs.  $10^{-9}$  darcies, respectively). Because the permeability and nature of the formation types vary so much, the two reservoir types require two different analytical methods in order to measure rock properties.
4. *Producibility* - The finer grain size, nanoscale organic porosity, and low permeability of shale and coal require extended reach laterals with extensive fracturing to increase permeability over large drainage areas to achieve economical flow rates. Reservoir fluid flow typically does not occur outside of the stimulated rock volume. The larger grain size and higher permeability of the conventional reservoirs of Kansas require much less stimulation, and typically a much smaller drainage area, to achieve economical flow rates. Reservoir fluid flow will occur outside of the stimulated rock volume in the more permeable Kansas reservoirs.

Response II-6-84: Similar comments were received on the November 2021 NSPS OOOOb proposal. See response to these similar comments in Volume I, Chapter 16, Response I-16-1 of this RTC.

## **6.4 Liquids Unloading Operations**

### **6.4.1 Applicability**

#### **6.4.1.1 Affected Facility Definition**

Comment: Commenters (2248-NDPC, 2258-MSD, 2446-IPAA) consider the current definition of liquids unloading operations to be unclear. Commenter (2248-NDPC) requests clarification whether well liquids unloading operations only apply to gas wells as described in 40 CFR 98.

Commenter (2326-AXPC) appreciates the following changes or clarifications by EPA: (1) clarification of that the liquids unloading requirements apply to gas wells; (2) removing the

overly expansive modification trigger for well liquids unloading; and (3) removal of “design” as the determination of whether a well liquid unloading activity must comply with the requirements.

Commenter (2258- Marcellus Shale Coalition (MSC)) contends that EPA is attempting to use the proposed regulation to significantly increase their understanding of gas well liquid unloading by including an overly broad and poorly defined affected facility definition and by including wells that do not vent during liquid unloading. The commenter notes that EPA defines liquid unloading as: “*Liquid unloading* means the unloading of liquids that have accumulated over time in gas wells which are impeding or halting production.” According to the commenter, this broad definition will lead to a variety of interpretations concerning which production techniques, among the dozen or so employed in industry, this should apply to. The commenter provides that this will lead to poor consistency in the interpretation of what type of production techniques constitute liquid unloading which will create regulatory compliance uncertainty among reporters. The commenter contends that EPA acknowledges this by specifically asking the following “U.S. EPA has yet to reach a conclusion on whether certain types of liquids unloading events could be an operational change to a well. The EPA is therefore requesting comment on operational scenarios where a well liquids unloading event could constitute a modification.”

The commenter (2258-MSC) explains that liquid unloading techniques will change over the potential 30 or more years in the producing life of wells. Venting may be required at a particular time in a well’s life; however subsequent techniques may not vent as future unloading techniques evolve. For example, the commenter notes that the installation of a field wide gas lift system, or the addition of wellhead compression, or the reduction in gathering line pressures may occur in the later phases of well life that may not vent during liquid unloading. The commenter considers EPA’s attempt to use their current definition of liquids unloading for source applicability to be ambiguous. The commenter states that each type of liquid unloading activity may require a unique and thorough assessment to formulate appropriate regulations as potential emission sources. The commenter recommends EPA better understand these differences and develop regulations with enough specificity to avoid such ambiguity.

Due to the factors discussed, the commenter (2258-MSC) requests that EPA more narrowly define liquids unloading operations to clarify those activities regulated rather than all unloading activities as currently proposed. The commenter suggests defining liquids unloading operations as those operations that vent to the atmosphere. The commenter states that this action would clearly define the source and limit the recordkeeping to the liquid unloading events that vent to the atmosphere.

Commenter (2446-IPAA) notes that EPA is attempting to use the proposed regulation to significantly increase their understanding of the gas well liquid unloading by including an overly broad and poorly defined affected facility definition and by including wells that do not vent during liquid unloading. The commenter provides that EPA’s definition of liquid unloading is broad and will lead to a variety of interpretations concerning which production techniques, among the dozen or so employed in industry, this should apply to. The commenter contends that this will lead to poor consistency in the interpretation of what type of production techniques constitute liquid unloading which will create regulatory compliance uncertainty among reporters. The commenter states that EPA acknowledges this by specifically asking the following "EPA has



yet to reach a conclusion on whether certain types of liquids unloading events could be an operational change to a well. The EPA is therefore requesting comment on operational scenarios where a well liquids unloading event could constitute a modification."<sup>238</sup>

Response II-6-85: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and (3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS OOOOb. In the December 2022 Supplemental Proposal, the EPA proposed that, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured or hydraulically refractured. Nonetheless, EPA solicited comment in the December 2022 Supplemental Proposal on whether there are operational scenarios where a liquids unloading event could potentially constitute a modification. Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (*i.e.*, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). See section 6.4.1.2 of this Chapter for specific comments received and EPA’s responses on what constitutes a “modification” for well affected facilities that undergo liquids unloading. While a well affected facility that has been modified (*e.g.*, refractured) would include non-venting liquids unloading events, minimal recordkeeping and reporting requirements would apply to owners or operators of well affected facilities that do not vent during liquids unloading.

With regards to the commenter that requests clarification on whether well liquids unloading operation requirements only apply to gas wells as described in 40 CFR 98. The final rule text has been clarified to specifically state that liquids unloading operation requirements only apply to gas wells.

See sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and liquids unloading requirements. See section XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (2227-WEA, 2238-Southeastern Ohio Oil and Gas Association (SOOGA), 2254-PBPA, 2258-MSA, 2294-OOGA, 22391-Chesapeake Energy, 446-IPAA) assert that EPA should only regulate unloading operations that vent emissions.

Commenter (2238-SOOGA) requests that, with respect to the emissions standards for liquids unloading, EPA clarify that unloading which does not result in venting to the atmosphere should not be an affected facility, and that EPA include feasibility language from the preamble in the regulatory text.

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<sup>238</sup> 87 FR 74782.

Commenter (2227-WEA) provides that operators conducting liquids unloading operations with zero methane and volatile organic compound (VOC) emissions should not be subject to burdensome recordkeeping, reporting and other requirements. The commenter asserts that the rule should only apply to venting during liquids unloading. The commenter adds industry innovated to address the environmental problem of venting during liquids unloading, yet EPA is disincentivizing this innovation. Malfunctions of designed zero-emissions liquids unloading events would be addressed with designed venting events, with required best management practices (BMPs) that minimize emissions, and recordkeeping and reporting.

Commenter (2258-MSD) contends that the implementation of the rule would be easier if the standards only applied to wells that vent. The commenter suggests EPA develop emission requirements for facilities that vent emissions, not for facilities that would only vent emissions if something goes wrong or not as planned. In these situations, the commenter recommends EPA develop separate requirements that would apply.

Commenter (2391-Chesapeake Energy) notes that in the November 2021 proposal, EPA solicited comments on two approaches to defining the affected facility. The first approach defined the affected facility as every well that undergoes liquids unloading, while the second approach defined the affected facility as every well that undergoes liquids unloading using a method that is not designed to eliminate venting. 87 Fed. Reg. at 74781. Although numerous commenters supported the second option, EPA now proposes, in the December 2022 proposal, regulatory text implementing the first option.

The commenter (2391-Chesapeake Energy) opposes this approach because it imposes burdensome recordkeeping and reporting obligations on owners or operators in exchange for no environmental benefit for well unloading activities that do not vent. For example, owners or operators of well affected facilities where gas well liquids unloading occurs must submit annual reports (1) identifying the well affected facility; (2) disclosing the number of gas well liquid unloading operations that occurred there during the reporting period; (3) describing the unloading operation method used each time; and (4) reporting any deviations in detail along with corrective actions. See e.g., proposed 40 CFR 60.5410b(b) and 60.5415b(b). When unloading operations do not result in any vented emissions, these reports serve no purpose.

To avoid this result, the commenter (2391-Chesapeake Energy) recommends that the EPA clarify the standards for gas well liquids unloading operations apply only to those operations that result in emissions to the atmosphere. This action would appropriately limit the recordkeeping and reporting obligations, and it would still allow EPA to gather compliance information for a well that vents to the atmosphere during liquid unloading. The commenter adds that the EPA should also make similar changes to proposed 40 CFR 60.5390c in EG 0000c.

Response II-6-86: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and (3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS 0000b. In the December 2022 Supplemental Proposal, the EPA proposed that, in addition to 40 CFR 60.14, a

“modification” of an existing well occurs when an existing well is hydraulically fractured or hydraulically refractured. Nonetheless, EPA solicited comment in the December 2022 Supplemental Proposal on whether there are operational scenarios where a liquids unloading event could potentially constitute a modification. Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (*i.e.*, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). See section 6.4.1.2 of this Chapter for specific comments received and EPA’s responses on what constitutes a “modification” for well affected facilities that undergo liquids unloading. While a well affected facility that has been modified (*e.g.*, refractured) would include non-venting liquids unloading events, minimal recordkeeping and reporting requirements would apply to owners or operators of gas well affected/designated facilities that do not vent during liquids unloading.

For unloading technologies or techniques that eliminate venting of emissions during liquids unloading events, the final rule requires minimal recordkeeping and reporting.

For unloading technologies or techniques that could result in venting to the atmosphere, the final rule requires work practices be followed. Specifically, the final rule requires that owners or operators employ and document best management practices to minimize or eliminate venting of methane and VOC emissions for each gas well liquids unloading operation.

See sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and liquids unloading requirements. See section XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (2433-EDF et al.) supports the November 2021 proposal’s Option 1 in defining affected facilities to cover all wells undergoing liquids unloading as a critical requirement to ensure that operators do not simply claim to conduct liquids unloading events with zero emission techniques, when in reality venting is occurring. The commenter notes that EPA has recognized, “under some circumstances venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.*, a technology malfunction or operator error).”<sup>239</sup> The commenter contends that in some cases, the malfunction or error could be so great that it results in venting 100 percent of the gas intended to be captured. Because of this, the commenter states EPA must require recordkeeping so it is aware of these events and overall emissions, and to build an understanding of what causes these errors and how they can be prevented. The commenter recommends EPA finalize Option 1 and require operators of all wells undergoing liquids unloading to maintain records of the number of unloading events that occur, the method used, and any venting that occurred.

Response II-6-87: In the December 2022 Supplemental Proposal, rather than including three separate definitions for well affected facilities (as initially proposed in the November 2021 Proposal) for (1) oil wells with associated gas, (2) gas wells that undergo liquids unloading, and

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<sup>239</sup> 86 Fed. Reg. at 63179.

(3) wells that undergo completions, the EPA proposed a single definition for a well affected facility, which was defined as a single well, in the proposed NSPS OOOOb. In the December 2022 Supplemental Proposal, the EPA proposed that, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured or hydraulically refractured. Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (i.e., in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). See section 6.4.1.2 of this Chapter for specific comments received and EPA’s responses on what constitutes a “modification” for well affected facilities that undergo liquids unloading. While a well affected facility that has been modified (e.g, refractured) would include non-venting liquids unloading events, minimal recordkeeping and reporting requirements would apply to owners or operators of well affected facilities that do not vent during liquids unloading.

For unloading events that result in venting to the atmosphere, the final rule requires owners or operators of well affected facilities/well designated facilities employ best management practices to minimize venting of methane and VOC emissions for each gas well liquids unloading operation, in addition to having to comply with the associated recordkeeping and reporting requirements. Where liquids unloading events were conducted using a technology/technique that eliminates venting to the atmosphere, the final rule only requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. Where unplanned venting occurs from these wells during a compliance period, an owner or operator would be required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events.

See sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and liquids unloading requirements. See section XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

#### 6.4.1.2 Modification – Specific to Liquids Unloading

Comment: Commenters (2218-TCEQ-RRC, 2227-WEA, 2348-EWTC) consider there to be cases where unloading operations would be considered a modification, but do not support this rule to cover all unloading operations.

Commenter (2326-AXPC) requests that EPA remove the overly expansive modification trigger for well liquids unloading.

Commenter (2177-Ute Indian Tribe) notes that the EPA requested comment on whether the following are operational scenarios where a well liquids unloading event could constitute a “modification”:

- (1) the first time, in the life of the well, that well liquids unloading occurs,
- (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs,
- (3) a change in the type or method of well liquids unloading, or
- (4) ongoing liquids unloading as part of a regular operational schedule. The commenter recommends that EPA omit this condition, stating that well liquids unloading events are routine operations of a well and should not constitute a "modification".

Commenter (2218-TCEQ-RRC) agrees with EPA that a modification for well liquids unloading can include (1) the first time, in the life of the well, that well liquids unloading occurs, (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs, or (3) a change in the type or method of well liquids unloading. The commenter contends that ongoing liquids unloading would not be considered a modification, because it is not a physical or operational change to an existing facility.

Commenter (2348-EWTC) notes that intermittent emissions may constitute a modification in the example of liquids being unloaded from storage tank to truck which is captured in “ongoing liquids unloading as part of a regular operational schedule.”

Response II-6-88: As noted by commenters, the EPA requested comment on whether the following are operational scenarios where a well liquids unloading event could constitute a “modification”:

- (1) the first time, in the life of the well, that well liquids unloading occurs,
- (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs,
- (3) a change in the type or method of well liquids unloading, or
- (4) ongoing liquids unloading as part of a regular operational schedule.

While some commenters note that these operations could constitute a modification to a well, others assert that ongoing liquids unloading is routine maintenance and not a physical or operational change to an existing facility and would not constitute a “modification”.

Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (*i.e.*, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). The EPA, for purposes of regulation, has determined that a “modification” of a well does not include (1) the first time, in the life of the well, that well liquids unloading occurs, (2) a change in the type or method of well liquids unloading, or (3) ongoing liquids unloading as part of a regular operational schedule.

While a well affected facility that has been modified (*e.g.*, refractured) would include non-venting liquids unloading events, minimal recordkeeping and reporting requirements would apply to owners or operators of well affected facilities that do not vent during liquids unloading. Comment: Commenters (2172-KOGA, 2179-KIOGA, 2205-Kriebel Well, 2254-PBPA, 2283-Endeavor Energy) do not believe that liquids unloading is an operational change and should not be considered a modification.

Commenter (2254-PBPA), in response to whether the operating scenarios EPA solicited comment on should be considered a modification, PBPA provides the following comments:

- (1) No. Conducting the operation that the facility is designed to conduct should not be considered a modification.
- (2) No. The act of unloading, whether before or after fracturing/refracturing, should not be considered a modification.
- (3) No. A change in the method of well unloading does not necessarily increase emissions or result in additional pollutants being emitted and should, therefore, not be considered a modification, in and of itself.
- (4) No. Such operations are part of regular operations and the life of the well. Precisely because of this, they should not be considered modifications.

Commenter (2254-PBPA) requests that EPA adhere to a plain English definition of “modification.” The commenter contends that an ongoing operation does not meet the commonsense definition of a “modification.” Moreover, they suggest that, given how commonplace liquids unloading is in upstream operations, the first occurrence of a liquids unloading event and ongoing liquids unloading cannot represent a “modification” as that term is generally understood and applied under the CAA’s NSPS.

While the commenter (2254-PBPA), and its members concede that some changes in the type or method of well liquids unloading operations might meet existing CAA requirements for a “modification,” to the extent EPA seeks to regulate these types of changes under any final NSPS for methane emissions from the oil and gas sector, the commenter asserts that the EPA needs to provide clear guideposts to the regulated community. As an example, the commenter notes that, in Texas and New Mexico, changes to liquid unloading operations are considered a modification, only if such changes result in increased emissions. The commenter suggests a similar approach be implemented.

Commenter (2172-KOGA) states that liquids unloading is not an operational change and should not be considered a modification. The commenter contends that the only operational change that could be considered a modification would be when equipment is added to a well to unload liquids. Even then, the commenter explains that most of that will be downhole with an insignificant number of components added to the above ground wellhead, resulting in a wellsite that could still be considered a “single wellhead well site” or a “small wellhead”. The commenter adds that wells that unload liquid and do not vent to the atmosphere should be considered

similarly to EPA's "single wellhead well site" or proposed "small well wellsite" for fugitive emissions surveys utilizing audio, visual or olfactory (AVO) monitoring on a quarterly schedule. The commenter notes that an operator with wells that unload liquid without venting to the atmosphere should not be required to report its unloading events. According to the commenter, many small operators operate wells with plunger lift and other systems that remove liquids from their wells' wellbores without venting. To require those operators to report those unloading events would be a significant burden on those operators, especially with wells that might unload multiple times a day. The commenter adds that EPA's understanding that single well wellheads are not regularly visited is incorrect. In fact, they report that most gas wells operated by small operators that have automated liquid removal systems, whether vented to the atmosphere or not, are regularly visited by the operator's personnel, often daily. The commenter provides that EPA's concern that there might be some type of equipment failure during an automated liquid unloading event resulting in a methane release to the atmosphere can be tempered in that sites with those potential failures are visited very regularly allowing for any failure to be noticed, stopped, and corrected quickly.

The commenter (2179-KIOGA) urges EPA to reconsider its determination that each liquids unloading event represents a modification, making the well subject to new source standards for purposes of liquids unloading standards. The commenter notes that oil and natural gas wells produce the largest volume at the time they are initially drilled; followed by a declining curve over time. Depending on when the liquid unloading event occurs, the production would only return to where it should have been on the declining production curve assuming the liquid unloading event was successful. The production never increases to the volume the wells observed early in the production curve for a new well. Therefore, the commenter asserts that liquid unloading events are considered normal operation for well operators.

Commenter (2205-Kriebel Well) is concerned with the liquid's unloading process that is currently being considered, particularly, "EPA has yet to reach a consensus on whether certain types of liquids unloading events could be all operational change to a well." The commenter states that efficient capture and full payment for our product is critical for the sustainability of the business. Therefore, liquids unloading events do not exceed that which is necessary to produce at marginal wells. The commenter states that through any unloading event, the wells are neither modified nor are their connections to oil and gas bearing reservoirs altered.

Commenter (2283-Endeavor Energy) notes that ongoing liquids unloading does not meet the common-sense definition of a "modification," and given how commonplace liquids unloading is in upstream operations, the first occurrence of a liquids unloading event and ongoing liquids unloading cannot represent a "modification" as that term is generally understood and applied under the CAA. The commenter contends that this reinforces why liquids unloading does not fit properly within the NSPS OOOOb or EG OOOOc framework and should be removed.

Response II-6-89: As noted by commenters, the EPA requested comment on whether the following are operational scenarios where a well liquids unloading event could constitute a "modification":

- (1) the first time, in the life of the well, that well liquids unloading occurs,
- (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs,
- (3) a change in the type or method of well liquids unloading, or
- (4) ongoing liquids unloading as part of a regular operational schedule.

While some commenters note that these operations could constitute a modification to a well, others assert that ongoing liquids unloading is routine maintenance and not a physical or operational change to an existing facility and would not constitute a “modification”.

Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (i.e., in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). The EPA, for purposes of regulation, has determined that a “modification” of a well does not include (1) the first time, in the life of the well, that well liquids unloading occurs, (2) a change in the type or method of well liquids unloading, or (3) ongoing liquids unloading as part of a regular operational schedule.

While a well affected facility that has been modified (e.g, refractured) would include non-venting liquids unloading events, minimal recordkeeping and reporting requirements would apply to owners or operators of well affected facilities that do not vent during liquids unloading.

Comment: Commenter (2433-EDF) notes that in the supplemental proposal, EPA has proposed to revise the “modification” definition for a liquids unloading affected facility to apply to a single well that undergoes hydraulic fracturing or refracturing. Previously, EPA had proposed that a “modification” be defined as a well liquids unloading event. The commenter urges EPA to reconsider this change and notes that they supported the previously proposed definition that a well liquids unloading event constitutes a modification.

Response II-6-90: The EPA requested comment on whether the following are operational scenarios where a well liquids unloading event could constitute a “modification”:

- (1) the first time, in the life of the well, that well liquids unloading occurs,
- (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs,
- (3) a change in the type or method of well liquids unloading, or
- (4) ongoing liquids unloading as part of a regular operational schedule.



While a few commenters note that these operations could constitute a modification to a well, others assert that ongoing liquids unloading is routine maintenance and not a physical or operational change to an existing facility and would not constitute a “modification”.

Based on comments received, the EPA has finalized what was proposed in the December 2022 Supplemental Proposal (*i.e.*, in addition to 40 CFR 60.14, a “modification” of an existing well occurs when an existing well is hydraulically fractured, or hydraulically refractured). The EPA, for purposes of regulation, has determined that a “modification” of a well does not include (1) the first time, in the life of the well, that well liquids unloading occurs, (2) a change in the type or method of well liquids unloading, or (3) ongoing liquids unloading as part of a regular operational schedule.

In addition to liquids unloading being considered routine maintenance for the source category, defining each liquids unloading event as a “modification” would mean that an ongoing/routine liquids unloading operation would constitute a “modification”, which is impractical.

#### ***6.4.2 Proposed Best System of Emission Reduction (BSER)***

##### **6.4.2.1 Proposed Well Liquids Unloading Requirements**

Comment: Commenters (2258-MS, 2446-IPAA) states that the proposed regulation, as it pertains to wells that do not vent during liquids unloading, seems more like an Information Collection Request (ICR) than a regulation to control emissions. The commenters recommend EPA develop regulations specific to each type of liquid unloading technique and that EPA ensure regulations are consistent with the other forms of regulations associated with the equipment and techniques that could be part of these unloading activities. The commenters assert that if EPA requires further understanding of these techniques, they should not use this regulation to acquire such information by requiring significant reporting burdens for activities with no emissions.

Response II-6-91: See sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and liquids unloading requirements. For unloading events that result in venting to the atmosphere, the final rule requires owners or operators of well affected facilities/well designated facilities employ best management practices to minimize venting of methane and VOC emissions for each gas well liquids unloading operation, in addition to having to comply with the associated recordkeeping and reporting requirements. Where liquids unloading events were conducted using a technology/technique that eliminates venting to the atmosphere, the final rule only requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. Where unplanned venting occurs from these wells during a compliance period, an owner or operator would be required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events.

See section XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenter (2326-AXPC) states that EPA’s proposed BSER is to have no emissions to the atmosphere and that non-emitting equipment or activities be subject to what they contend are burdensome recordkeeping and reporting requirements that would have no corresponding environmental benefit. The commenter provides that the issue is whether CAA section 111(b) and/or CAA 111(d) authorize EPA to set performance standards that ensure the intended regulatory target is not a “stationary source.” The commenter notes that the CAA’s standards of performance – both CAA sections 111(b) and (d) – provide EPA authority to regulate categories of “stationary sources,” and define a stationary source as “any building, structure, facility, or installation which emits or may emit any air pollutant.”<sup>240</sup> The commenter contends that this plain language of the statute requires that a stationary source emit, or have the potential to emit, to the atmosphere. While “stationary source” may apply as broadly as an entire well site, for example, EPA’s historic implementation of CAA section 111(b) has been to more narrowly regulate “affected facilities” – typically a type of equipment or activity – which the commenter believes fits within CAA section 111’s definition of stationary source. The commenter suggests that, given the statute’s plain language, it is outside of EPA’s authority to regulate non-emitting equipment or activities under CAA section 111 because any such equipment or activity is not a “stationary source.”

The commenter (2326-AXPC) provides that EPA proposes BSER that would result in no VOC or methane emissions from gas well liquids operations. Thus, compliance with EPA’s proposed BSER ensures that gas well liquids operations are not “stationary sources” because compliance will not, and could not, result in emissions. The commenter maintains that this exceeds EPA’s authority granted under CAA section 111.

Response II-6-92: See sections X.F.1 and 3 of the preamble to the final rule which details EPA’s final standards related to well affected facilities/designated facilities and liquids unloading requirements. Where liquids unloading events were conducted using a technology/technique that eliminates venting to the atmosphere, the final rule only requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. Where unplanned venting occurs from these wells during a compliance period, an owner or operator would be required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events. See section XI.F.1 and 3 of the preamble to the final rule for the basis for any changes made from the December 2022 Supplemental Proposal and final rule related to liquids unloading as an outgrowth of significant comments.

Comment: Commenters (2348-EWTC, 2383-Baker Hughes (BH)) state that there are significant opportunities to reduce emissions associated with liquids unloading despite the diversity of circumstances and technologies involved.

Commenter (2348-EWTC) provides that one means of facilitating reductions in methane emissions generated by liquids unloading is to deploy advanced methods that reduce the frequency of unloading events. For example, there are artificial lift solutions that use advanced analytics and “smart” edge technology to boost production and reduce associated methane emissions from oil and gas wells. The commenter notes that during one recent three-month pilot

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<sup>240</sup> 42 U.S.C. §7411(a)(3) (emphasis added).

project in the Haynesville Shale using one artificial lift solution across 10 wells, the operator's gas production increased by 5 percent and well unloading events decreased by 94 percent. The commenter believes BMPs should include technologies that reduce the frequency of events as a means of reducing overall emissions.

Commenter (2383-BH) describes ProductionLink™ Edge, an integrated production optimization platform providing real-time transmission and monitoring of artificial lift operational data. In 2021, natural gas producer Vine Energy deployed ProductionLink™ Edge across 100 natural gas wells in Louisiana's Haynesville Shale. This follows a three-month joint pilot project in Haynesville Shale using the artificial lift solution across 10 wells, during which Vine's gas production increased by 5 percent and well unloading events decreased by 94 percent, which in turn reduced methane emissions. The commenter notes that 40 CFR 60.5376b(d) and 60.5390c(d) define the minimum requirements for a BMP plan to minimize venting of methane and VOC emissions from liquids unloading events for operators seeking an exemption from the zero-emission standard defined in 40 CFR 60.5376b(b) and 60.5390c(b). The commenter recommends that, given the commercial availability of ProductionLink™ Edge and other such solutions, EPA include the following to the list of the requirements at 40 CFR 60.5376b(d) and 60.5390c(d).

- (5) Document technology and operating practices employed to reduce the need and frequency of liquids unloading events at a well affected facility.

The commenter (2383-BH) states that production optimization represents a BMP for capable of delivering cost-effective efficiency improvements and significant methane and VOC emission reduction.

Response II-6-93: The EPA appreciates the feedback and information provided by commenters. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

#### 6.4.2.2 Zero Emissions Standard

Comment: Commenters (2218-TCEQ, 2248-NDPC, 2283-Endeavor Energy, 2326-AXPC, 2428-API) are concerned with the feasibility and burden a zero-emission standard would have on oil and gas operations.

Commenter (2218-TCEQ) asserts that the proposed rule's zero emission limit is an extremely costly and potentially unrealistic standard for rural gas well sites with typical well liquids loading and unloading operations to meet (since it may not be possible to eliminate the emission of every loading and unloading methane molecule). To achieve compliance with this standard, the commenter anticipates that industry would have to install expensive vacuum inducing, vapor tight loading, and potentially vapor tight disconnection equipment at each Texas gas well site that loads liquids (and may still not be able to eliminate every molecule of potential methane emissions). The commenter recommends that EPA consider the economic feasibility in

establishing a 40 CFR 60.5390c control limit and replace the zero-emission standard with a more cost-effective and realistic one.

Commenter (2248-NDPC) states that, as they communicated to EPA in their comments on the November 2021 proposal, well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While the commenter supports EPA's inclusion of well liquid unloading operations as an affected facility, the commenter asserts that the regulation should be based solely on the work practice standard outlined in 40 CFR 60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in 40 CFR 60.5376b(b).

Commenter (2283-Endeavor Energy) states that liquids unloading is a daily occurrence for many operators and the proposal's requirements simply ignore the realities of these operations and are therefore arbitrary and capricious. The commenter notes that EPA proposes a zero-emission standard for liquids unloading at existing wells. Where it is technically infeasible or not safe to meet the zero-emission standard, EPA proposes to require that owners and operators employ best management practices to minimize venting. The commenter provides that they would need to install closed loop systems, low-pressure flares, or another control device to meet the zero-emission standard for liquids unloading at well sites and expect that many other producers in the Midland Basin would have to do the same. The commenter considers these kinds of capital expenses and retrofitting of sites-particularly at existing well sites-can fundamentally change the economics of the site. The commenter recommends that EPA remove this requirement entirely, or at the very least remove it from any finalized EGs so that it does not apply to existing sites.

Commenter (2326-AXPC) requests removal of the zero emissions standard and associated recordkeeping and reporting requirements such that NSPS OOOOb/EG OOOOc standards apply only where the operator intends that a gas well liquids unloading operation will result in methane and/or VOC emissions to atmosphere. The commenter contends that excluding non-emitting gas well liquids unloading activities from regulation would not impact the standards for those unloading events that emit to atmosphere.

Commenter (2428-API) does not support the provisions proposed in 40 CFR 60.5376b(b) establishing a zero-emission limit on liquid unloading operations. They believe that a zero-emission limit creates an undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. The commenter states that this undue burden is compounded when considering the logistical and practical implementation of the associated proposed recordkeeping, reporting and certification statements.

Response II-6-94: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments. Specifically, see section XI.F.3.a response to this and other comments received on EPA's proposed December

2022 Supplemental zero-emissions standard and section XI.F.3.b on EPA's proposed December 2022 Supplemental recordkeeping and reporting requirements.

Comment: Commenter (2326-AXPC) suggests that, by defining well liquids unloading events to mean only those wellbore liquid removal events that are intended vent to atmosphere, EPA would avoid regulating events or operations that do not have any emissions to atmosphere. The commenter believes that such a framework is much more consistent with EPA's legal authority – which does not extend to equipment or operations that do not have emissions releases. In connection with this creation of a definition for well liquids unloading event, the commenter recommends that the EPA eliminate use of the term zero emissions or zero emissions standard in reference to wellbore liquids removal. The commenter notes that API recommends removal of the requirement to demonstrate that an operator cannot preclude venting to the atmosphere.<sup>241</sup> The commenter supports that position. However, the commenter states that, if EPA retains those requirements, then EPA should only require: (1) maintaining documentation that the operator cannot preclude venting to the atmosphere due to technical, safety or economic considerations; and (2) the implementation of BMPs where that demonstration has been made. Importantly, the commenter expresses that they believe that wellbore liquids removal operations that are routed to combustion device or a flare do not “vent to atmosphere.” In fact, routing emissions from wellbore liquids removal operations to a combustion device or a flare may (in certain circumstances) be the best mechanism to reduce emissions from well liquids unloading. By using the term “zero emissions,” which EPA has indicated in other contexts that combustion devices do not fall into, they believe that the EPA has limited the value and usefulness of this control methodology. Thus, the commenter contends that wellbore liquids removal operations that are routed to a combustion device should not be considered to be venting to the atmosphere, and under their suggested proposal, would not be considered well liquids unloading. The commenter recommends that EPA clarify in the final rule that well liquids unloading being routed to a control device is not intended to vent and thus not subject to the well liquids unloading requirements.

Response II-6-95: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments. Specifically, see section XI.F.3.a response to this and other comments received on EPA's proposed December 2022 Supplemental Proposal zero-emissions standard and section XI.F.3.b on EPA's proposed December 2022 Proposal Supplemental recordkeeping and reporting requirements.

Comment: Commenter (2446-IPAA) states EPA needs to define more clearly what would be considered "zero emitting". According to the commenter, routing of vented emissions to a flare or a control device should be considered zero-emitting in this context as it is often the best solution for emission reduction.

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<sup>241</sup> API Supplemental Proposal Comments Section 9.3.

Response II-6-96: The EPA disagrees that routing vented emissions to a flare or a control device should be considered zero-emitting. Flare/control devices are not zero-emitting (*i.e.*, do not control 100 percent of the vented emissions on a continuing basis and flares/combustors create secondary emissions).

The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. Additionally, the final standards/presumptive standards have been revised to allow owners or operators the option to comply with the GHG and VOC standards by reducing methane and VOC emissions from each gas well liquids unloading event by 95 percent by routing emissions to a control device via a closed vent system (CVS). See Volume I of this Response to Comment Document, Chapter 12, Response I-12-20 for a response to comments requesting this option.

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards. See also section XI.F.3.a response to comments received on EPA's proposed December 2022 Supplemental Proposal zero-emissions standard.

Comment: Commenter (2177-Ute Indian Tribe) requests that an exception to the zero emissions standard be allowed for smaller producing wells where compliance with the zero-emission standard for gas well liquids unloading would be uneconomic to the point of it being less expensive to shut-in the well.

Response II-6-97: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments.

The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section XI.F.3.a response to this and other comments received on EPA's proposed December 2022 Supplemental Proposal zero-emissions standard and section XI.F.3.b on EPA's proposed December 2022 Proposal Supplemental recordkeeping and reporting requirements.

#### 6.4.2.3 Certification of Non-Zero Emitting Liquids Unloading Method

Comment: Commenters (2258-MS, 2294-OOGA, 2326-AXPC, 2428-API, 2446-IPAA) request EPA include economic feasibility in addition to the technical and safety reasons described in the proposal.

Commenter (2258-MS) asserts that the proposed certification language needs to include not only technical and safety reasons but should also include economic feasibility as well, as follows:

I certify that the technical, economic and safety infeasibility justification of needing to use a non-zero emitting liquids unloading method for all liquids unloading events at the well-affected facility was prepared under my direction or supervision. Based on my professional knowledge and experience, and inquiry of personnel involved in the infeasibility justification, the certification submitted herein is true, accurate, and complete.

Commenter (2294-OOGA) notes that the preamble to the supplemental proposal allows for economic feasibility determinations when utilizing liquids unloading methods that vent to the atmosphere: “Additionally, for wells that utilize methods that vent to the atmosphere, the proposed rule would require: “(1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons.”<sup>242</sup> However, the commenter points out that the rule text makes no mention of economic feasibility, limiting infeasibility determinations to technical and safety-related justifications. The commenter provides that this apparent limitation on feasibility determinations in the rule text is unreasonable and renders the infeasibility demonstration impractical. According to the commenter, a technical feasibility review can take a significant amount of time to complete. The review time would result in lost production due to the well having to be shut in. For an operator to keep pace with required well unloads, significant additional staffing would be needed to complete the required reviews. Additionally, the commenter provides that there are very few scenarios that an engineer or qualified professional would certify a technical or safety infeasibility justification. Without a certified justification and allowance for unloading without a zero emissions method, wells would ultimately just be shut in until the well rebuilt pressures to produce on its own, resulting in lost production or the well never returning to production. The commenter urges EPA to revise the rule text to include economic infeasibility as a justification for needing to use a non-zero emitting liquids unloading method. The commenter maintains that this would provide necessary additional opportunities for justifying the use of a non-zero emitting liquids unloading method, especially for low producing wells.

Commenters (2258-MSD, 2446-IPAA) recommend EPA provide additional supporting documentation about what would be considered acceptable “written justification”. Commenters point out that EPA does not provide examples of what level of detail a certifier should use, provides no minimum set of requirements, no specific economic input criteria, and has created a level of ambiguity regarding this very exacting statement. The commenters add that professional engineers or another qualified individual with expertise in liquids unloading operations will be reluctant to provide such a statement without more specificity about the criteria for such a statement. If EPA cannot provide such detail, the commenters contend that there will be considerable challenges within the industry for qualified certifiers and this requirement should therefore be withdrawn.

Commenter (2326-AXPC) requests EPA revise the language in the regulations to be consistent with its preamble. In the preamble, EPA states that: “for wells that utilize methods that vent to the atmosphere, the proposed rule would require: (1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety or economic reasons....” However, the commenter notes that EPA does not include “economic” considerations in the rule

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<sup>242</sup> 87 FR 74782.

language. The commenter notes that the rule language currently references only “technical or safety reasons.” Consistent with EPA’s preamble, the commenter states EPA should revise the rule to reference “technical, safety, or economic reasons.” The commenter also provides that inclusion of “economic” is also critical considering the framework for the NSPS.

Commenter (2428-API) states one of the legal flaws in EPA’s opt-out scheme is that technical feasibility is the only governing criterion. The commenter provides that the cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA section 111 standards of performance. The commenter contends that this flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Response II-6-98: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. As discussed under section X.F.3.a of the final rule preamble states, the EPA has determined that the intermittent and necessary nature of the variable methods and technologies employed to unload liquids and the unpredictable nature as to when it may be necessary to vent emissions makes a work practice standard more practical for liquids unloading operations than a zero-emissions standard. As a work practice standard, the engineering certification statement required under the December 2022 Supplemental Proposal that required an explanation of why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons is unnecessary and has been removed from the final rule.

Comment: Commenters (2172-KOGA, 2403-PAO, 2428-API) provide comments regarding who would conduct the technical infeasibility analysis, particularly given the concerns of certification via a professional engineer.

Commenter (2172-KOGA) states that EPA’s proposed requirements for wells with liquid unloading operations that do vent to the atmosphere are to 1) document “why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons”, 2) BMP to minimize venting, 3) documenting BMPs were followed, and 4) submission of an annual report that includes the number of unloading events during the year and the number of events that “did not follow the BMPs” are justifiable as long as the EPA does not require any documentation or BMP’s to be compiled by a “Registered Professional Engineer”. The commenter contends that the operator of a well that vents to the atmosphere while liquids are unloaded should be allowed to document “why it is infeasible to utilize a non-venting method” of liquid unloading for their own well. Small wells, producing 10 thousand cubic feet (Mcf)/day or less that need to be bailed once every year or two to remove fluid built up over the pay zone, cannot afford to have a professional engineer sign off on its liquid unloading methodology, especially since it has probably been done the same way for the last several decades. The commenter is concerned that this would be a heavy economic burden on operators of legacy producing properties and other low-cost operations.

Commenter (2403-PAO) states that the technical infeasibility analysis demonstrating that well liquids unloading cannot be achieved with zero emissions can be conducted by a qualified



professional engineer or an in-house engineer. The commenter requests EPA clarify that technical infeasibility for liquids unloading can be accomplished by a professional engineer or an inhouse engineer.

Commenter (2428-API) contends that the express threat of possible personal liability on the part of certifiers will limit the number of individuals willing to make the needed certifications, particularly considering the uncertainties about what will be needed as a practical matter to demonstrate “technical infeasibility.” The commenter adds that the clear opportunity and possibility of second guessing will be further material disincentives.

Response II-6-99: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. As discussed under section X.F.3.a of the final rule preamble states, the EPA has determined that the intermittent and necessary nature of the variable methods and technologies employed to unload liquids and the unpredictable nature as to when it may be necessary to vent emissions makes a work practice standard more practical for liquids unloading operations than a zero-emissions standard. As a work practice standard, the engineering certification statement required under the December 2022 Supplemental Proposal that required an explanation of why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons is unnecessary and has been removed from the final rule.

#### 6.4.2.4 Best Management Practices (BMPs)

Comment: Commenter (2428-API) supports the proposed alternative measures outlined in 40 CFR 60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on BMPs that achieve the intent to reduce emissions from liquid unloading of gas wells. The commenter believes that these provisions should be considered BSE and should not be considered an exception to the standard as currently proposed in 40 CFR 60.5376b(c).

The commenter (2428-API) appreciates EPA’s recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The commenter contends that the work practice standards proposed in 40 CFR 60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

Response II-6-100: The comment is a supportive comment of the December 2022 Proposal for best management practices. The EPA has maintained the best management practice requirements proposed in the December 2022 Supplemental Proposal. For unloading technologies or techniques that result in venting to the atmosphere, the final rule requires that owners or operators employ best management practices that meet minimum specified criteria to minimize venting of methane and VOC emissions for each gas well liquids unloading operation. Unloading

events that employ non-venting liquids unloading technologies and techniques that do not result in venting of methane and VOC emissions to the atmosphere are not subject to best management plan requirements and the associated recordkeeping and reporting requirements under the rule. An owner or operator of a well affected facility that employs non-venting liquids unloading technologies and techniques is only required to comply with minimal recordkeeping and reporting requirements. In instances where there may be an unplanned venting event, that event would be subject to the best management practices to minimize venting of emissions and the associated recordkeeping and reporting requirements.

Additionally, the EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rule related to liquids unloading as an outgrowth of significant comments. Specifically, see section XI.F.3.a response to this and other comments received on EPA's proposed December 2022 Supplemental zero-emissions standard.

Comment: Commenter (2433-EDF et al) recommends that EPA limit permissible circumstances in which liquids unloading can be conducted without zero emissions and require rigorous documentation of why venting had to occur. The commenter notes that the EPA has proposed allowing venting if "it is technically infeasible or not safe to perform liquids unloading with zero emissions," in which "an owner or operator [must] establish and follow [best management practices] to minimize methane and VOC emissions during liquids unloading events to the extent possible."<sup>243</sup> EPA does not intend to "dictate all of the specific practices that must be included," but rather "would specify minimum acceptance criteria required for the types and nature of the practices."<sup>244</sup> The commenter contends that this is too nebulous and is likely to result in regular venting, followed by operators checking off a handful of best practices. The commenter suggests that EPA should instead clearly define best practices, list them in hierarchical order, and require operators to follow the practices or otherwise provide rigorous documentation as to why they could not do so.

Response II-6-101: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and XI.F.1 and 3 for the basis for any changes made from the December 2022 supplemental proposal and final rules related to liquids unloading as an outgrowth of significant comments. Specifically, see section XI.F.3.a response to this and other comments received on EPA's proposed December 2022 Supplemental zero-emissions standard. The EPA has determined that, because of the intermittent and necessary nature of allowing for variable methods and technologies employed to unload liquids, and the often-unpredictable timing as to when owners and operators may need to vent emissions, a work practice standard is more appropriate than an emissions standard for liquids unloading operations. Because of the varied

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<sup>243</sup> 86 Fed. Reg. at 63179.

<sup>244</sup> Id.

techniques or technologies that could be employed and the differing circumstances that could exist for a well affected/designated facility, the EPA continues to not dictate specific best practices and has maintained the proposed December 2022 Supplemental Proposal minimum criteria to be included in a BMP plan and implemented to meet the final standards/presumptive standards:

- (1) Include steps that create a differential pressure to minimize the need to vent a well to unload liquids,
- (2) Include steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,
- (3) Unload liquids through the separator where feasible, and
- (4) Close all wellhead vents to the atmosphere and return the well to production as soon as practicable.

See section XI.F.3.a response to comments on EPA’s proposed December 2022 Supplemental Proposal zero-emissions standard and section XI.F.3.b on EPA’s response to comments on EPA’s proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

#### ***6.4.3 Liquids Unloading Definition***

Comment: Commenter (2428-API) states that additional clarification to the proposed definition of liquids unloading is warranted. The commenter provides that other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state GHG inventories from well liquids unloading. The commenter requests EPA explicitly provide clarification to address these distinctions, within the definition for “liquids unloading” so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed. The commenter provides suggested clarifications to the definition of liquids unloading under 40 CFR 60.5430b and 40 CFR 60.5430c is as follows (underlined text indicates new text):

*Liquids unloading* means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.

Response II-6-102: The commenter’s suggested clarifying language edits to the “liquids unloading” definition meet EPA’s intent and the suggested clarifying edits have been made to 40 CFR 60.5430b and 40 CFR 60.5430c.

#### ***6.4.4 Recordkeeping and Reporting Requirements***

Comment: Several commenters (2227-WEA, 2238-SOOGA, 2294-OOGA, 2326-AXPC, 2391-Chesapeake Energy, 2428-API) request that EPA not require recordkeeping and reporting of non-venting liquids unloading events.

Another commenter (2258-MSC) requests the removal of reporting requirements that do not provide valuable emissions-related information.

Response II-6-103: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and section XI.F.3.a of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

Comment: Commenter (2428-API) recommends that proposed recordkeeping and reporting for liquids unloading operations be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere. The commenter notes that the information proposed by EPA within 40 CFR 60.5420b and 40 CFR 60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, the commenter suggests EPA define the data operators, track per unloading operation, and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. The commenter provides that these suggestions assume that liquid unloading operations are to be conducted using a work practice standard.

Furthermore, commenter (2428-API) provides that the current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, the commenter states that the EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in 40 CFR 60.5420b(c)(2)(ii)(B) and 40 CFR 60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. The commenter notes that this may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, the commenter states that a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The commenter considers the justification provisions in 40 CFR 60.5420b(c)(2)(ii)(B) to be untenable when the same technique used on a well may result in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The commenter asserts that the fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes as little as

30 minutes, to safely perform the liquid unloading operation. The commenter therefore requests:

1. EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure.
2. Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

The commenter (2428-API) recommends that EPA streamline and simplify the recordkeeping and reporting for liquid unloading operations as follows:

For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:

- US Well ID
- The number of liquids unloading events during the year that resulted in emissions.
- The date and time of each liquid unloading operation where venting occurred.
- The duration of venting in hours.
- Reason venting occurred.

Additionally, the commenter (2428-API) requests that recordkeeping for liquid unloading operations include the following:

Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).

Response II-6-104: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and section XI.F.3.a of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

With regards to the commenter that requests that recordkeeping for liquid unloading operations include documentation of the best management practices plan, the December 2022 Supplemental Proposal included this language in 40 CFR 60.5420b and 40 CFR 60.5420c, and it is maintained in the final rule, with the exception that the cited language is 40 CFR 60.5376b(c) [not 40 CFR 60.5376b(d)] in NSPS OOOOb, and 40 CFR 60.5390c(c) in EG OOOOc.

Comment: Commenter (2248-NDPC) also requests that the recordkeeping and reporting requirements be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting

may occur. They also add that the applicability for liquid unloading operations must be designated as the date of the supplemental proposal as the recordkeeping requirements were not explicitly known for each event that occurred prior to the publication. The commenter notes that much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal. According to the commenter, operators should not be penalized for failing to have records and certification statements for events that occurred before the particular data elements were made known as being required.

Response II-6-105: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard.

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and section XI.F.3.b of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

Comment: Commenter (2326-AXPC) argues that the EPA should not require recordkeeping or reporting for each well liquid unloading operation conducted during the year unless EPA has defined well liquid unloading operation to mean only those well liquid unloading operations intended to vent to atmosphere. As the commenter noted in their comments on the November 2021 proposal, they continue to support EPA's original "Option 2" and feel strongly that EPA's Option 1 (selected in the December 2022 Supplemental Proposal by EPA) has significant practical and legal implications. As EPA recognizes in its supporting documentation, the commenter reports that one primary methodology that may be used to reduce or eliminate venting from removal of liquids of gas wells is a plunger lift. In most operational scenarios, a plunger lift will assist with liquid removal from the wellbore without any venting to the atmosphere. The plunger lift will operate on either a set cycle or may operate based upon pressures reflected in the well bore. However, not all plunger lifts are designed to or have the necessary equipment on site to track each cycle of the plunger lift. Thus, the commenter explains that the EPA's proposal could require installation of equipment to track the plunger cycles while providing no emissions reductions benefits. The commenter notes that the EPA has not fully evaluated the cost of installing and operating such tracking equipment in its cost-benefit analysis, and given that there will be no emissions benefits, EPA cannot show that such a requirement would be cost-effective. They note that this is only one example. The commenter adds that even where equipment is available to track the number of wellbore liquids removal events that do not vent to atmosphere, the operational costs of undertaking that tracking are considerable and the data collected will be significant. According to the commenter, EPA has provided no reasonable explanation for its need to obtain and track data relating to the number of wellbore liquids removal events that do not vent to atmosphere. And EPA provides virtually no explanation for its decision to stick with Option 1, other than the fact that "malfunctions" can result in vented emissions from liquids removal operations that would otherwise meet the zero emissions standard. The commenter states that the EPA has no basis for concern with respect to malfunctions as it has implemented a robust AVO and optical gas imaging (OGI) inspection

program that would be expected to identify wells that have emissions during liquids removal that were not expected or intended.

The commenter (2326-AXPC) concludes that one simple solution to this problem is to define well liquids unloading to mean only those wellbore liquids removal events that are intended to vent to atmosphere. By defining well liquids unloading in such a manner, the commenter believes that the EPA would not only encourage operators to find solutions that eliminate venting and will ensure that operators not only implement certain emission reduction requirements to reduce venting to atmosphere but would also record and report on those instances that do result in venting to the atmosphere.

Response II-6-106: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard.

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and section XI.F.3.b of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

Comment: Commenter (2446-IPAA) cites the EPA referenced study by Dr. Allen, University of Texas, Environmental Science & Technology, December 9, 2014, *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings*, "[s]ome wells with plunger lifts are automatically triggered and unload thousands of times per year." The commenter states that just a single well with thousands of unloading events per year, would create a significant reporting burden, and when wells do not vent this reporting should not be required.

Response II-6-107: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. Where liquids unloading events were conducted using a technology/technique that eliminates venting to the atmosphere, the final rule only requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. Where unplanned venting occurs from these wells during a compliance period, an owner or operator would be required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events.

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and section XI.F.3.b of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal recordkeeping and reporting requirements.

Comment: Commenter (2214-(BlueCrest)) suggests that the following citation be checked for correct cross referencing: 40 CFR 60.5420b(c)(2)(ii)(B).

Response II-6-108: 40 CFR 60.5420b(c)(2) has been revised and the cross- reference issue identified by the commenter is not included in the final rule.

#### ***6.4.5 Existing State and Federal Requirements***

Comment: Commenter (2227-WEA) believes that natural gas well liquids unloading operations subject to emission standards promulgated by a state or local authority should be excluded from federal regulation. For example, and as acknowledged by EPA, Colorado Air Quality Control Commission Regulation No. 7, Part D, Section II.G.1.d., Title 20, Chapter 2, Part 50 of the New Mexico Administrative Code (20.2.50.117 NMAC) and other state and local regulations include emission standards for natural gas well liquids unloading operations. The commenter notes that both New Mexico and Colorado only require recordkeeping and reporting associated with unloading events involving the release of emissions.

Additionally, the commenter (2227-WEA) notes that the proposed rules provide procedures for the submittal and approval of alternative means of emission limitation (AMEL) for complying with fugitive emissions standards based on programs under state, local, or tribal authorities for the fugitive emissions components affected facility. The commenter recommends that EPA, at a minimum, should apply a similar procedure to natural gas well liquids unloading operations which are also regulated by some states. However, the commenter states that the current AMEL process is overly burdensome and time-consuming, and a categorical exclusion should be codified in the final standards for affected facilities currently subject to certain state and local regulations. The commenter concludes that future regulations promulgated by a federal, state, or tribal authority would be subject to the AMEL process.

Response II-6-109: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. Under the final standards/presumptive standards Where liquids unloading events were conducted using a technology/technique that eliminates venting to the atmosphere, the final rule only requires owners and operators to report the identification of the well along with the non-venting technology or technique used in their annual report. Where unplanned venting occurs from these wells during a compliance period, an owner or operator would be required to follow their best management practices plan for such events and comply with the associated recordkeeping and reporting requirements for those events.

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and sections XI.F.1 and 3 of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal zero emissions standard/presumptive standards and recordkeeping and reporting requirements.

The EPA disagrees with the commenter that a categorical exclusion should be codified in the final standards for affected facilities currently subject to certain state and local regulations. The EPA reviewed both the New Mexico and Colorado requirements when developing the final standards/presumptive standards for liquids unloading operations. While, for example, both New



Mexico and Colorado only require recordkeeping and reporting associated with unloading events involving the release of emissions, the final NSPS OOOOb and EG OOOOc standards/presumptive standards also require minimal recordkeeping and reporting where a technology/technique is used that eliminates venting to the atmosphere. Under the final rule requirements, an owner or operator needs to report the identification of the well along with the non-venting technology or technique used in their annual report.

An owner or operator also has the option to follow the procedures of 40 CFR 60.5399b for the submittal and approval of AMEL for complying with the GHG and VOC NSPS OOOOb work practice standards for liquids unloading operations. Additionally, states can consider RULOF to support the need for alternative compliance options under EG OOOOc in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Comment: Commenter (3839-AOGA) reports that the Alaska Oil and Gas Conservation Commission (AOGCC) and the Bureau of Land Management (BLM) implement regulatory requirements which diminish or eliminate venting during liquids unloading events. The commenter requests that EPA revise its proposal to deem that Alaska's operators meet the proposed control requirements under NSPS OOOOb when operators have satisfied requirements under the AOGCC and BLM. The commenter explains that there is precedence for AOGA's request. They refer to the notification, reporting, and recordkeeping requirements found at 40 CFR 60.5420a(2)(ii), which states, "if an operator is subject to state regulations that require advanced notification of well completions, and the [operator] has met those requirements, then the [operator] is considered to have met the advanced notification requirements of the rule." Similarly, the commenter urges that the EPA's rule be revised to state, "if an operator is subject to state regulations for venting during liquids unloading, and the operator has met those requirements, then the operator is considered to have met the control requirements under Subpart OOOOb." According to the commenter, revising the EPA's proposal in this suggested manner will allow the EPA to meet its venting and flaring goals while avoiding duplicative regulatory schemes where no environmental benefits would result.

Response II-6-110: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and sections XI.F.1 and 3 of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Proposal Supplemental Proposal zero emissions standard/presumptive standards and recordkeeping and reporting requirements.

The EPA disagrees that the NSPS OOOOb should be revised to deem that Alaska's operators meet the proposed liquids unloading requirements under NSPS OOOOb when operators have satisfied requirements under the AOGCC and BLM. However, an owner or operator may follow the procedures of 40 CFR 60.5399b for the submittal and approval of AMEL for complying with the GHG and VOC NSPS OOOOb work practice standards for liquids unloading operations. Additionally, states can consider RULOF to support the need for alternative compliance options

under EG 0000c in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Comment: Commenter (2220-Wyoming Department of Environmental Quality (WDEQ)) reports that much of Wyoming's mineral estate is managed by federal agencies such as the BLM. Wyoming receives significant revenue from severance and other taxes paid on oil and gas production. In the supplemental proposal, the commenter states that the EPA expanded its proposed NSPS 0000b standards pertaining to well liquids unloading operations to include zero VOC and methane emissions requirements for liquid unloading to EG 0000c for existing wells. According to the commenter, these requirements conflict with existing BLM regulations that require direct measurement of liquids from tanks. The commenter states that it is technically infeasible for operators to undertake these direct measurements, which involve opening thief hatches, while maintaining a zero-emission standard. Furthermore, they add that there are technical safety concerns pertaining to zero-emissions liquid unloading involving scenarios where oxygen could get into the tank. Although EPA does include a provision that, in the event of technical infeasibility, an owner or operator would establish and follow BMPs to minimize methane and VOC emissions, the commenter states that these potentially conflicting requirements nevertheless could discourage operators from undertaking production on federal lands in Wyoming. The commenter asserts that the EPA needs to consult with BLM about the supplemental proposal, and EPA should ensure the two agencies' regulations do not conflict.

Commenter (2220-WDEQ) provides that Wyoming already imposes stringent, 98-percent control requirements for well liquids unloading operations and the state would be disproportionately impacted if the EPA discourages production on federal lands by imposing onerous new regulations. A significant amount of oil and gas production occurs on federal lands in Wyoming. Between 2003 and 2019, Wyoming has consistently ranked second in the nation in federal oil production, trailing only New Mexico. Over the same timeframe, they report that Wyoming has been the national leader in federal natural gas production by a wide margin.<sup>245</sup> Two-thirds of the state's natural gas is produced on federal lands leased by energy companies.<sup>246</sup> As such, they contend that there are potential negative ramifications for Wyoming's economy if the proposed rule discourages production on federal lands.

The commenter (2220-WDEQ) argues that the proposed NSPS 0000b and EG 0000c standards ultimately could result in operators reconsidering locating in Wyoming and instead locating in states that would not experience similar conflicting technical requirements because the majority of their production does not take place on federal lands. In addition to Wyoming's state-level concerns, they note that it is also worth pointing out that the federal government also could see its mineral revenues impacted if operators choose to relocate from federal lands. The commenter urges the EPA to reconsider how its zero-emission requirements conflict with BLM's

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<sup>245</sup> "The Fiscal and Economic Impacts of Federal Onshore Oil and Gas Lease Moratorium and Drilling Ban Policies." Dr. Timothy J. Considine, Professor of Energy Economics, School of Energy Resources, University of Wyoming. Dec. 14, 2020. <https://www.wyoenergy.org/wp-content/uploads/2020/12/Final-Report-Federal-Leasing-Drilling-Ban-Policies-121420.pdf>.

<sup>246</sup> U.S. Energy Information Administration, Wyoming State Profile and Energy Estimates, <https://www.eia.gov/state/analysis.php?sid=WY>.

direct measurement requirements before promulgating its final rule and consider including an exemption for operators located on federal lands.

Response II-6-111: The EPA has not finalized its December 2022 proposal to require owners and operators to employ techniques or technologies that eliminate methane and VOC emissions, unless it was technically infeasible or not safe to meet the zero emissions standard. For unloading technologies or techniques that result in venting to the atmosphere, the final rule requires that owners or operators employ best management practices that meet minimum specified criteria to minimize venting of methane and VOC emissions for each gas well liquids unloading operation. Unloading events that employ non-venting liquids unloading technologies and techniques that do not result in venting of methane and VOC emissions to the atmosphere are not subject to best management plan requirements and the associated recordkeeping and reporting requirements under the rule. An owner or operator of a well affected facility that employs non-venting liquids unloading technologies and techniques is only required to comply with minimal recordkeeping and reporting requirements. In instances where there may be an unplanned venting event, that event would be subject to the best management practices to minimize venting of emissions and the associated recordkeeping and reporting requirements. The EPA believes that the final work practice standard and associated recordkeeping and reporting requirements will incentivize owners or operators of well affected facilities and well designated facilities to minimize or eliminate the venting of emissions to the maximum extent possible during liquids unloading events.

Based on changes made in the final NSPS OOOOb standards and EG OOOOc presumptive standards for liquids unloading operations, any conflicts with the December 2022 Supplemental Proposal zero emissions standard because of other rule requirements that could result in some venting to the atmosphere from a well affected facility conducting liquids unloading would be resolved. Additionally, states can consider RULOF to support the need for alternative compliance options under EG OOOOc in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

See section X.F.1 and 3 of the preamble to the final rule for details on EPA's final standards/presumptive standards and sections XI.F.1 and 3 of the preamble to the final rule for EPA's response to comments on EPA's proposed December 2022 Supplemental Proposal zero emissions standard/presumptive standards and recordkeeping and reporting requirements.

## **6.5 Technical Infeasibility**

Comment: Commenter (2428-API) states the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches are “technically infeasible.” The commenter notes that there is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is “infeasible” based solely on a technical assessment of whether it can

theoretically be physically applied in the given situation. So, for example, the commenter suggests that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. The commenter believes that this outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

Should EPA retain the requirement for case-specific certifications, commenter (2428-API) requests that EPA revise the required certification. The proposed regulatory text of each certification includes the following sentence: “Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”<sup>247</sup> The commenter requests that this be revised to specify that the certification is based on “reasonable inquiry,” as is required for certifications under the Title V operating permit program. The commenter suggests that the revised certification could read as follows: “Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, ....” The commenter contends that a “reasonable inquiry” standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

And, in any event, the commenter (2428-API) states that a “technical infeasibility” standard allows for second guessing by regulators or citizen enforcers, which invites a “battle of the experts” in potential enforcement actions. The commenter contends that this diminishes the possibility that the opt outs can be implemented with reasonable certainty.

Rather than creating opt outs that require case-specific certification, the commenter (2428-API) recommends EPA establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. The commenter notes that this is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Commenter (2326-AXPC) requests that BSER exceptions should include economic factors in addition to technical feasibility or safety. The commenter notes that the EPA concedes that it is proposing multiple regulatory requirements whose implementation would be “technically infeasible” for some set of affected facilities. In such cases, the EPA gives affected facilities the ability to “opt out” of the performance standard if the affected facility can show that compliance with the performance standard would be infeasible for technical or safety reasons. As explained below, the commenter believes that “technically infeasible” is a misnomer and EPA should explicitly include economic factors in addition to a technical feasibility analysis.

Within EPA’s NSPS OOOOb/EG OOOOc regulations, the commenter (2326-AXPC) provides that the EPA includes opt out for their regulatory requirements such as the ability to use an emissions control device to handle associated gas,<sup>248</sup> the continued use of pneumatic pumps

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<sup>247</sup> See, e.g., 40 CFR 60.5377b(b)(2).

<sup>248</sup> Proposed 40 CFR 60.5377b(b)(2).

driven by natural gas,<sup>249</sup> and the use of emitting gas well unloading methods.<sup>250</sup> The commenter states that elsewhere in their comments (section II.D.i of their comments) they provide at least one additional recommendation of an opt out with respect to pneumatic controllers. Unfortunately, the commenter expresses that EPA does not provide any information within the rule on how an affected facility is expected to demonstrate that the regulatory provision in question is “technically infeasible” in their case, other than a requirement that a professional engineer or other qualified individual so certify.

Because there is no explanation of technical infeasibility within the rulemaking, the commenter (2326-AXPC) evaluated what EPA has done in other CAA programs. For example, they note that the EPA’s regulations related to best available retrofit technology (BART) determinations under the regional haze program include some insight into how EPA might evaluate technical feasibility considerations.<sup>251</sup> According to EPA’s BART regulations:

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” As explained in more detail below, a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.<sup>252</sup>

The commenter (2326-AXPC) suggests that, while these regulations provide more context than EPA’s proposed NSPS OOOOb/EG OOOOc regulations, the BART regulation conflates economic factors and technical feasibility and does not specifically account for other factors related to potential implementation that may be critical to compliance. The commenter states that the “available” concept is inherently an economic concept as it relates to whether the item is commercially available – i.e., that the price is at such a level that it can be produced commercially. The commenter contends that, if EPA was truly looking at considering technical feasibility without regard to economic viability, whether a technology is commercially available would be irrelevant. And to do so here, would be inappropriate, particularly given the definition of standard of performance. Under CAA section 111(a)(1), standard of performance means

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (taking into account the cost of achieving such reduction and any nonair quality health and

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<sup>249</sup> Proposed 40 CFR 60.5393b(c).

<sup>250</sup> Proposed 40 CFR 60.5376b(c)(2)(ii)(B)(2).

<sup>251</sup> 40 CFR Part 51, Appendix Y.

<sup>252</sup> Appendix Y(D)(1).

environmental impact and energy requirements) the Administrator deems has been adequately demonstrated.<sup>253</sup>

By providing an opt-out, the commenter (2326-AXPC) believes that the EPA inherently recognizes that BSER cannot be met at every facility. Thus, in making the demonstration that use of the opt out is appropriate, the costs of achieving such emissions reduction should be taken into account.

Further, because EPA may only include standards that are determined to be adequately demonstrated, the commenter (2326-AXPC) contends that the technical feasibility for the opt-out provisions in NSPS OOOOb/EG OOOOc, technical feasibility must include considerations such as: ability to access electrical power; landowner access; other local or state regulatory requirements; and other considerations that limit the ability to comply with the standard of performance. In other words, technical feasibility must include considerations beyond just physical impossibility. According to the commenter, anything that would preclude, or hinder implementation of the regulations should be included in a consideration of feasibility – whether technical, economic, or some other appropriate consideration. However, they recommend that EPA be explicit that economics is to be considered in the feasibility analysis – as technical feasibility alone is insufficient.

The commenter (2326-AXPC) provides that they discuss the specific concept that commercially unavailable technologies should not be considered technically feasible in further detail with respect to EPA’s proposed oil well associated gas standards elsewhere in their comments (section II.A.iii of their comment letter).

Instead of EPA conflating technical feasibility and economic considerations, as the commenter (2326-AXPC) suggests that the EPA does in the December 2022 proposal, they recommend that EPA in its final rule transparently state that economic factors must be part of an affected facility’s ability to opt out of the regulatory requirement, in addition to whether installation and operation of the regulatory requirement is technically feasible and safe.

The commenter (2326-AXPC) recommends that EPA adopt the following general standard for opting out of EPA’s performance standards or apply this type of standard in instances where EPA has provided an opt out.

An affected facility may opt out of the standard of performance if any of the following apply:

- The performance standard cannot reasonably be installed and operated at the affected/designated facility including due to technical feasibility, safety concerns, or physical impossibility;
- The cost of compliance with the performance standard would result in the affected/designated facility having a cost-effectiveness greater than \$5,540 per ton of VOCs or \$1,970 per ton of methane or the well is no longer able to economically operate; or

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<sup>253</sup> 42 U.S.C. §7411(a)(1).

- The cost of compliance with the performance standard would be so great that it would result in the affected/designated facility no longer being able to economically operate.

In addition to the general standard provided above, the commenter (2326-AXPC) also request that EPA provide detailed information on what affected facilities can show to meet the requirements for opting out of a control requirement.

In a later comment submission provided by the commenter (3818-AXPC) the commenter expressed serious concerns about the certification requirements for technical infeasibility demonstrations. For example, the commenter notes that the proposal discusses potential for criminal liability related to the technical feasibility demonstration for use of control devices to handle associated gas. The commenter reiterated their position that the CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals, or fails to file or maintain a document filed or required to be maintained under the CAA. The commenter asserts that while they appreciate EPA's recognition that non-emitting approaches are not always practicable and the provision for an alternate path for those situations, we are concerned the potentially punitive nature of these certification requirements will be insurmountable. Not only would the certifier have to prove a negative, that a non-emitting technique is not feasible, they risk personal liability to themselves and their families if their opinion is disagreed with or if a mistake is made, which may not be of their making. It is unlikely that any individual would take such a risk and we argue it is unreasonable and unnecessary to do so.

As a solution, the commenter (3818-AXPC) supported language recommended by API in their comments (copied below).

If EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: "Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on "reasonable inquiry," as is required for certifications under the Title V operating permit program. The revised certification could read as follows: "Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, ...." A "reasonable inquiry" standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

Response II-6-112: The EPA agrees with the commenter that adding "reasonable inquiry" to the statement of certification may alleviate the concern that the effort to explore alternatives to BSER could be unfairly questioned by permit reviewers.

The EPA received data and comments supporting the determination that BSER is routing to a sales line, so long as an operator may with reasonable effort choose a better alternative for their specific physical or operating environment. The analysis that EPA performed to determine the

cost of implementing BSER makes clear that associated gas is a marketable product when the determinants for routing to a sales line are favorable, when the well is new and plans to extract and market the product can be customized as it comes on-line. We believe the commenter's concern is focused on existing production where the location and logistical concerns limit the options available. The EPA accommodated those concerns by allowing reconstructed wells to flare where alternatives are infeasible. The EPA considered that the physical space to operate a non-flaring alternative may be unavailable or that the logistics of routing to sales may be insurmountable even with reasonable time and effort. Other commenters suggested that injecting the associated gas into the well or other well would not always be viable. The EPA points out that based on the 2021 proposal, we are already relying on delegated authorities to make determinations on site-specific facts within their jurisdictions to determine the credibility of a reasonable effort to use non-flaring alternatives to use or dispose of associated gas.

The EPA also subcategorized wells with low levels of associated gas to allow them to flare without making a showing that other alternatives are infeasible. This completely addresses the concerns of operators with exceedingly small amount of gas to dispose. This subcategory should also alleviate some concern regarding the effort required of delegated authorities to make these determinations.



## Chapter 7. Process Controllers

### 7.1 NSPS OOOO and EG OOOOc Affected Facility Definition

#### *7.1.1 Support for EPA Proposed Affected Facility Definition*

Comment: Several commenters (1581-Kathairos Solutions US, Inc. (Kathairos), 2410- California Office of the Attorney General (CA AG) et al, 2433- Environmental Defense Fund (EDF) et al, 2wed446- Independent Petroleum Association of America (IPAA)) provide support for EPA's December 2022 proposed pneumatic controller affected facility definition. Some of the specific comments provided are included in the following paragraphs.

Commenter (2410-CA AG et al) supports EPA's proposed definition of pneumatic controller affected facilities to include the collection of natural gas-driven pneumatic controllers at a site instead of each individual natural gas-driven controller. The commenter further supports EPA's proposal to include: (1) controllers where the emissions are collected and routed to gas-gathering flow line or collection system to a sales line or used as an onsite fuel source and (2) self-contained natural gas pneumatic controllers.

Commenter (2446-IPAA) supports EPA's proposed definition of affected facility opposed to defining each individual natural gas-driven pneumatic device as an affected facility.

Commenter (2433-EDF et al) states that EPA properly defines the affected facility as all controllers at a site for new, modified, and reconstructed facilities, including "modification" and "reconstruction", site-wide pneumatic controller affected facility definition, the two-year window, the inclusion of routed and self-contained controllers, and intermittent controllers.

The commenter (2433-EDF et al) supports EPA's application of "modification" and "reconstruction" in this context, and its conclusion that a modification or reconstruction would result in all controllers at a site becoming a new pneumatic controller affected facility subject to new source performance standards (NSPS) OOOOb. The commenter adds that they believe EPA has reasonably defined an "affected facility" as the collection of controllers at a site. And in applying this definition, EPA's clarification that all controllers at a facility become subject to NSPS OOOOb after the addition of one or more pneumatic controllers is accurate, since doing so would be a physical change resulting in increased emissions. They contend that this is the definition of "modification" under the Act and would necessitate the conversion of all controllers at the site to zero-emission technologies.

According to the commenter (2433-EDF et al), EPA's interpretation of the 2-year 50 percent threshold for the definition of "reconstruction" aligns with the Clean Air Act's (CAA's) "reconstruction" definition, which means the replacement of components of an existing facility to such an extent that "the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." In accordance with this definition, it is reasonable for EPA to equate replacing 50 percent of controllers at a site with 50 percent of the fixed capital costs required to construct an entirely new facility. If the affected facility is all controllers at a site, which, as explained previously, is

appropriate, then 50 percent of the cost to construct an entirely new “facility” would amount to replacing 50 percent of controllers at the site. Since individual controllers are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of controllers being replaced at a site and the percentage of the fixed capital cost that would be required to construct an entirely new comparable facility. Without a two-year window, operators could create multiple replacement programs below the 50 percent threshold over the course of several years (e.g., 20 percent in October 2026, and 30 percent in September 2028) to avoid compliance with NSPS OOOOb. The commenter notes that allowing this loophole would undermine Congress’ intent that air quality be enhanced over the long term with the turnover of polluting equipment, and with the intent of the EPA’s reconstruction provisions. They add that the two-year period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic controllers is proposing an extensive controller replacement that the exact type of program 40 CFR 60.1 was intended to regulate. The two-year time frame also recognizes that it is more cost effective to replace larger chunks of controllers rather than initiate several, smaller replacement programs.

Response II-7-1: These comments are supportive comments on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2433-EDF et al) supports EPA’s decision to include intermittent vent controllers in its proposed standards. The commenter notes that the Carbon Limits 2021 tool shows that converting to zero-bleed remains cost-effective even for sites with just one intermittent controller, especially when considering multi-pollutant costs. The commenter also supports EPA’s response to industry comments that emissions reductions from intermittent vent controllers are already captured in EPA’s cost analysis for the proposed leak detection and repair (LDAR) requirements. As EPA notes, the average emission factor that the EPA uses considers low-emitting properly operating controllers, as well as those that are not operating properly and that are venting during idle, and EPA finds that factor is the correct factor to represent the “uncontrolled” emissions from the universe of intermittent vent controllers. Additionally, these devices are not accounted for in EPA’s modeling of the LDAR provisions.

The commenter (2433-EDF et al) adds that inclusion of intermittent controllers is essential because EPA estimates that over 1.5 million metric tons of methane – 71 percent of emissions from pneumatic controllers - are from intermittent vent controllers. The commenter also supports EPA’s conclusion that using one intermittent controller should not exempt an operator from the standard. The commenter notes that the EPA’s own cost analysis demonstrates the cost-effectiveness of the standard with one controller on-site. The commenter also notes that the Carbon Limits 2021 tool shows that converting to zero-bleed remains cost-effective even for sites with just one intermittent controller, especially when considering multi-pollutant costs.

Response II-7-2: These comments are supportive comments on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

### 7.1.2 Request for Related Definitions/Other Clarifications

Comment: Commenter (2399- GPA Midstream Association (GPA)) proposes the following changes to the definitions of certain terms (underlined text indicates new text and struck-out text indicates deleted text):

- *Intermittent vent natural gas-driven pneumatic controller* means a process control device that uses natural gas and ~~natural gas-driven pneumatic controller~~ that is not designed to not have a continuous bleed rate but is instead designed and operated to only release natural gas to the atmosphere as part of the actuation cycle.
- *Non-natural gas-driven pneumatic controller* means ~~an automated~~ process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position.
- *Pneumatic controller* means ~~an automated instrument~~ process control device used for maintaining a process condition such as liquid level, pressure, delta-pressure, or temperature by changing valve position.
- *Self-contained pneumatic controller* means a natural gas-driven pneumatic controller ~~in which the motive gas is not vented to the atmosphere but captured in a closed vent system for process use or control such that there are no direct methane or VOC emissions from the controller~~ that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

Commenter (2428 - American Petroleum Institute (API)) proposes the following changes to the definitions of certain terms (underlined text indicates new text and struck out text indicates deleted text):

- *Bleed rate* means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.
- *Continuous bleed* means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply natural gas from to a fixed orifice pneumatic controller.~~
- *Non-natural gas-driven pneumatic controller* means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~
- *Pneumatic controller* means an automated instrument that manipulates a valve's position with pressurized gas to used for ~~maintaining~~ a process condition such as liquid level, pressure, delta pressure and temperature.
- *Self-contained pneumatic controller* means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas into the downstream piping for process use, sales, or control such that there are no direct methane or VOC emissions from the controller.~~ , resulting in zero methane and VOC emissions

Response II-7-3: The EPA considered the recommended changes but determined that the original language was clear and that the recommended changes are not necessary to convey the meaning of the terms. Therefore, the EPA has not made the suggested changes to these definitions in the final rule.

Comment: Commenter (2403- The Petroleum Alliance of Oklahoma (PAO)) requests EPA include a provision that allows operators to replace high-bleed controllers with low-bleed controllers without becoming an affected facility.

Commenter (2399-GPA) supports the proposed definition of “affected facility” for natural gas driven pneumatic controllers that allows for replacements without triggering the modification requirements. The commenter states that an “in-kind” replacement of a natural gas driven pneumatic controller would not be a modification “provided that less than 50 percent of the controllers are replaced at the same time.” The commenter notes that this is a reasonable approach, as if EPA did not allow this, operators would be discouraged from voluntarily replacing high-bleed natural gas-driven controllers with low-bleed controllers.

Response II-7-4: The EPA disagrees with the commenters that sites should be allowed to replace high-bleed controllers with low-bleed controllers without becoming an affected facility. First, we note that the final EG requires that existing sites outside of Alaska and those in Alaska with access to electrical power replace both high-bleed and low-bleed controllers with zero-emitting controllers or route the controller emissions to a process, such that there are zero emissions of methane and VOC. As both the EG for existing sources and the NSPS for new sources require zero emissions from controllers at most sites (i.e., sites outside of Alaska and those in Alaska with access to electrical power), all of these sites will essentially have process controller affected facilities that require zero-emissions. For sites in Alaska without access to electrical power, the NSPS will only apply if more than half of the controllers are replaced in a 24-month period, thereby meeting the definition of reconstruction.

Comment: Commenter (2326- American Exploration & Production Council (AXPC)) states that the EPA proposes best system of emission reduction (BSER) that would result in no volatile organic compound (VOC) or methane emissions from pneumatic controllers, pneumatic pumps, or gas well liquids operations. Thus, compliance with EPA’s proposed BSER ensures that pneumatic controllers, pneumatic pumps, and gas well liquids operations are not “stationary sources” because compliance will not, and could not, result in emissions. According to the commenter, this exceeds EPA’s authority granted under CAA §111. The commenter requests that EPA define the NSPS OOOOb pneumatic controller and pneumatic pump affected facilities as equipment designed to emit VOC and/or methane and similarly define the emission guidelines (EG) OOOOc designated facility to include equipment designed to emit methane. Failing to define the affected/designated facility in this manner would result in the inappropriate imposition of onerous recordkeeping and reporting requirements on equipment that is not a stationary source.

Response II-7-5: It appears the commenter mistakenly believed the EPA included all process controllers in the affected facility definition. The December 2022 Supplemental Proposal only included process controllers driven by natural gas in the affected facility definition in §60.5365b(d); however, it did require that records be kept of the process controllers that were not driven by natural gas and not included in the affected facility definition. The process controller affected facility was defined as follows in the December 2022 Supplemental Proposal:

Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided the records in §60.5420b(c)(6)(i)(A) or (B) are maintained, as applicable.

The EPA agrees that process controllers with no potential to emit methane or VOC to the atmosphere should not be included in the affected facility and is finalizing this aspect of the affected facility definition. After considering these comments regarding the recordkeeping and reporting requirements for process controllers with zero emissions, we have determined that it is appropriate in this instance to require identification of the equipment that is included in the affected facility, rather than the equipment that is not part of the affected facility. The process controllers included in the affected facility are those that are subject to the emissions standards in the rule, whereas process controllers not included in the affected facility are not subject to the emissions standards in the rule, and also have no potential to emit methane or VOCs. Therefore, we have revised the recordkeeping and reporting requirements to require identification only of process controllers that meet the finalized definition of an affected facility, which are those process controllers that are driven by natural gas and are not emergency shutdown devices.

### ***7.1.3 Modification/Reconstruction***

Comment: Commenter (2399-GPA) supports the December 2022 proposal's definitions of "modification" and "reconstruction."

Commenter (2254- Permian Basin Petroleum Association (PBPA)) states EPA should clarify in the rule text that, for purposes of the collection of controllers or pumps at a site, a modification occurs only when a natural gas-driven pneumatic controller is added.

Response II-7-6: The EPA notes that the definitions of modification and reconstruction have been revised in the final rule to further clarify that the occurrence of a modification or reconstruction is based on natural gas-driven process controllers. These changes clarify but do not change the intent of the definitions included in the December 2022 Supplemental Proposal.

Comment: Commenter (2446-IPAA) requests that the EPA replace references to "site" in the relevant definitions of modification and reconstruction with "pneumatic controller affected facility." The commenter suggests that a similar clarification be considered for all sections of the rule, so that it is made completely clear that the owner or operator is responsible only for the collectives of equipment that it owns at a site, even though a "site" might comprise equipment that is under separate ownership and control. This includes but is not limited to (1) the "affected facility" for fugitive emission control purposes, which, like "pneumatic controllers," is defined by reference to the totality of equipment at a site, and (2) the super emitter response program, which purports to impose obligations on a site, when it needs to be clear that the obligations are imposed on the owner or operator of the individual equipment item that is responsible for any alleged super-emitting event.

Commenter (2446-IPAA) states if EPA proceeds to describe the collective of all controllers at a site as the "affected facility," it must revise its proposed regulatory text to make clear that regulated entities will not be responsible for equipment that they neither own nor operate at shared production sites.

The commenter (2446-IPAA) explains that, as proposed, "modification" and "reconstruction" of a pneumatic controller affected facility can be triggered by installation of new pneumatic controllers at a "site." The term "site" is undefined and creates uncertainty where, as is common, multiple companies operate in close proximity. The commenter notes that owners and operators cannot be responsible for equipment over which they have no control. The commenter recommends that the EPA revise the definition of "pneumatic controller affected facility" to read:

Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers that you own or operate at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station.

Response II-7-7: To clarify that the modification and reconstruction provisions are related to the affected facility, we have revised the modification and reconstruction provisions in the final rule for process controllers and pumps to specify that the provisions apply to the affected facility rather than the site. These revisions should clear up any potential confusion that a change made to the site, such as the addition of a process controller, that is owned or operated by another entity could affect the status of an affected facility owned or operated by another entity.

Comment: Commenter (2483-INGAA) states there are likely instances in which a natural gas-driven pneumatic controller has been installed between November 15, 2021, and December 6, 2022, with operators unaware of the implications related to NSPS OOOOb due to the changes that occurred between the November 2021 and December 2022 proposal. The commenter asserts that this drastic change in the definition of a pneumatic controller affected facility that occurred between the November 2021 and the December 2022 proposals require that EPA change the applicability date of NSPS OOOOb for pneumatic controllers to the date of the actual proposal of the regulatory language – i.e., December 6, 2022 – even if EPA continues to maintain that the rest of NSPS OOOOb should have an applicability date of November 15, 2021. If EPA does not change the applicability date of the NSPS OOOOb standards for pneumatic controllers, the commenter requests that EPA seek to mitigate the retroactive effect of the proposed rule by giving operators the option to convert the natural gas-driven pneumatic controller installed before December 6, 2022, to zero-emissions within 60 days after NSPS OOOOb becomes final and avoid having triggered a modification of the entire affected facility without full knowledge of the implications for modifying the group of controllers. The commenter proposes the following reg text for section 40 CFR 60.5365b(d)(1)(i):

Natural gas-driven pneumatic controllers installed between November 15, 2021, and December 6, 2022, that comply with the zero-emissions requirements in §60.5390b(a) by [INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER] shall not constitute a modification of the affected facility.

Response II-7-8: The applicability date for process controllers under NSPS OOOOb is the date of publication of the December 2022 supplemental proposal, December 6, 2022.

Owners/operators have 60 days after publication of the final rule in the Federal Register to comply with the requirements of the NSPS.

Comment: Commenter (2258- Marcellus Shale Coalition (MSC)) notes that 40 CFR 60.5365b(d)(1) states that facilities shall become subject to 40 CFR 60.5390b upon an increase in a facility pneumatic controller count of one or more. The commenter requests a revision to the definition in 40 CFR 60.14 or specific additional language in 40 CFR 60.5365b(d)(1) as follows:

a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more, unless the new controller(s) result in a reduction of emissions.

The commenter (2258-MSC) also suggests that language be included in this section similar to the process unit equipment affected facility stating that addition (or replacement) of natural gas-driven pneumatic controllers for the purpose of process improvement which is accomplished without a capital expenditure shall not be considered a modification.

Commenter (2483- Interstate Natural Gas Association of America (INGAA)) indicates that, as proposed, the regulations would consider the installation of a zero-emitting gas-driven pneumatic controller as triggering a modification (where there would not be a corresponding emissions increase). To rectify this issue, the commenter suggests that the definition of pneumatic controller affected facility in 40 CFR 60.5365b(d) be modified as follows (underlined text indicates new text):<sup>1</sup>

*40 CFR 60.5365b(d)-*

(d) Each pneumatic controller affected facility, which is the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven pneumatic controllers that function as emergency shutdown devices or have zero-emissions in accordance with §60.5390b(a), and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records in §60.5420b(c)(6)(i)(A) or (B) are maintained, as applicable.

Commenters (2283- Endeavor Energy Resources, L.P. (Endeavor Energy), 2305- Williams Companies, Inc. (Williams), 2446-IPAA, 2483-INGAA) states that an emissions increase must occur to be considered a “modification” and that the proposed definition of “modification” conflicts with the statutory definition of “modification” in Section 111 of the CAA and with the

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<sup>1</sup> The proposed regulatory text for the definition of pneumatic controlled designated facility in 40 CFR 60.5386c(d) should similarly be revised as follows: “(d) Each pneumatic controller designated facility, which is the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Natural gas-driven pneumatic controllers that function as emergency shutdown devices or have zero-emissions in accordance with §60.5394c(a), and pneumatic controllers that are not driven by natural gas are exempt from the designated facility, provided that the records in §60.5420c(c)(5)(i)(A) or (B) are maintained, as applicable.”

Agency's own definition of "modification" in 40 CFR 60.14. In both of these definitions, an emissions increase must occur for a physical or operational change to be considered a "modification". According to the commenter, as proposed, 40 CFR 60.5365b(d)(1) focuses only on an increase in the number or count of pneumatic controllers at an affected facility irrespective of whether there is an accompanying emissions increase. They note that such a definition would result in a facility being "modified" even if it adds a non-natural gas pneumatic controller to an affected facility. Having now undergone a "modification", the commenter explains that an owner or operator must now transition all of its pneumatic controllers to zero-emitting devices. The commenters contend that this is an unreasonable and impermissible result under the CAA and conflicts with EPA's own regulations.

Commenter (2403-PAO) states if an operator can provide information that emissions have not increased with the addition of one or more controllers at the site, then EPA should not consider this a modification. The commenter requests EPA include a provision in the rule that allows operators to provide information showing that if emissions have not increased by the addition of a pneumatic controller, then it does not constitute a modification that makes the entire collection of pneumatic controllers at the site a pneumatic controller affected facility.

Commenter (2283-Endeavor Energy) states EPA's current proposal regarding pneumatic controllers and pumps ignores the practical realities of upstream oil and gas operations and unjustifiably deviates from past practice in defining a "modification" that would trigger the NSPS requirements. To create a durable and workable rule for both new and existing sources, the commenter requests that the EPA reconsider and revise the provisions to better comport with the existing CAA regime and better reflect the true costs of its proposed provisions.

Comment: Commenter (2428-API) states that throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. The commenter recommends that the EPA be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, they note that an existing well site that is already connected to grid power should not trigger a modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions. The commenter offers the following suggested regulation changes (underlined text indicates new text and struck out text indicates deleted text):

*40 CFR 60.5365b(d)(1)-*

(1) For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.

Response II-7-9: To clarify that a modification is triggered only if there is the potential for an emissions increase from the addition of a process controller, we have revised the modification provisions of §60.5390b(d)(1) to specify that a modification occurs when the number of natural gas-driven process controllers is increased by one or more.



The EPA disagrees that natural gas-driven process controllers added to the site for the purpose of process improvement without capital expense should not be considered a modification and that the process controllers and pumps requirements for modifications do not comport with the existing CAA regime for modifications. Modifications are determined based on an increase in emissions from a change in the facility processes or equipment, rather than capital costs. For process controllers, there are many zero-emissions controller options available to owners/operators if a change in process is necessary, which requires a change in the process controller. Therefore, there is no reason to allow an increase in emissions without considering it a modification, and the EPA has not revised the rule to accommodate those situations.

Comment: Commenter (2428-API) states it is unclear how the notifications from 40 CFR 60.15 apply to the reconstruction provision proposed in 40 CFR 60.5365b(d)(2). The proposed language in 40 CFR 60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in 40 CFR 60.15, which include 60-day notification and Administrator approval. The commenter states that this directly conflicts with information presented in Table 5 that states 40 CFR 60.15(d) does not apply to pneumatic controllers. The commenter believes it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

Commenter (2305-Williams) states if one owner or operator makes changes to its portion of the facility so that it triggers a "modification", these actions should not affect the rest of the facility that is under control of a separate owner or operator. And the commenter proposes the following changes (struck out language indicates deleted text):

...a modification occurs when an owner or operator increases the number of natural gas-driven pneumatic controllers at the pneumatic controller affected facility that it owns or operates ~~at a site is increased~~ by one or more which results in a net emissions increase from the affected facility.

Response II-7-10: We agree that we did not intend for facilities to be required to notify the Administrator of upcoming process controller replacements that would constitute a reconstruction or for the Administrator to be required to review the notification and determine whether the replacements constitute a reconstruction. We have revised the final regulatory text to not refer to the requirements of 40 CFR 60.15(d) and have kept the information presented in Table 5 of the proposed regulatory text, which states that 40 CFR 60.15(d) does not apply to process controllers.

Comment: Commenter (2326-AXPC) states that the number of pneumatic controllers that trigger a modification must warrant the additional capital expenditure at the facility of retrofitting the entire facility to be non-emitting. The commenter suggests that the EPA increase the number of pneumatic controllers that require a modification to a meaningful number that would justify the implementation of retrofits at an existing facility. In most cases, according to the commenter, one pneumatic controller addition would not warrant such additional capital expenditure.

Response II-7-11: The EPA is not redefining what constitutes a modification under 40 CFR part 60 in §60.5390b(d)(1). The definition of modification in §60.2 states that any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant emitted into the atmosphere by that facility is a modification. The language of §60.5390b(d)(1) only clarifies that the addition of one natural gas-driven process controller to an affected facility would be considered a modification because such an addition has the potential to increase emissions of methane and VOC to the atmosphere. As any increase in emissions triggers the modification status, and the addition of one natural gas-driven process controller meets this threshold, the EPA has not revised this modification provision in the final rule.

Comment: Commenter (2337- Kansas Department of Health and Environment (KDHE)) notes that heretofore, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps has not been considered a fugitive emission if the device is operating properly and in accordance with manufacturer's specifications. The commenter recommends that in light of the very heavy financial burden this proposed rule places on oil and gas owners and operators, EPA provide a moratorium on implementing modification requirements for at least five years.

Response II-7-12: The EPA has determined that the costs of using zero-emitting process controller technologies for new sources and changing to zero-emitting technologies for existing sources is reasonable, considering the emissions reductions that will be achieved. This same principal applies to affected sources undergoing a modification. Therefore, the EPA has not revised the modification requirements to provide a moratorium on implementation of the process controller requirements for any period of time.

Comment: Commenter (2428- API) offered a suggested regulatory language for reconstruction, primarily to clarify that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers as shown below:

*40 CFR 60.5365b(d)(2)-*

(2) For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of controllers” criterion in (d)(2)(ii), they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference “fixed capital cost” through an initial showing that the number of controllers replaced exceeds

50 percent. For purposes of paragraphs (d)(2)(i) and (ii), “commenced” means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.

If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The “fixed capital cost of the new pneumatic controllers” includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in §60.15(d), and the provisions of §60.15(e) and (f) related to the Administrator’s review.

Commenter (2428-API) asserts that reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller. Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short-term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, they state that this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

Response II-7-13: To clarify that reconstruction is triggered only when natural gas-driven process controllers are replaced, we have revised the reconstruction provisions of §60.5390b(d)(e) to specify that a modification occurs when the number of natural gas-driven process controllers in the affected facility replaced is 50% or more. As the EGs require for most

sites (i.e., those outside of Alaska and those in Alaska with access to electrical power) that process controllers have zero emissions, these existing sites will be required to replace all high-bleed process controllers on the schedule set out by the EG or the NSPS, if there is a modification or reconstruction of the affected facility. Therefore, the EPA believes any disincentive to act quickly to change out the remaining high-bleed process controllers is outweighed by the impending requirements to do so.

Comment: Commenter (2446-IPAA) notes that the EPA solicits comment on their proposed two-year rolling aggregation period for all continuous programs of pneumatic controller and pneumatic pump replacements. The commenter provides that they support the concept of a fixed two-year aggregation period, but NOT a rolling two-year period. The commenter believes that the administrative burden of keeping-up with a rolling two-year period outweighs the benefits of the approach.

Response II-7-14: The EPA is clarifying in the final rule that the rolling two-year period means a 24-month look-back period. For example, if an owner/operator wishes to replace 10 of 24 natural gas-driven process controllers in April of 2024, the period of time that would need to be considered is the past 24 months, or to April of 2022. If the owner/operator wishes to replace an additional 6 of 24 natural gas-driven process controllers in August of 2025, the period of time that would need to be considered is again the past 24 months, or to August of 2023. In April of 2024, 10 of 24 controllers would be replaced, which would not be considered to be a reconstruction since 10 is less than 50% of 24 controllers will have been replaced. However, in August 2025, if an additional 6 controllers will be replaced, considering the 10 controllers replaced in 2024, 16 of 24 controllers will have been replaced in a 24-month period, and this would be considered to be a reconstruction. As the recordkeeping requirements of the NSPS require records to be kept for 5 years, the EPA has determined that owners/operators will have records available regarding equipment changes over the past 24 months. Therefore, the 24-month look-back period is being promulgated in the final NSPS.

Comment: Commenter (2483-INGAA) states the definition of reconstruction for a pneumatic controller affected facility in proposed 40 CFR 60.5365b(d)(2) does not clearly specify that only the capital costs of natural gas-driven pneumatic controllers being added as replacements are considered when determining if reconstruction of the affected facility has occurred. Similarly, they note that when applying the “number of controllers” criterion in 40 CFR 60.6365b(d)(2)(ii), only the addition of natural gas-driven pneumatic controllers as replacements should be considered. The commenter states that the regulatory text should not provide a disincentive for replacing a majority of pneumatic controllers at a site with zero-emissions pneumatic controllers. If all pneumatic controllers are considered in the reconstruction analysis, then replacing a majority of pneumatic controllers at a facility with zero-emissions controllers would subject the balance of the pneumatic controllers to the zero-emissions requirements under the reconstruction provisions. The commenter provides the following suggested regulation changes (underlined text indicates new text and struck out text indicates deleted text):

(2) For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of pneumatic controllers is replaced. That is, if an owner or operator meets the definition of reconstruction through the “number of controllers” criterion in (d)(2)(ii), they will have shown that the “fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,” as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference “fixed capital cost” through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), “commenced” means that an owner or operator has undertaken a continuous program of pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of pneumatic controller replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic controllers at the site. The “fixed capital cost of the new natural gas-driven pneumatic controllers” includes the fixed capital cost of all pneumatic controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the pneumatic controllers at a site are replaced with natural gas-driven pneumatic controllers. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator’s review.

Response II-7-15: The EPA intends for owners/operators to replace all process controllers with zero-emissions controllers when 50% or more of the controllers are replaced at the site with zero-emissions controllers. As commenters on the November 2021 proposal pointed out, converting a single pneumatic controller to a zero-emitting device typically requires a conversion of all controllers at the facility to zero-emitting devices.<sup>2</sup>

#### ***7.1.4 Affected Facility - Collection of Controllers***

Comment: Commenter (2202-TXOGA) states newly expanded definitions of what constitutes an “affected facility” for pneumatic controllers and pumps increases the scope of EPA’s control over the regulated community, while providing little meaningful emissions reduction. They add that it is also unclear why the definition of “affected facility” for pneumatic controllers has changed from one controller to the collection of all controllers at a site, while just one controller’s presence at a site would make it a “centralized production facility.”

Response II-7-16: As explained in the December 2022 Supplemental Proposal (87 FR 74756) The EPA proposed the change in the affected facility definition based on the consistent recommendation of numerous commenters, particularly commenters from the oil and natural gas industry. Several comments on the November 2021 proposal noted the disconnect between the pneumatic controller affected facility definition (i.e., an individual controller) and the cost analysis, which was based on the replacement of all pneumatic controllers with zero-emitting devices at a site. One commenter pointed out the complexities of tracking and managing the universe of pneumatic controllers at a site when some are affected facilities and others are not and recommended that the EPA propose a simpler and more robust system. Another commenter indicated that defining the affected facility on a site-wide basis aligns with how emissions from pneumatic controllers will likely be handled by owners and operators of oil and natural gas facilities. Another commenter discussed the fact that converting a single pneumatic controller to a zero-emitting device typically requires a conversion of all controllers at the facility to zero-emitting devices.

For the purpose of the fugitive emission standards, the EPA defines a “centralized production facility” based on the presence of major production and processing equipment, and the types of equipment that are major production and processing equipment are listed. The EPA considers natural gas-driven process controllers to be one of several components that are major production and processing equipment. For the sake of clarity in this definition, the EPA specifies the equipment itself rather than using the “affected facility” terminology, but the effect is the same. If a site has only one natural gas-driven process controller, this controller would comprise the entire process controller affected facility. The presence of this affected facility, which is major production and processing equipment, would make the site a “centralized production facility.”

#### ***7.1.5 Affected Facility-Natural Gas-Driven Controllers – Emissions Routed to a Process/Self-Contained Natural-Gas Driven Pneumatic Controllers***

Comment: Commenter (2202-TXOGA) notes that they do not support EPA’s change to the affected facility definition in the December 2022 Supplemental Notice to not exclude natural

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<sup>2</sup> See Document ID Nos. EPA-HQ-OAR-2021-0317-0808.

gas-driven controllers from which all emissions are collected and routed to a process, as well as self-contained natural gas-driven pneumatic controllers. While such natural gas-driven controllers were excluded from the November 2021 Notice, it is now proposed “to include these types of natural gas-driven controllers because they are driven by natural gas.” The commenter notes that the December 2022 proposal does not explain why additional regulation of such equipment—which assists in the overall improvement of air quality around natural gas facilities—should be required. The commenter states that treating zero-emitting pneumatic controllers and pneumatic pumps as affected facilities will have very little effect on reducing emissions. They added that zero-emitting pneumatics are an example of industry innovation to solve the problem of methane leaks.

Commenters (2227-WEA, 2403-PAO) state that, by treating them as affected facilities, EPA disincentivizes operators to take positive steps to eliminate emissions, and it potentially disincentivizes new technology development. If there were to be a malfunction of a zero-emission pneumatic controller or the gas capture system connected to a pump, the malfunction would be found and subsequently repaired through LDAR. The commenters assert that there is no need to include zero-emissions equipment as affected facilities.

Commenters (2326-AXPC, 2428-API) state that if self-contained natural gas-driven controllers are maintained as affected facilities, given the simplicity and low potential for leaks or defects along the piping, EPA could and should allow increased flexibility in implementation of periodic monitoring along this piece of pipe by incorporating these into the fugitive emission monitoring requirements under 40 CFR 60.5397b instead of adding the provisions that are more relevant for covers and closed vent systems as they pertain to storage vessels in 40 CFR 60.5416b(b). Additionally, they suggest that the EPA also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program when applicable.

Commenter (2399-GPA) states any controllers that are not driven by natural gas (and are, thus, zero emission) should be excluded from the class of applicable facilities. According to the commenter, imposing requirements on sources that do not emit pollutants is unnecessary and beyond EPA’s CAA authority.

Response II-7-17: The EPA has determined that process controllers not driven by natural gas should not be part of the affected facility definition, as by virtue of their operation, they have no potential for emissions of methane or VOC. For process controllers that are driven by natural gas but that have emissions routed to a sales line or a process, there is still the potential for leaks and malfunctions that would result in methane and VOC emissions. There are also requirements for these process controllers to ensure the closed vent systems used to route emissions are functioning without emissions, and there are associated monitoring, recordkeeping, and reporting requirements. Therefore, the EPA is including these process controllers in the affected facility definition.

## 7.1.6 Exemptions

### 7.1.6.1 Temporary Equipment

Comment: Commenter (2433-EDF et al) urges EPA to reject the option of exemption. Temporary equipment moves around and degrades quickly, making it prone to leakage and malfunctions leading to excess venting. As a result, standards for temporary equipment should be at least as stringent as those for permanent installations. One industry commenter noted that an exemption is needed because temporary equipment is often remote, in which case it might be hard to connect to the grid or an onsite control device. Solar panels is a perfectly feasible and cost-effective option.

The commenter (2433-EDF et al) suggests that, if EPA includes an exemption for temporary equipment, it should be at least as protective as the exemption for temporary equipment in Colorado, or more so. That state's Air Quality Control Commission (AQCC) Regulation 7, Part D, Section III.C.4.e<sup>3</sup> allows operators to use controllers that emit natural gas located on temporary or portable equipment that is used (1) for well abandonment activities,<sup>4</sup> (2) prior to or through the end of flowback,<sup>5</sup> (3) for up to 60 days upon notice to the Air Pollution Control Division (APCD)<sup>6</sup>, and (4) for longer than 60 days if the operator submits justification to the Division for continued use at least 14 days before the 60-day period expires.<sup>7</sup> Under this regulation, operators are not permitted to use temporary equipment to increase production or on equipment which would increase the throughput capacity of a facility, as operators should be required to design operations for an increase in production from the start. For use beyond 60 days, the operator may seek an extension from the Division by submitting justification at least 14 days prior to the end of the 60-day period based on certain information.

The commenter (2433-EDF et al) continues to explain that the Colorado regulations also require owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas to conduct audio, visual and olfactory (AVO) and Approved Instrument Monitoring Method (AIMM) inspections of those controllers on the same schedule as the associated well production facility or compressor station,<sup>8</sup> and to comply with repair, recordkeeping, and reporting requirements.<sup>9</sup>

If EPA decides to include an exemption for temporary equipment (and it should not), the commenter (2433-EDF et al) suggests that it require a similar approach. The commenter states that the EPA should limit any temporary equipment exemption to the activities outlined above, and otherwise enforce a time limit of 30 days. The agency should also require that operators seeking to extend the exemption file a request no later than two weeks before the 30-day limit expires. The request should include the type of equipment being used, the time needed, and the

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<sup>3</sup> 5 Colo. Code Regs. § 1001-9-D-III.C.4.e. (2023).

<sup>4</sup> Id. § 1001-9-D-III.C.4.e.(i)(B).

<sup>5</sup> Id. § 1001-9-D-III.C.1.e.(iv)(B).

<sup>6</sup> Id. § 1001-9-D-III.C.4.e.(i)(C).

<sup>7</sup> Id.

<sup>8</sup> Id. § 1001-9-D-III.C.4.e.(i)(C)(2)(a).

<sup>9</sup> Id. § 1001-9-D-II.E.



reasons for the extension request. Finally, the commenter asserts that the EPA be required to review and either approve or reject the extension request before the 30-day limit expires.

Commenters (2383-BH, 2428-API) state retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, technically achievable, or practically attainable. Commenter (2383-BH) states that an exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado. The commenter recommends that pneumatic controllers located on temporary or portable equipment be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. The commenter suggests exemptions for:

- Natural gas-driven pneumatic controllers on temporary use equipment that is skid mounted or permanently attached to a platform that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days,
- Pneumatic controllers associated with drilling and completion equipment.

Commenters (2326-AXPC, 2403-PAO) request that temporary pneumatic controllers be exempt from the proposed requirements. Commenter (2326-AXPC) requests that the EPA clarify that the addition of a temporary pneumatic controller at a site is not a modification of the pneumatic controller affected facility under NSPS OOOOb if the temporary pneumatic controller remains onsite for less than 180 days. The commenter further requests that EPA exempt temporary pneumatic controllers.

Commenter (2326-AXPC) explains that requiring the costly retrofit of an air supply system to accommodate a temporary operating condition is not cost-effective or practical. Second, to route a temporary pneumatic controller to a process would require significant lead time, an engineering analysis, and a facility shutdown. The commenter asserts that this would not be cost-effective for a temporary operating condition. The commenter adds that there is precedent for EPA providing exemptions for other temporary oil and gas equipment, and doing so for pneumatic controllers would be consistent with this precedent. For example, EPA exempts temporary skid-mounted or mobile storage vessels from NSPS OOOOa<sup>10</sup> and provides a similar exemption in NSPS OOOOb and EG OOOOc.

Response II-7-18: In the December 2022 Supplemental Proposal, the EPA requested information related to process controllers on temporary equipment, including specific examples of when temporary equipment is used, the function of the controllers during this time, how they are powered, and the typical duration of their usage. The EPA also requested information explaining in detail why the zero-emission solutions that are used for the permanent equipment at the site cannot be also used for this temporary equipment. Commenters did not provide this type of information, and the EPA does not have other information to justify the use of non-zero-emissions solutions for temporary equipment. Therefore, the final rule has not been revised from

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<sup>10</sup> 40 CFR 60.5430a (“storage vessel” definition).

the proposal to include an exemption from the process controller standards for temporary equipment.

#### 7.1.6.2 Exemptions Based on Remaining Service Life

Comment: Commenter (2326-AXPC) states EPA does not appropriately consider remaining service life in establishing the non-emitting requirements for existing pneumatic controllers. Based on the normal decline of a well, at some point, natural gas production may decrease below a threshold for which the operator could continue to use natural gas-driven pneumatic controllers. The commenter notes that requiring the expense of replacing or retrofitting pneumatic controllers at a facility that will not use them for a substantial amount of time is not cost-effective. The commenter recommends that the EPA allow exemptions when the remaining service life at the time of the effective date for the requirement is less than 3 years.

Response II-7-19: The EPA notes that the implementing regulations for emission guidelines under CAA 111(d) contained in 40 CFR part 60, subpart Ba include provisions with a process for states to apply a less stringent standard taking into consideration factors such as the remaining useful life of such source. These provisions address applying a less stringent standard due to an unreasonable cost of control resulting from plant age, location, or basic process design. As this provision already exists, and is applicable to development of state plans under EG OOOOc, the EPA has determined that revision to the oil and natural gas emissions guidelines to address the commenter's concerns is not necessary.

#### 7.1.6.3 Emergency Shutdown Devices and Failsafe Safety Applications

Comment: Commenter (2399-GPA) supports the exemption for controllers that act as emergency shutdown devices. However, the commenter requests that EPA clarify that the emergency shutdown device exemption is not limited to those devices at well sites, centralized production facilities, natural gas processing plants, and compressor stations.

Response II-7-20: As natural gas-driven process controllers are only included in an affected facility if they are at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station, any natural gas-driven process controller, including emergency shutdown devices, not at these site types is not part of an affected facility. Process controllers not included in an affected facility are not subject to the rule.

Comment: Commenter (2433-EDF et al) thinks an exemption for emergency shutdown devices (ESDs) is reasonable but urges EPA to include natural gas-driven controllers used for ESDs in the affected facility definition so that EPA can impose specific requirements to ensure that operators only utilize this exemption for these controllers. EPA must then clarify what records must be maintained to allow operators the exemption. The commenter recommends that to utilize this exemption, operators must identify the precise natural gas-driven controllers needed for ESDs in their annual and subsequent reports.

Commenter (2305-Williams) states ESDs and failsafe safety valves serve a vital function at their facilities, and they must have the ability to immediately operate when activated to protect our

employees, the facility and pipeline infrastructure, and neighboring landowners and communities. The commenter asserts that these 2 types of controllers should be exempt from the affected facility definition.

Commenters (2366-BHE, 2483-INGAA) state that ESDs should be exempt. The commenters explain that this is necessary to ensure that an operator's ability to deliver natural gas safely and reliably is not compromised. The commenters also recommend that the final regulation include a pathway where an exemption or alternative can be readily approved. Ideally, this process would result in a class or categorical exemption for a defined application or process. Or it could be allowed on a case-by-case basis to ensure that the final rule does not result in egregious outcomes.

Commenter (2483-INGAA) supports that EPA has exempted ESDs from the requirement to use a zero-emitting electric-driven pneumatic controller. But, the commenter notes that the EPA has defined an ESD as a device that functions "exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event...." The commenter explains that there are gas-driven pneumatic controllers that serve dual roles: they are used for routine control of operating conditions, and they serve as an ESD. The commenter requests that EPA remove the word "exclusively" from the definition of ESDs and remove the last sentence regarding routine control of operating conditions as follows (struck out text indicates deleted text):

*Emergency shutdown device* means a device which functions ~~exclusively~~ to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. ~~For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.~~

Alternatively, the commenter (2483-INGAA) suggests that the word "exclusively" could be moved to the last sentence to clarify that pneumatic controllers that are used exclusively for routine control of operating conditions cannot qualify as an ESD. Under this alternate formulation, the definition would read as follows (underlined text indicates new text and struck out text indicates deleted text):

*Emergency shutdown device* means a device which functions ~~exclusively~~ to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used exclusively for routine control of operating conditions.

Response II-7-21: The EPA proposed and is finalizing an exemption from the process controller requirements for process controllers that are ESDs. These devices are designed to minimize the consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. In addition, if power is lost, these devices must still be able to function. It is rare that ESDs are activated, and

their emissions impact is minimal, but their functional need is necessary and critical to safe operations. Since it is not technically feasible to require zero-emissions options or to require emissions controls for these devices, the EPA determined it was best to exempt them from the rule by not including them in the affected facility definition. The EPA made this determination with the consideration that devices that function only as ESDs will seldom activate and have few emissions. As this is not the case for process controllers that are used for routine operations, it was not the intention of the EPA to exclude such process controller from the rule requirements, and we have not revised the final rule in the manner suggested. In such cases, owners/operators could add a process controller such that one functions as an ESD and the other performs normal operations. For ESDs, which have few emissions and no emissions control or monitoring requirements, the EPA considered that the limited benefit of keeping records of these devices would be outweighed by the recordkeeping burden imposed. Therefore, no recordkeeping requirements have been added to the final rule.

Comment: Commenter (2483-INGAA) states failsafe safety applications should be exempt and recommends that EPA include the following addition to 40 CFR 60.5430b and 60.5425c:

*Failsafe safety application* means a device which functions to protect personnel and/or prevent physical damage to equipment. For the purposes of this subpart, a failsafe safety application is not used exclusively for routine control of operating conditions.

The commenter (2483-INGAA) explains that intermittent pneumatic controllers, such as those used for failsafe safety applications only contribute approximately 0.4 percent of the total methane emissions for the transmission and storage segment and <0.01 percent of total methane emissions from natural gas operations. Providing an exemption for the failsafe application (e.g., where the worker and monitor valve pneumatic controller emissions are a subset of intermittent pneumatic controllers) results in emissions that are extraordinarily small, comprising less than 0.01 percent of transmission and storage segment emissions and far less than 0.001 percent of total methane emissions. Because these controllers are needed to ensure system safety and because emissions from these controllers are infinitesimal, providing a functional exemption for failsafe safety applications is warranted.

For background, the commenter (2483-INGAA) offers the following:

Control valves are used to limit pressure delivered into a system with a lower pressure rating (e.g., a compressor station process, a lower pressure pipeline, etc.). Without an extremely reliable system to protect against overpressure, facilities are at greater risk of damage, overpressure, flow interruption, and potentially even pipe ruptures. These control valves are commonly referred to as “worker” and “monitor” valves, where the worker valve provides primary pressure control, and the monitor valve provides backup to ensure “failsafe” functionality. The primary worker valve can be zero-emission (e.g., electric, air system), but a different energy source is needed for the backup monitor valve. Because high pressure gas is always available when these valves need to function (i.e., the valve is controlling gas pressure), natural gas pneumatic controllers are the only failsafe source.

These valves also must comply with PHMSA [Pipeline and Hazardous Materials Safety Administration] regulations, specifically 49 C.F.R. §192.195. That regulation requires operators to ensure that a pressure control failure or some other type of failure cannot cause both the worker valve and the monitor valve to fail to function.<sup>11</sup> Thus, the same type of system (e.g., pneumatic air, solar power, electricity, etc.) should not be used to operate both a worker and monitor valve. Doing so would put the operator and general public at risk of pipeline over pressurization when the power source fails. Because the condition managed (i.e., pipeline pressure) ensures that high pressure natural gas is always available to actuate the monitor valve, using natural gas pneumatic controllers on the monitor valve provides failsafe assurance that is not provided by other options and assures conformance with PHMSA requirements.

Evaluation of actuation by an INGAA member showed that while the worker valve may function frequently, the monitor valve actuates rarely, so the emissions implications of retaining a natural gas pneumatic for the monitor valve are inconsequential. Evaluation over a five-month period showed only one actuation of the monitor valve. For this system (i.e., two valves that may require actuation), using a zero-emission controller for the worker valve and a natural gas pneumatic for the monitor valve showed that system emissions were reduced by over 99% compared to a system that uses natural gas drive pneumatics for both controllers.

Response II-7-22: In the situation described by the commenter, in which a controller is used to protect personnel and/or prevent physical damage to equipment, the final definition of “emergency shutdown device” or “ESD” would apply. This definition, as shown below, includes stopping the flow of gas (e.g., via a failsafe device) during unsafe conditions.

*Emergency shutdown device* means a device which functions exclusively to protect personnel and/or prevent physical damage to equipment by shutting down equipment or gas flow during unsafe conditions resulting from an unexpected event, such as a pipe break or fire. For the purposes of this subpart, an emergency shutdown device is not used for routine control of operating conditions.

As the “emergency shutdown device” definition would include failsafe devices (that stop the flow of gas), if they are used exclusively for the purpose of protecting personnel and/or to prevent physical damage to equipment and are not used for routine control of operations, we have not revised the rule to otherwise address failsafe devices. The EPA excluded ESDs from the rule requirements with the consideration that devices that function only as ESDs will seldom activate and have few emissions. As this is not the case for process controllers that are used for routine operations, it was not the intention of the EPA to exclude such process controllers from the rule requirements, and we have not revised the final rule to exclude failsafe devices that are also used for control of routine operations. In such cases, owners/operators could add a process controller such that one functions as an ESD and the other performs normal operations.

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<sup>11</sup> 49 CFR 192.195(a) (requiring compliance with 49 CFR 192.199 and 192.201).

### **7.1.7 Other**

Comment: Commenter (2351-Jonah Energy) states that the proposed definition for an affected facility, "is defined as the collection of all the natural gas-driven pneumatic controllers at a well site, centralized production facility ... or compressor station."

- Operational considerations for natural gas-driven pneumatic controllers differ in both function and location. Not all pneumatic controllers are created equal. A 'one size fits all' definition does not account for all the varied uses of pneumatic controllers. Gas-actuated controllers used to regulate temperature (e.g., T-12s) do not function the same or actuate as often as gas-actuated devices that regulate dump or flow control. This may have not been taken into consideration during EPA's BSER analyses and needs to be accounted for.
- Many gas-actuated controllers do not operate 8,760 hours per year as they only operate during colder weather months when certain process equipment is necessary for winterization purposes and gas supply during the off-season is shut off minimizing the opportunity for leaks. This may have not been taken into consideration during EPA's BSER analyses and needs to be accounted for.

Response II-7-23: In the BSER analysis, the EPA used the information available regarding controller emissions. These values are averages determined from the study of many controllers, which would have included controllers used for different purposes, such as temperature and flow control. The EPA has assumed that controllers operate throughout the year, as information regarding the average annual use of controllers is not available. However, as the costs for some zero-emitting options are well below the costs at which the EPA has determined costs are reasonable considering the emissions reductions that would be achieved, the BSER determination would not change even if the controllers were not operating during winter months.

## **7.2 NSPS OOOOb and EG OOOOc BSER Control Options**

### **7.2.1 General Support/Opposition of Proposed BSER**

Comment: Several commenters (1581-Kathairos, 1609-Qnergy, 2163-Federated Hermes, 2164-Nordea, 2184-SRC Ambassador, 2190-M/H Investments, 2191-Boston Trust, 2199- RM Farmers Union, 2203-Ceres, 2206- L&G Investment, 2212-UCS, 2303-NTAA, 2347-Clarke, 2348-EWTC, 2410-CA AG et al, 2433-EDF et al) provide general support for EPA's proposed standards. Examples of some of these comments are provided below.

Commenters (1611-ELPC, 1649-Sisters of St. Francis, 2152-CALSTRS, 2156-CCGD, 2163-FHL, 2164-NA Management, 2184-LF, 2185-NY CRF, 2190-MHI, 2191-BTWC, 2199-RMFU, 2203-Ceres, 2206-LGIMA, 2209-PLS, 2212-UCS, 2236-PSR, 2242-SGI, 2285-Bailard, 2287-ICCR, 2348-EWTC, 2352-ETRPC, 2388-ExxonMobil, 2394-Earthworks, 2424-AYS, 2441-HAWC, 2459-Global Asset Management, 2461-CRS, 2766-1000 Grandmothers) express support for phasing out of polluting pneumatic controllers in favor of zero-emitting alternatives. Commenter (2388-ExxonMobil) supports devices being granted limited exemptions where technical or safety limitations exist.

Commenter (2347-Clarke) supports EPA’s proposal to require all new and existing pneumatic controllers at production, processing, transmission, and storage facilities (except certain sites in Alaska) to have zero methane and VOC emissions. The commenter notes that the EPA’s own Natural Gas STAR publications as far back as 2006 and 2011, among others, demonstrate a recognition that it is relatively cost-effective and extremely beneficial in terms of substantially reducing methane emissions to take this step. More recent reports and statements from the oil and gas industry itself, such as the following, corroborate that this is a worthwhile and achievable step.

Commenter (2433-EDF et al) also supports EPA’s proposed standards for pneumatic controllers. The standards acknowledge the variety of cost-effective zero-emitting technologies that are available to operators and give operators more than sufficient time to retrofit existing sites. In supplementary comments, commenter (3820-EDF et al and 3841-EDF et al) provided information from the implementation of process controller regulations in Colorado showing that zero-emissions options are being used there to comply with the regulations. Commenter (2303-NTAA) is pleased to see that EPA maintained the zero-emitting pneumatic equipment requirements for pneumatic controllers and expanded this requirement to include pneumatic pumps.

Response II-7-24: These comments are supportive comments on aspects of the December 2022 Supplemental Proposal that have remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2227-WEA) states VOC emissions are an especially focused issue because the Uintah and Ouray Indian Reservation area is an ozone non-attainment area. The commenter disagrees, however, that the EPA mandating zero-emissions controllers is necessary or required here and provided reasoning in the proposed Federal Implementation Plan (FIP) for requiring low-bleed pneumatic controllers rather than zero-emissions pneumatic controllers. According to the commenter, it is inappropriate for EPA, on a nationwide basis, to go above and beyond requirements deemed to be sufficient for an ozone nonattainment area.

Response II-7-25: The EPA performed analyses in determining the “best system of emissions reduction” (BSER), which is the degree of emission limitation that has been adequately demonstrated, taking into account the cost of achieving the emissions reduction and any nonair quality health and environmental impact and energy requirements. The BSER is not based on the emissions reductions necessary to reach NAAQS attainment status. For process controllers, zero-emissions was found to represent the BSER, and this is reflected in the NSPS and EG.

### ***7.2.2 Access to Reliable Electricity***

Comment: Commenter (2433-EDF et al) states that first, operators have incorrectly suggested that the feasibility of the zero-emission standard is somehow dependent on the availability of grid connection. The commenter notes that grid connection, however, does not present a barrier to widespread deployment of zero-emitting controllers. In instances where operators do not have access to the grid or grid access is cost prohibitive, the commenter states that the proposed regulation is flexible and provides operators a number of commercially available and cost-

effective options to achieve the standard. Operators that cannot access grid electricity can still use electric or instrument air systems powered by solar energy or can use natural gas-driven controllers that are self-contained or routed to a process, all of which, as discussed, are cost-effective and feasible across the U.S. Accordingly, the commenter notes that the availability of grid connection has no bearing on the reasonableness of EPA's standards.

Second, the commenter (2433-EDF et al) notes that operators have suggested that compliance with the zero-emission standard is infeasible at sites requiring large electricity demand. However, for sites that are already connected, using that connection to power electronic controllers is cost-effective across-the-board, including at sites with high demand. The Analysis Group report shows, for example, that all zero-emitting technologies at extra-large sites using 2,000 kilowatts (kW) are cost effective even when including the cost of electricity.

Response II-7-26: These comments are supportive comments on aspects of the December 2022 Supplemental Proposal that have remained unchanged in the final rule; as such, no response is required.

Comment: Several commenters report that access/reliable access to electricity is an issue. Specific comments provided are included in the following paragraphs.

Commenter (2177-Southern Ute Indian Tribe) states that due to lack of power in many remote locations, the installation of power may be cost-prohibitive, and installation of combustion-generated power may create more emissions than are being reduced. They note that construction projects on Tribal lands require permitting through the National Environmental Policy Act (NEPA) program, which can be extensive and burdensome.

A subsidiary of the commenter (2178-Riverside Energy Carbon Solutions, LLC (RCS)), Riverside Energy Michigan LLC (REM), is the largest producer of natural gas in the state of Michigan. REM operates over 5,000 Antrim shale natural gas wells. These wells are in predominantly rural areas, and access to power is not readily available. More than half of these wells employ an intermittent bleed controller to operate the lift system. Among other undesirable requirements being proposed, requiring replacement of these control valves to be zero-emitting, consistent with current proposed BSER, would be completely unreasonable. Running power to thousands of wells across hundreds of miles of forest would certainly not meet the reasonableness threshold of \$1,970/ton methane emissions reduced or less. From the commenter's own measurements, these controllers vent less than 0.003 metric tons of methane per year on average.

Commenter (2227-WEA) reports that in much of the Uinta Basin, approximately 90 percent of the pneumatic controllers in use are more than a mile from reliable electricity transmission lines, 80 percent are more than 2 miles, and 70 percent are more than 3 miles.

Commenter (2321-AED) states that the EPA's new requirement that equipment must be powered by electricity poses serious challenges to rural oil and natural gas fields that will not have easy access to electric power.



Commenters (2314-Miller Energy Company) and (2200-NuEnergy) state that to transition field equipment onto electrical power sources poses serious challenges in their rural field operations. Many rural locations do not have access to electric power. Additionally, solar power has been tried without success, and solar options are not viable nor reliable throughout Michigan's seasonal weather conditions. The number of solar-qualified days is drastically reduced in Michigan compared to other states. The commenter (2314-Miller Energy Company) has tried implementing various technology (such as tank sensors) powered by solar, and even the vendors have discouraged use based on the number of cloudy days and snow buildup.

Commenter (2314-Miller Energy Company) states that while some equipment may not require a reliable power source, many do. Power outages could cause serious environmental and safety concerns if equipment goes down unexpectedly. The proposed rules need to reflect the reality of access to alternative power sources and offer exceptions when reliable electricity is not viable.

Additionally, commenter (2314-Miller Energy Company) prides themselves at recycling their field-gas waste stream by reusing it to power their field equipment. Should the commenter be required to only use electricity, their emissions would increase as they would need to flare or vent all field fuel not used by their equipment. Plus, additional electrical energy would be consumed that would not have otherwise been needed. The commenter requests the EPA consider removing the universal requirement to use electricity as the sole power source.

Commenter (2399-GPA) states EPA should limit application to facilities with reliable access to grid power. The commenter recommends that to be "readily available" would mean that there is a nearby, operating electricity supply line with sufficient capacity for the site and would not require significant new construction by a third-party provider, such as a new tie-in or the installation of additional substations. With respect to "reliable access to electricity," the commenter recommends that this mean that a power source is not subject to frequent intermittent power losses (brownouts), as continuous power is necessary for safe, reliable operations.

Commenter (2283-Endeavor Energy) notes that many well sites in the Midland Basin are located in remote locations without access to an existing grid. Even if a grid is theoretically accessible, the commenter states that it is not always logistically feasible to connect to that grid due to issues outside of an owner or operator's control.

Commenter (2251-NAM) suggests that retrofitting of all pneumatic controllers where the site has less than 15 controllers and lacks operational access to reliable grid power is unwise. The commenter provides that, just because a local electric utility has a distribution transmission line in the same zip code does not mean that the natural gas production facility is "grid reliant". They add that this provision of the proposed rule might inadvertently make some U.S. oil and natural gas production less economically viable since the producer would have to electrify that location before it is completely known whether the natural gas meets current market value. This issue especially hurts smaller producers (often small businesses) in rural Texas, New Mexico, and North Dakota where these locations are often rural. They go on to say that the proposed requirement also presumes an abundance of electric distribution transformer equipment to install. They note, however, that there is a shortage of electric distribution transformers, and it takes approximately 45-60 months to obtain new distribution transformers. According to the

commenter, imposing new pneumatic controller requirements means electrification of many rural areas that currently do not have electricity. They contend that, given the national transformer shortage, this is not practical or wise.

Other commenters also express that weather conditions can affect access and reliability of electricity delivery. Specific comments include:

- Commenter (2248-NDPC) states harsh weather conditions often interrupt electricity delivery or redirect power demands.
- Commenter (2220-WDEQ) states there are significant concerns that using electricity to power pneumatics in such remote parts of Wyoming is not viable. The frequent frigid temperatures in the wintertime throughout the State would not allow for sufficient battery performance and operators have also raised concerns that solar technologies are not viable to implement, nor reliable enough, to provide sufficient electrical power for their site operations in the wintertime.

Commenter (3838-API) provided information regarding the number of sites without access to electrical power. Based on the results from a survey of its members, the commenter remarked that 72% of production sites, representing 59% of natural gas-driven controllers for that segment, lack access to electricity. In the gathering and boosting segment, 44% of sites representing 40% of controllers lack access to electricity. The commenter added that the transmission and storage segment had more than 99% of sites with access to electrical power. The commenter stated that due to limited access to electrical power, the EPA should reconsider BSER for pneumatic controllers, especially at existing sites.

Response II-7-27: The EPA notes that “access to electrical power” is defined as, “*Access to electrical power* means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.” Although only sites in Alaska might be affected by this definition, as all other sites must have zero emissions from process controllers, the definition makes it clear that electrical power would already need to be onsite for the owner/operator to be considered to have access to electrical power.

The EPA understands that sites with process controllers may not have access to electrical power. There are several options available to such sites to meet the NSPS and EG. These include the use of solar-powered process controllers, the use of electric process controllers powered by a generator, the use of compressed air-driven process controllers powered by a generator, and routing emissions to a process. The EPA also notes that solar-powered process controller systems include batteries that are typically sized to contain a 10-day power supply, and this battery power ensures continuous process controller operations.

The EPA also understands that permitting actions may be required when adding or changing equipment at a facility. However, such permitting is not directly required by this rulemaking and is outside the scope of this action.

Comment: Several commenters specifically highlight infrastructure issues that impact access to reliable electricity. Specific comments are provided in the following paragraphs.

Commenter (2227-WEA) notes there are several reasons why electrification is not always an option for oil and natural gas operations. The commenter explains that integration of renewables into oil and natural gas production must include sufficient planning to cover those times when renewable resources are not available. Utility providers do not prioritize the implementation of infrastructure for oil and gas sites because it is uneconomic for them to do so when they can deploy the same resources to a new subdivision and generate much more revenue. Sparsely populated areas in the west can be significantly lacking in electrical power supply, let alone reliable electrical power supply, and the challenges to expand the availability of the electrical grid can be daunting. Even more developed yet rural areas can be substantially limited in access to a reliable electrical power supply. Even where electrical infrastructure has been developed, sufficient transmission capacity often does not exist. Finding and building infrastructure to which to connect can be a challenge. Transmission lines must go through a series of steps starting with an electricity substation and follow-on steps to transform the high voltage transmission power to a useable source of electricity at the oil and natural gas site. Lack of nearby access to transmission substations adds to the remote nature of some upstream oil and natural gas sites. The commenter adds that going through the engineering, permitting, and construction process of developing the infrastructure to transform the limited high voltage electricity to oil and natural gas useable levels can be prohibitive in some cases to the implementation of electricity as an option as well as time consuming and expensive.

Commenter (2251-NAM) notes that just because a local electric utility has a distribution transmission line in the same zip code does not mean that the natural gas production facility is “grid reliant”.

Commenters (2283-Endeavor Energy, 2301-U.S. CoC) note that there are challenges including (but not limited to) right-of-way issues for placement of power lines, a landowner's right to not install power lines on their property, and/or distance from an available power line that contains sufficient power and capacity to connect the facility. For those well sites that happen to be in proximity to a grid, or where it might be technically feasible to connect them to a grid, current electricity generation in many producing regions (such as the Midland Basin) will not be adequate to accommodate EPA's proposed requirements while also balancing competing load demands. Commenter (2283-Endeavor Energy) suggests that, at the very least, EPA should remove any requirements from EG OOOOc that would require onsite electrification for compliance as it would not be technically feasible and would stress the electric infrastructure.

Response II-7-28: As explained above in Response II-7-37, the EPA notes that “access to electrical power” is defined as, “*Access to electrical power* means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.” Although only sites in Alaska might be affected by this definition, as all other sites must have zero emissions from process controllers, the definition makes it clear that electrical power would already need to be onsite for the owner/operator to be considered to have access to electrical power.

In addition, sites are not required to use electrical power from the grid. There are several other options available to such sites to meet the NSPS and EG. These include the use of solar-powered process controllers, the use of electric process controllers powered by a generator, the use of compressed air-driven process controllers powered by a generator, and routing emissions to a process.

Comment: Commenter (2227-WEA) states that power interruption brings the risk of sending control equipment into “a fail-safe condition.” According to the commenter, being dependent upon the reliability of electricity can be especially risky in rural areas. Relying on renewable energy such as solar or wind power typically involves some manner of backup generation. The intermittent nature of renewable energy requires companies to have backup electricity for those times that renewables are not available. The commenter asserts that solely relying on the intermittent nature of renewables is not an option for oil and natural gas operations since they require power on a full-time basis. The commenter adds that the need for emissions- generating backup can significantly affect the economic feasibility of using renewables.<sup>12</sup> Backup power is most likely to come in the form of onsite generation, which is discouraged by regulation in some regions, or the local power grid.

Response II-7-29: Where an owner/operator is concerned about the reliability of electricity, solar power, or wind power, there are other options available for compliance with the process controller requirements. The owner/operator can use a generator to power either electric controllers or compressed air-driven controllers, use nitrogen canisters to provide compressed air, or route emissions to a process. The EPA is not aware of any situations where a generator of the size needed to power process controllers at a site would not be allowed by regulators.

Comment: Commenter (2220-WDEQ) states that Wyoming is dedicated to protecting the Greater Sage-Grouse, which lives in the sagebrush steppes of our State. Wyoming has devoted significant resources over the years towards developing a conservation plan for this species. The commenter explains that one of the important safeguards for this species is protection of its core habitat areas. According to the commenter, the level of electrical infrastructure needed to meet the requirements for pneumatics in the supplemental proposal would have potential impacts on portions of the Greater Sage-Grouse’s core habitat, as well as issues pertaining to deer and antelope migration corridors, and other species that inhabit Wyoming’s lands.

Response II-7-30: As explained above in Response II-7-37, the EPA notes that “access to electrical power” is defined as, “*Access to electrical power* means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power.” Although only sites in Alaska might be affected by this definition, as all other sites must have zero emissions from process controllers, the definition makes it clear that electrical power would already need to be onsite for the owner/operator to be considered to have access to electrical power. Therefore, the EPA does

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<sup>12</sup> “New Mexico Methane Advisory Panel Technical Report,” New Mexico Environment Department (NMED) and New Mexico Energy, Minerals and Natural Resources Department, 2019.

Note: This report was generated as a collaboration between NGOs, industry, and the state. It is not an official position document of NMED.

not expect there to be expansion of electrical infrastructure to meet the requirements for process controllers.

Comment: Commenter (2399-GPA) states that, despite the importance of access to reliable grid power, the proposed EG OOOOc does not recognize the clear distinction between existing facilities and truly new facilities, which have some flexibility in where they will be sited, and existing sources that do not. To address existing sources' lack of flexibility, the commenter proposes that EG OOOOc requirements be subject to a site-specific technical and cost effectiveness review for connecting to the power grid or using onsite power generation, such as solar power or natural gas- or diesel-fired generator. It would also consider the costs of conversion, such as the installation of additional instrument air headers and piping. This type of review would be similar to the review for pneumatic pumps. If the review determines that these options are either technically infeasible or not cost-effective (e.g., more than \$5,540 per ton of VOC or \$1,970 per ton of methane), then the owner or operator should be permitted to use natural gas-driving continuous low-bleed and intermittent-bleed controllers.

Response II-7-31: In the analyses performed in determining the BSER, the costs of installation of equipment at an existing site were included. For some equipment types, such as compressed air systems, these costs were assumed to be higher at existing sites than new sites due to the need to work around and with the configuration of existing equipment. With consideration of these costs, the EPA still found that zero-emissions represents the BSER at existing sites and that the costs are reasonable considering the emissions reductions that will be achieved.

Comment: Commenter (2283-Endeavor Energy) notes that, because access to reliable electricity may be a problem for existing sources, they suggest that the EPA remove the pneumatic controller and pump requirements for existing sources, or at the very least consider the effects that its proposed requirements would have on the grid infrastructure, and at the very least analyze these costs before finalizing any requirements.

Response II-7-32: As explained above in Response II-7-37, the EPA notes that "access to electrical power" is defined as, "*Access to electrical power* means commercial line power is available onsite, with sufficient capacity to support the required power loading of onsite equipment, and which provides reliable and consistent power." Although only sites in Alaska might be affected by this definition, as all other sites must have zero emissions from process controllers, the definition makes it clear that electrical power would already need to be onsite for the owner/operator to be considered to have access to electrical power. Therefore, the EPA does not expect there to be expansion of electrical infrastructure to meet the requirements for process controllers or for the electrical grid to be impacted by the process controller requirements.

In addition, if an owner/operator is concerned about the reliability of electricity, solar power, or wind power, there are other options available for compliance with the process controller requirements. Such options include the use of a generator to power either electric controllers or compressed air-driven controllers, use of nitrogen canisters to provide compressed air, or routing emissions to a process.

### 7.2.3 Solar

Comment: Several commenters expressed concerns over the limitations to the use of solar driven pneumatic controllers. Specific comments are provided in the following paragraphs.

Commenter (2227-WEA) states that solar controllers are limited by the availability of sunlight, average ambient temperature, and the prevalence of fog or dust, making them unreliable. In areas like the Uinta Basin, where fog can sit for several weeks, cold weather can also hamper the use of battery power for backup.

Commenter (2399-GPA) reports that the Carbon Limits report focuses on the reliability of solar power systems in colder climates, not areas with limited sun exposure. As a result, the commenter points out that the Carbon Limits study does not address the reliability of solar-powered systems in areas with limited sun exposure, such as West Virginia, or in canyons and mountain valleys.<sup>13</sup> [Discussed further below.]

Commenter (1609-Qnergy) has observed that the intermittency and sensitivity to weather conditions of solar generation, in addition to low availability during the winter, especially in high latitudes, limit adoption. The commenter has installed more than a hundred instrument air units in Alberta and British Columbia, which meet the relevant zero emission requirements. However, despite many attempts, solar generation have not seen a broad adoption in Canada. The commenter itself has considered commercializing a solar solution for small sites and concluded that it is applicable only for powering single controllers but not as a broad instrument air solution.

Commenter (2321-AED) reports that solar alternatives are not reliable in Michigan weather conditions, which could cause a serious problem at a well site if equipment goes down. The commenter states that the proposed rules need to reflect this reality and offer exceptions to this requirement when reliable electricity is not viable.

The commenter (2321-AED) is also concerned that the necessary resources for potential work to achieve compliance will not be available in terms of manpower and battery equipment additions. The commenter provides that it has been a struggle to get work accomplished in the field and the commenter is afraid of how much work they will need to do and who is going to do it when it needs to be done.

Commenter (2399-GPA) note that, regarding the snow covering of solar panels, EPA did not attempt to calculate how much sun exposure is diminished by vertical placement, whether this could also prevent ice accumulation, how much power generation would be diminished through snowpack, or whether solar panels could work with any placement in areas prone to blizzards and other serious winter weather.

Commenter (2428-API) states that snowfall is prevalent at its facility and will reduce efficiency of the optimally angled panels. According to the commenter, vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances given the climate, wind, and

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<sup>13</sup> EPA has properly recognized this as an issue by proposing to exempt Alaska from this requirement.

remote nature of these sites. Commenter (2351-Jonah Energy) recommends that the EPA consider that a redundant system would be required in some instances due to time periods where solar power generation would not be sufficient to satisfy power requirements to production facility operations. The commenter explains that solar panels can be covered with snow and ice or there could be periods of cloudy weather where solar power generation is not sufficient to keep batteries charged enough to supply the amount of power necessary to run operations. Reliability is incredibly important as failure of devices may lead to serious safety and environmental incidents. Absent line power, diesel-fired generators and/or natural gas-fired generators are required to be used as a source of power when solar-powered/battery systems are not operable. The commenter notes that they operate in a basin subject to ozone formation and therefore trading one pollutant for another pollutant may negatively impact the local airshed.

Response II-7-33: Commenters contend that solar power is not a feasible option to use for controllers at some sites. Considering that the electrical power needed by each controller is low,<sup>14</sup> the EPA expects that a solar power system could be sized with the appropriate number of panels and batteries to power process controllers at most, if not all, sites. However, the use of solar power is not required, and an owner or operator may choose not to use solar power for any reason. Another option determined to be cost-effective at all sites was the use of a generator to power electric process controllers, and the use of a generator to power a compressed air system was cost-effective at larger sites. Other options available to meet the zero-emissions standard at sites without grid power and without using solar power include self-contained process controllers, or routing emissions from controllers to a process, although costs were not evaluated for these two options.

Comment: Commenter (2399-GPA) states the Carbon Limits report authors relied on interviews with three technology providers and two oil and gas companies, without making any inquiry into whether the technologies could be applied to midstream gathering and boosting operations, which have a larger footprint and substantially greater power needs. The economic models supporting cost-effectiveness are also based on only three well pad site configurations, which are not comparable to gathering and boosting stations that require more powerful air compressors to generate instrument air at 400 standard cubic feet or more. The commenter argues that the EPA should not force the industry-wide adoption of technologies based on only 22 cases of adoption over three countries, which is too small of a sample to support a determination that these technologies are technically feasible and cost-effective nationwide and in so many varying applications. The commenter adds that EPA also lacks experience with the operational use of solar-powered controllers on the scale being considered, and that the agency's reliance on the Canadian provinces of Alberta and British Columbia as examples of successful adoption of non-emitting controller regulations is misleading.

The commenter (2399-GPA) adds that nothing in the December 2022 proposal or the Carbon Limits report addresses the fact that reliance on solar power leaves sites subject to the weather and could be effectively shut down for days. The commenter reports that power loss at a midstream site can disrupt the entire upstream and downstream supply chain and raises

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<sup>14</sup> Estimate of 0.08 amps/controller in Carbon Limits. (2016) Zero emission technologies for pneumatic controllers in the USA - Applicability and cost effectiveness.

environmental consequences such as additional emissions and the need to flare or vent gas if downstream equipment is not available.

Response II-7-34: While using solar power to provide energy for process controllers is one option available for compliance with the NSPS or EG, the use of solar power is not required. Information provided in a supplemental comment<sup>15</sup> indicates that over half of U.S. gathering and boosting site have access to electrical power, and that the average number of process controllers at gathering and boosting sites without access to electrical power is 17. In our analyses for BSER, we estimated the costs of a generator to power electrical process controllers at a site with 20 controllers and found that the costs were reasonable, considering the emissions reductions that would be achieved from 20 process controllers. Other options include the use of a generator to power a compressed air system, the use of canisters of compressed nitrogen to power controllers, using self-contained controllers, or routing controller emissions to a process.

Comment: Commenter (2428-API) reports that the land requirement for the use of solar for many sites is likely to be between 0.6 – 1.5 acres. Key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time-consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area. Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.

The commenter (2428-API) urges EPA to also consider other factors including:

- the cost of land acquisition; right-of-way and easement concerns/limitations; projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

Response II-7-35: If an owner/operator chooses to use a solar system to power the process controllers on site, only enough energy needs to be generated to power the process controllers, not all the operations at the site. As the average power needed per controller is approximately 1 watt, a 140-watt solar panel is capable of powering several process controllers. In addition, solar panels can be vertically stacked on stands so they take up less space. Due to the relatively few solar panels needed to power process controllers and the space-saving solutions available, the EPA does not anticipate land use or infrastructure problems associated with the use of solar systems.

#### ***7.2.4 Electric Controllers***

Comment: Commenter (2383-BH) states a power failure in a singular electrical source could cause failures in any valves drawing from that power supply, including potentially both the

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<sup>15</sup> API – AXPC Supplemental Comment to EPA Regarding Pneumatics.



primary and backup valves in a single station. The commenter also states that in the absence of backup power supplies, electric actuators could be designed to close in the event of a power loss, but this goes against traditional design philosophy for gas pipelines/distributors in the U.S., where the goal in the past has been to avoid shutting off the gas supply in any but the most extreme circumstances.

Response II-7-36: There are many options available to owner/operators for compliance with the process controller standards. We note that emergency shutdown devices (ESDs) are not included in the process controller affected source definition and are not subject to the process controller requirements. If an owner/operator chooses to use electric process controllers and is concerned about power failures, an ESD could be installed to protect personnel and/or prevent physical damage to equipment. Other options include using generators, which are assumed to be reliable power sources, to power compressed air systems or electric controllers, using nitrogen canisters to power process controllers, using self-contained process controllers, or routing process controller emissions to a process.

Comment: Commenter (2383-BH) states electric actuators on the market today are not intended for continuous use and may not be suitable for applications where continuous modulation is required (pneumatic actuators are suitable for this service).

Commenter (2227-WEA) states electrical controllers can generally only be used to control valves. So even in situations where electricity is available, often it won't be sufficient to reliably keep the entire facility operating safely.

Commenter (2399-GPA) states electric controllers tend to have inadequate duty cycle ratings and their torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions to maintain a set point.

Response II-7-37: The EPA notes that a wide range of electrical controllers are on the market today, which have addressed the limitations of previously available electrical process controllers. However, the use of electrical controllers is not required for compliance with the standards, and an owner/operator may choose another option, such as the use of a compressed air system or nitrogen canisters to power pneumatic controllers.

Comment: Commenter (2399-GPA) reports that a controller failure is a serious concern for midstream operations, which have significant unmanned facilities. Hence, they report that any repair requires sending personnel out to those facilities that are frequently found in remote locations. The commenter states controller failures can result in overpressure events, releasing far more methane than that saved by electrically actuated controllers.

Commenter (2248-NDPC) explains that reconfiguring the way controllers operate using drivers such as electricity and instrument air introduces increased reliability issues. With electricity, the harsh weather conditions often interrupt electricity delivery or redirect power demands. They add

that, with instrument air, additional equipment, an air compressor, is required and compressor failures will interrupt delivery of instrument air.

Response II-7-38: The EPA has no information to suggest that electrically actuated controllers have failures more often than pneumatic controllers. In contrast, the information available to the EPA suggests that electronic systems are more reliable than gas-driven pneumatic control systems. According to one report, operation of gas-driven systems with even slightly wet gas can lead to condensation issues, which over time will impact the performance of the system.<sup>16</sup> This report also indicated there can be corrosion issues with sour gas used for pneumatic controllers and pumps. The EPA also has no information, nor does the commenter provide any information, to suggest that air compressor failures are common or present an issue for the operation of site equipment.

### **7.2.5 Generators**

Comment: Several commenters (2177-Southern Ute Indian Tribe, 2220-WDEQ, 2252-PAW, 2305-Williams) indicate that secondary criteria emissions from the use of gas-fired generators/combustion devices may occur.

Commenter (2220-WDEQ) states even though gas-powered generators would have to undertake state permitting process, their operation nevertheless could result in increased cumulative nitrogen oxide (NO<sub>x</sub>) and VOC emissions. Gas-powered generators would run at all times as opposed to the intermittent function of pneumatics that periodically vent emissions, which is problematic for marginal ozone nonattainment areas such as Upper Green River Basin (UGRB).

Commenter (2252-PAW) states diesel- and natural gas-fired combustion would generate criteria pollutant emissions and other hazardous air pollutants (HAP). Some companies in Wyoming operate in an ozone non-attainment area and therefore trading one pollutant for another pollutant may negatively impact the local airshed and prevent the region from re-attaining ozone attainment status. Therefore, the commenter suggests diesel-fired generators and/or natural gas-fired generators should be expected to be used as a source of power when solar-powered/battery systems are not operable and line power is not available as an option.

Commenter (2177-Southern Ute Indian Tribe) states there is not an environmental benefit in increasing overall emissions to reduce the potential of methane emissions from pneumatic equipment. Due to the difficulties in getting infrastructure projects approved through the NEPA process on Tribal lands it is likely that the regulations would result in many small natural gas-fired engines being installed. This has the possibility to effect other regional pollutants, such as ozone, and need to be taken into consideration.

Commenter (2305-Williams) states that these generators will also have secondary emissions impacts greater than what the EPA has provided in the December 2022 supplemental proposal for a 200-brake horsepower (bhp) unit.

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<sup>16</sup> Carbon Limits. Zero Emission Technologies for Pneumatic Controllers in the USA. Applicability and Cost Effectiveness. August 1, 2016.

Response II-7-39: Generators, which produce power by burning a fuel, such as natural gas or diesel, will generate a small amount of emissions from this process. As we assumed some sites would choose to install an electric generator to power compressed air-driven or electrical process controllers, we estimated the emissions that would be created by such generators. For this analysis, we included natural gas generators of 5 to 10 horsepower, which should be sufficient sizes to accommodate 4 to 100 process controllers. We estimate that a natural gas-powered generator would produce between 0.006 and 0.025 tons of VOC and between 0.15 and 0.6 tons of NO<sub>x</sub> per year, depending on the number of controllers and the size of the generator needed to power the controllers. However, the emissions reduced through the use of zero-emission process controllers powered by such generators would range from 1.7 to 41. Tons of VOC and 6 and 150 tons of methane per year. Therefore, we found the emissions created by generators to be relatively small and are outweighed by the emissions reductions that would be reduced from the process controllers.

Comment: Commenter (2399-GPA) states both diesel- and gas-fired generators should be allowed. The commenter urges EPA to confirm in the final rule as it recognized in the November that diesel- and natural gas-fired generators may be used to supply onsite power for instrument air systems or other electrical source needs (e.g., electric valves, pumps, heat tracing, etc.). Although natural gas-fired generators are more commonly used, operators need flexibility in choosing which fuel source provides the more reliable and safer power generating option for the specific location. Issues affecting diesel- versus natural gas-fueled generators may include horsepower requirements, fuel quality, site elevation, access to fuel, available space for installation (diesel fuel requires additional storage vessel(s) for onsite fuel storage), etc.

Response II-7-40: The final rule does not include any restrictions for generators used at any oil and natural gas sites.

Comment: Commenter (1609-Qnergy) notes that EPA states the following:

The EPA recognizes that if owners and operators elect to comply by installing and operating a generator, there will be secondary emissions generated from the fuel combustion. However, we also point out that, for a site with 100 controllers (a size cited by the commenter requiring a large instrument air system), these secondary emissions would represent approximately a 77 percent decrease in CO<sub>2</sub> equivalent emissions and a 96 percent decrease in VOC emissions from a site with 25 low bleed and 75 intermittent bleed controllers.<sup>17</sup>

The commenter (1609-Qnergy) believes that the EPA's values are too conservative. They provide that a 100-controller site, as mentioned in the EPA example, will consume nearly 12 standard cubic feet per minute (scfm) of instrument air. The commenter adds that the instrument air system will abate about 126 tons per year (tpy) of methane. The commenter states that the abatement efficiency is 99 percent or higher, and the emissions are 10-30 tons of CO<sub>2</sub>-equivalent (tCO<sub>2e</sub>) per year and the abatement 120 tons of methane, which is equivalent to nearly four thousand tCO<sub>2e</sub> per year.

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<sup>17</sup> See Proposed Rule.

Response II-7-41: We agree with the commenter that the abatement in CO<sub>2</sub>-equivalent emissions is over 99% when zero-emissions controllers are used and powered by a natural gas-fired generator. As detailed in the final TSD, for a 100-controller site in the production segment, the EPA's estimate of methane emissions is approximately 150 tons per year. This is based on the number of low-bleed and intermittent vent process controllers expected at the site, the emission factors for those process controllers, and the proportion of natural gas that is methane for the production segment. We assume 100% of these emissions would be reduced with zero-emissions process controllers. Using a methane global warming potential of 25 times that of CO<sub>2</sub>, the CO<sub>2</sub>e is 3,750 tons of emissions reduced through zero-emitting controllers. The EPA estimated the global warming potential of GHG emissions from a 20 HP compressor at 23 tons CO<sub>2</sub>e. The resulting CO<sub>2</sub>e saved is approximately 3,727 tons, which is over a 99% reduction.

### ***7.2.6 Instrument/Compressed Air Systems***

Comment: Commenter (1609-Qnergy) requests EPA to clarify explicitly that instrument air systems with zero methane emissions in the power generation stage are considered BSER for pneumatic controller applications.

Response II-7-42: The EPA confirms that process controllers powered by instrument air and that do not use natural gas to drive the process controller or its valves are considered the BSER. Any air compressors or generators used to power process controllers are not part of the process controller affected facility and are not regulated by the process controller requirements.

Comment: Commenter (2258-MSD) explains that 40 CFR 60.5365b(d) excludes pneumatic controllers from applicability only if they function as emergency shutdown devices or are not powered by natural gas. EPA then goes on to suggest operators meet the "zero emissions" standard by utilizing alternatives such as compressed air or electrically-driven devices powered by line power or solar. The are concerned that no option is provided to allow the operator to conduct a study to demonstrate the feasibility of these alternatives. The commenter recommends excluding devices which cannot operate on compressed air due to safety concerns that the potential introduction of air to the gas stream may create. The commenter also suggests allowing evaluation of technical and economic feasibility of these options.

Response II-7-43: As many sites throughout the states of Colorado and New Mexico as well as sties in the Canadian provinces of Alberta and British Columbia have successfully switched to using zero-emitting process controllers, the EPA has determined that there are technically feasible zero-emitting options that have been adequately demonstrated. The EPA also performed analyses of the costs for several zero-emissions options and determined that the costs of several available options to achieve zero emissions from process controllers are reasonable, considering the emissions reductions that would be achieved. Therefore, with consideration of both the technical and economic feasibility of zero-emissions process controllers, the EPA determined that zero-emissions represents the BSER, and this reflected in the NSPS and EG.

Comment: Commenter (2428-API) notes that during construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add

necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g., limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

Commenters (2428-API, 2227-WEA) note that existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels. To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to NEPA, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

Response II-7-44: Air compressors and generators of the size needed to power process controllers are generally not large systems that require much space. However, it may be possible in some limited instances that owners/operators of existing sites wishing to use a compressed air system may need to move equipment or buy or lease more space to accommodate the new system. In such instances, owner/operators may choose to make these accommodations or may choose to use another of the several compliance methods available.

### ***7.2.7 Self Contained/Route to Process***

Comment: Commenter (2211-Lambda Energy) states zero bleed devices are impractical in many situations in northern climates such as Michigan, with limited electric service and diminished solar power due to indirect sunlight and snow cover in Winter. In such situations, the zero-bleed devices are an unnecessary and ineffective requirement that is not justified by the marginal potential benefits. The commenter notes that, where zero bleed devices are used, the proposed increased monitoring is duplicative and unnecessary, since by design the zero bleed devices do not allow emissions. The commenter recommends that the EPA consider retrofitting pneumatic devices to non-emitting devices as a reasonable alternative to a new technology (zero bleed) not widely used or available in this industry, and with unknown effectiveness, costs, or availability.

Response II-7-45: As zero-emitting process controllers was determined to be the BSER, the NSPS and EG reflect this determination. The EPA notes that process controllers that are not powered by natural gas are not included in the affected facility definition and the final rule does not require owner/operators to perform recordkeeping or reporting for them. In addition, owner/operators may comply with the EG for existing sources by converting natural gas-driven pneumatic process controllers to compressed air or nitrogen-driven controllers. Other options available for compliance include the use of electrical controllers, self-contained controllers, or controllers routed to a process.

Comment: Commenter (2326-AXPC) states that current requirements do not articulate repair or contain delay of repair provisions or timelines. The commenter explains that self-contained pneumatic controllers would more commonly occur on pressure control valves, where the

operator would likely need to shut-in the well or shutdown equipment to conduct any sort of repair (if any were found). The commenter suggests that repair timelines in 40 CFR 60.5397b(h) and specifically the delay of repair provisions as described in 40 CFR 60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers. Commenter (2428-API) provides similar comments.

Response II-7-46: Delay of repair provisions are more appropriate for equipment that can still function with the potential for only small amounts of emissions until repairs can be made. For self-contained process controllers that are not operating as designed or if emissions are not directed, as designed, into downstream piping, repairs to the equipment should be made as soon as possible. For process controllers that are found to be leaking through a fugitive emissions survey, the repair and delay of repair provisions would apply.

Comment: Commenter (2399-GPA) suggests that the EPA incorrectly assumes no emissions would be associated with routing pneumatic controller emissions to a process. The commenter provides that the compressor would result in direct emissions from a gas-fired engine driver or in indirect emissions from an electric driver. Either way, they report that air emissions would be created to capture these pneumatic streams and send them to a process stream.

Response II-7-47: The EPA recognizes that if owners/operators comply by installing and operating a generator, there will be secondary emissions generated from the fuel combustion. However, as there would be no direct emissions from the process controllers themselves, they are referred to as zero-emissions controllers.

Comment: Commenter (2326-AXPC) notes that while it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a vapor recovery unit (VRU) is necessary if no such lower-pressure destination exists or is of limited availability. They report that the installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Further, as production declines, the commenter notes that there may be insufficient low-pressure gas to keep VRU systems online, leaving pneumatic controller vent gas with no downstream process destination. Where downstream process pressure exceeds vent gas pressure, the commenter states that pneumatic controller vent gas cannot feasibly be routed to a downstream process without compression.

Commenter (2177-Southern Ute Indian Tribe) states that routing vapors to a process likely requires some kind of compression to increase the pressure of the vapors from near atmospheric, to something higher than the pressure of the process they are being introduced into. In many instances they report that this will require additional equipment to be installed, resulting in an increase in facility emissions, and should be taken into consideration when requiring these types of controls.

Response II-7-48: The EPA recognizes that the use of a VRU is likely necessary for process controller vent gas to be introduced to a downstream process. We have accounted for the costs of a VRU in our analyses of the control options available as well as the emissions that would be produced from the electricity used to power a VRU.

Comment: Commenter (2391-Chesapeake Energy) supports routing pneumatic controllers to an existing process where that is an available, technologically feasible, and cost-effective option, and requests that EPA maintain routing to control as an option.

Response II-7-49: The EPA has retained routing controller emissions to a process as a zero-emissions option in the final rule.

Comment: Commenter (2383-BH) asserts that pneumatic controllers/positioners that capture natural gas, either for reinjection into the pipeline or for use by ancillary equipment, should not be restricted. Such systems may require a provision whereby they may be allowed to bleed gas to maintain function when conditions do not allow gas to be reinjected into the pipeline, though reasonable guidelines/limitations may be applied here.

Response II-7-50: For natural gas-driven process controllers routed to a process or a pipeline to have zero emissions, they must continuously have all emissions routed to that process or pipeline and not have emissions to the atmosphere. Therefore, the EPA is not including provisions in the final rule to include bleeding of natural gas to the atmosphere at any time.

Comment: Commenter (2433-EDF et al) agrees that it is reasonable to include natural gas-driven routed to a process and self-contained controllers under the proposed standards. Though grid-powered, solar, and instrument air controllers are all readily available and cost effective, and operators can replace their fleets within EPA's proposed timeline using non-natural gas-driven alternatives, they believe that allowing routed and self-contained controllers provides operators with more technological flexibility. If EPA does permit the use of these controllers, they assert that it must (as it has proposed) apply protective leak monitoring requirements. Specifically, they state that EPA should ensure that natural gas-driven controllers (even if self-contained or routed to a process) are inspected quarterly with optical gas imaging (OGI) cameras (or the equivalent alternative).

Response II-7-51: The final rule includes provisions for the monitoring of leaks from natural gas-driven process controllers. For self-contained process controllers and for the closed vent system for controllers with emissions routed to a process, initial and quarterly monitoring is required using OGI or EPA Method 21.

### ***7.2.8 Route to Control***

Comment: Several commenters provide insights on industry practices related to routing emissions from pneumatic controllers to a control device. Examples of specific comments received are provided in the following paragraphs.

Commenter (2227-WEA) states mechanical controllers are not reliable and can't be used in higher pressure implementations, and therefore, in situations where control devices and flares are adequate at reducing methane emissions by 95 percent, routing to control should be allowed.

Commenter (2247-OH EPA) notes that many operators today route emissions from some pneumatic bleed controls to existing processes or to the flare for control. The commenter states

that the requirement for all controllers to be zero bleed seems too strict when the existing controls are almost equivalent.

Commenter (2248-NDPC) states that routing to control can reduce the emission by at least 95+ percent and can be achieved with fewer supply chain issues. The commenter provides that Colorado and New Mexico have taken this approach, and it seems reasonable.

Commenter (2258-MSD) reports that many of its member companies currently utilize existing control technologies to reduce pneumatic vent emissions. The commenter notes that the proposed regulation allows 95 percent control as an option for other source categories. In the case of site modifications, they contend that it may not be feasible to route pneumatic vents to existing processes; therefore, some new beneficial process may need to be installed, potentially with the risk of adding new emissions. Also, considering the difference in volume between pneumatic sources and others, such as storage vessels, 95 percent control of pneumatic venting should be considered. According to the commenter, this option is also critical for existing pneumatic devices that, as noted above, are currently controlled. They conclude by saying that requiring a zero-emission standard for units already controlled by 95 percent or more requires the same capital and annual investment, but with little additional emission reduction over the baseline.

Commenter (2326-AXPC) notes that the EPA conservatively assumes a control device will achieve only 95 percent reduction. In many cases, the commenter provides that the actual performance of a control device exceeds 98 percent control. The commenter asserts that the EPA's analysis fails to account for the cost-effectiveness of the incremental 5 percent of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device. Commenter (2428-API) provides similar comments.

Commenter (2446-IPAA) contends that the EPA's exclusion of routing to control contradicts Subpart W and is misleading, mischaracterized, and inaccurate, at best AND willfully exaggerates emissions from pneumatic devices with clear undertones of a political agenda, at worst. In Subpart W, the commenter states that the EPA acknowledges that historical greenhouse gas (GHG) inventories, including those from the 2021 GHG Inventory (GHGI) for 2019 emissions, are significantly overstated. The commenter provides that emissions are overstated by approximately 35 percent at least and over 90 percent or more at most for intermittent-bleed pneumatic devices, which represent most of the pneumatic devices in operation within the petroleum and natural gas system segments today. As such, a 5 percent difference in emission reduction by allowing the use of existing or new control devices is hardly a "significant increase" and they believe should absolutely be an acceptable alternative BSER.

Commenter (2326-AXPC) proposes that, if EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU. Also, they propose that an operator need not install a control device for the sole purpose of complying with the pneumatic controller standards if there are less than four individual natural gas-driven pneumatic controllers that emit or may emit vent gas to atmosphere.



Commenter (2403-PAO) reports that, in many situations, onsite control devices exist that would be a cost-effective solution. The commenter provides that the EPA has requirements for control devices to obtain a 95 percent reduction in methane and VOCs emissions. Even, according to the commenter, EPA acknowledges that this is a viable option to achieve emission reductions from natural gas-driven pneumatic controllers.

Commenter (2391-Chesapeake Energy) states that they invested heavily in reducing methane emissions from controllers and in many instances, routing to controls was not only the most cost-effective means of capturing emissions but the only feasible option. They report that, in some cases where both routing to process and routing to control are possible, the distance between pneumatic devices and process units makes this option infeasible or cost prohibitive. Even if it were possible to route emissions over longer distances to a process unit, they suggest that this would increase the risk of leaks along the way. In these cases, physically shorter routes reduce the chance for leaks that might completely offset the marginal benefit of routing emissions to a process unit rather than to a control device.

Response II-7-52: We evaluated the use of control devices achieving 95 percent control in our analyses for the December 2022 Supplemental Proposal, and this control option was determined not to be the BSER and was not used to develop the process controller standards for the NSPS or the presumptive standards for the EG. For the final rule, the EPA refreshed its analysis of the costs and emissions reductions associated with the identified emissions reductions options, which included using updated emissions factors and cost information for emission reduction techniques and technologies. Zero emissions from process controllers was shown in both the analyses conducted for the December 2022 Supplemental Proposal and the refreshed analysis conducted for the final rule to be technically achievable and cost-effective at all model plant configurations through several available options, including the use of electrical controllers powered by electricity from the grid, solar power systems, and generators. Other zero-emissions process controller options are available that are technically achievable and cost-effective for some sites include, but are not limited to, pneumatic controllers powered by compressed air using electricity from the grid, electric generators, or compressed nitrogen canisters; routing controller emissions to a process; and using self-contained process controllers. Since all of these options achieve a rate of zero methane and VOC emissions, compared to an emission rate of up to 5 percent of the baseline emissions through the use of a control device, we have not changed our determination that a zero-emissions option is the best system of emissions reductions. However, when developing state plans for the implementation of the EG for existing sources, States have the ability to apply a less stringent standard in accordance with 40 CFR 60.24a(c) when “Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.” If a state can demonstrate that the costs necessary for a particular source or class of sources, such those with emissions already controlled by 95 percent or greater, to switch to a zero emissions option is not reasonable considering the emissions reduction that would be achieved, the state could apply an alternate standard for such sources.

### ***7.2.9 Nitrogen-Powered Controllers***

Comment: Commenter (1581-Kathairos) reports that their nitrogen-powered controller system solution for pneumatics can be quickly scaled across industry. They provide the following as support:

- The commenter has a contractual agreement with U.S.-based Chart Industries, a leading manufacturer of cryogenic industrial gas products. Chart Industries has the capacity to produce thousands of specialized nitrogen tanks every month and can scale up as needed (they did this with oxygen tanks during the COVID-19 pandemic).
- No supply chain concerns: the system has few parts, and all tanks are manufactured in the U.S.
- Nitrogen supply is readily available, with air separation facilities located in oil and gas producing regions across the U.S. With air being the main feedstock, there are no concerns of supply issues or price fluctuation.
- Simple tie-ins, tanks can be installed and tied-in in half a day.
- Nitrogen distribution networks are already being established in the Marcellus (WV, PA, OH), Permian (TX, NM), D-J (CO), Haynesville (LA, TX) and Bakken (ND) basins (see Appendix B of their comment letter).

The commenter also states the use of nitrogen in their nitrogen-powered controller systems provides a highly simple and reliable solution to eliminating the practice of routine methane venting. They provide the following as support:

- Nitrogen systems require no on-site power, relying solely on thermodynamics.
- No grid connection or solar set up is necessary, only road access is required.
- Nitrogen systems can convert all pneumatic devices simultaneously, as all devices are tied into a single nitrogen tank.
- No need to replace existing pneumatic devices; the nitrogen system simply ties in to existing systems, replacing methane for instrument power.
- With level sensors and on-site telemetry units, nitrogen systems provide extremely accurate data on methane mitigated. Given that it's a closed loop system, by tracking nitrogen consumption and applying a gas equivalence ratio, we can determine exactly how much methane otherwise would have been emitted. All this data is tracked in real-time and uploaded to the commenter's cloud-based portal for producers to use for compliance and reporting purposes.

Response II-7-53: Although the EPA did not specifically include the use of nitrogen canisters as a zero-emissions option in our BSER analyses due to a lack of nation-wide availability, we acknowledge that it is a technically feasible option and may be cost-effective for some sites to use for powering pneumatic process controllers.

### ***7.2.10 Regional Area Considerations***

Comment: Several commenters (2220-WDEQ, 2225-WESTAR, 2227-WEA, 2297-Petro-Vest, 2483-INGAA, Others) specifically point out regional rural infrastructure and weather considerations as impacting access to reliable electricity.

Commenter (2225-WESTAR) states there are oil and gas facility locations in Montana, Wyoming, and North Dakota that are extremely remote, that do not have access to electrical power, and experience extreme temperature shifts that make certain technology like solar and/or batteries infeasible.

Commenter (2227-WEA) expresses that regionally differing economic, operational, and development parameters in the lower 48 states, just as with Alaska, play a key role in the resulting economic impacts that oil and natural gas rules create, including revenue and costs, and the feasibility of the implementation of proposed rules such as NSPS OOOOb and EG OOOOc. EPA's publication describes a framework where all gas-driven pneumatic controllers would be eliminated from new and existing sources, except for those controllers in Alaska where electricity and solar power is not available. At the facilities in Alaska, low-bleed pneumatics would be required. The commenter believes that the EPA has not adequately demonstrated the reasoning for the equivalent criteria not being extended to the lower 48 states. The comments notes that the EPA's reasoning is particularly perplexing given the availability of existing reliable electric power throughout the Alaskan oil fields required to operate well sites in cold temperatures and dark conditions.

Commenter (2220-WDEQ) states Wyoming requests the same exemption as provided to pneumatic controller designated facilities located at a site in Alaska. The commenter provides that the EPA's rationale for providing such an exemption is that there are facilities in Alaska that do not have access to electrical power due to Alaska's remote geography and the infeasibility of solar or other options. The commenter explains that Wyoming's geography and climate are similarly remote in many parts of the state and operators run into the same infeasibilities as in Alaska. According to the commenter, it is unfair for EPA to provide such an exemption specifically for sites in one state when there are other states that face essentially the exact same challenges. The commenter also requests that EPA consider the harsh winter conditions in Wyoming with regards to how it poses compliance timing challenges in certain instances. They explain that there are potential situations where the frigid winter temperatures might not allow certain sites to perform required compliance duties within a 30-day period because the temperatures are so cold that it would require an operator to shut in a well in order to undertake compliance activities. Put simply, they assert that a "one-size-fits-all" rule does not account for these meteorological or geographical challenges and EPA should take this into consideration when revising the supplemental proposal.

Commenter (2483-INGAA) states EPA believes that are no sites outside of Alaska where it is infeasible to (1) have electric controllers powered by the grid or by solar power; (2) have instrument air systems powered by the grid, a generator, or by solar power; and (3) collect the emissions and route them to a process (i.e., have self-contained controllers). The commenter provides that, if that is the case, then allowing the exemption more broadly does not cause any

harm because the alternative standard would never come into play. In contrast, the commenter states that providing the exemption provides protection against a situation where none of the identified methods will work. They suggest the following proposed regulatory text change for 40 CFR 60.5390b(b) and 60.5394c(b) (struckout language indicates deleted text):

(b) For each pneumatic controller designated facility located at a site ~~in Alaska~~ that does not have access to electrical power, you may comply with either paragraphs (b)(1) and (2) of this section or with paragraph (b)(3) of this section, as an alternative to complying with paragraph (a) of this section.

Response II-7-54: One reason the exemption from the zero-emissions standard was provided for process controllers in Alaska at sites without access to electrical power is that solar panels are less likely to be able to provide the necessary power generation due to the hours of darkness that occur in the fall and winter months owing to Alaska's northern latitudes. The use of solar panels to power process controllers is one of the options the EPA found was technically feasible and cost-effective at most sites; however, the EPA does not believe solar panels could feasibly be used to power process controllers at most sites in Alaska. The EPA also recognized that most sites in Alaska have access to electrical power and will be able to comply with the zero-emissions standards through the use of electrical controllers or grid-powered compressed air systems and did not expect the exemption to be widely available to sites there.

The NSPS and EG are required by the CAA to be based on the BSER. In the BSER analysis conducted for the December 2022 Supplemental Proposal and in the refreshed analysis conducted for the final rule, zero emissions from process controllers was shown to be technically achievable and cost-effective at all model plant configurations (outside of Alaska) through several available options, including the use of electrical controllers powered by electricity from the grid, solar power systems, and generators. As such, the EPA determined that zero-emissions represents the BSER and is the basis for the requirements of the NSPS and EG. In addition, other zero-emissions process controller options are available that are technically achievable and cost-effective for some sites include, but are not limited to, pneumatic controllers powered by compressed air using electricity from the grid, electric generators, or compressed nitrogen canisters; routing controller emissions to a process; and using self-contained process controllers.

Comment: Commenters (2326-AXPC, 2353-CrownQuest) express that the EPA has not completed a comprehensive analysis of which locations, basins, and portions of basins can timely and adequately obtain line power. The commenter recommends that the EPA exempt sites from the zero-emitting requirements (as it did for Alaska) after requiring a demonstration that line power cannot be obtained or cannot be obtained timely based on technical, safety and economic considerations.

Commenter (2446-IPAA) recommends that EPA allow operators of affected facilities to perform their own cost-effectiveness evaluations specific to their equipment, geographic location, and other unique operational complexities. The commenter mentions that the problem is acknowledged for Alaska-based sites, but the same issues of remoteness can affect almost every basin in which domestic production occurs.

Commenter (2177-Southern Ute Indian Tribe) states all exemptions for facilities located in Alaska should be allowable for any facilities that can demonstrate that the exemption is appropriate.

Response II-7-55: The EPA understands that sites with process controllers may not have access to electrical power. There are several options available to such sites to meet the NSPS and EG. These include, but are not limited to, the use of solar-powered process controllers, the use of electric process controllers powered by a generator, the use of compressed air-driven process controllers powered by a generator, and routing emissions to a process.

As explained above in Response II-7-73, one reason the exemption from the zero-emissions standard was provided for process controllers in Alaska at sites without access to electrical power is that solar panels are less likely to be able to provide the necessary power generation due to the hours of darkness that occur in the fall and winter months owing to Alaska's northern latitudes. The use of solar panels to power process controllers is one of the options the EPA found was technically feasible and cost-effective at most sites; however, the EPA does not believe solar panels could feasibly be used to power process controllers at most sites in Alaska. The EPA also recognized that most sites in Alaska have access to electrical power and will be able to comply with the zero-emissions standards through the use of electrical controllers or grid-powered compressed air systems and did not expect the exemption to be widely available to sites there.

In the BSER analysis conducted for the December 2022 Supplemental Proposal and in the refreshed analysis conducted for the final rule, zero emissions from process controllers was shown to be technically achievable and cost-effective at all model plant configurations (outside of Alaska) through several available options, including the use of electrical controllers powered by electricity from the grid, solar power systems, and generators. As such, the EPA determined that zero-emissions represents the BSER and is the basis for the requirements of the NSPS and EG. As the EPA has already determined through this analysis that there are technically feasible zero-emissions options for all sites with electricity and those without electricity located outside of Alaska, additional analyses performed by others for individual sites is not necessary.

#### ***7.2.11 Intermittent Vent Controllers***

Comment: Commenter (2351-Jonah Energy) states that, in the Technical Support Document (TSD), EPA uses a 0.29 standard cubic feet (scf)/hour (hr) emission factor for a normally functioning intermittent-bleed pneumatic device. The commenter notes that this would suggest that the focus should be on malfunctioning intermittent-bleed pneumatics, rather than all pneumatics since a normally functioning pneumatic device has minimal emissions. As the commenter already conducts monthly LDAR inspections and a minimum of quarterly LDAR inspections at their production facilities, they find and repair the malfunctioning devices within 24 hours if possible and in a much shorter duration than the annual basis that EPA assumes in the 8.8 scf/hr intermittent-bleed emission factor. The commenter suggests that a more robust LDAR program to identify and repair malfunctioning intermittent-bleed pneumatics should be proposed, rather than including the malfunctioning pneumatic devices in the intermittent-bleed emission factor.

The commenter (2351-Jonah Energy) notes that the EPA acknowledges that a robust monitoring and repair program can achieve the same benefits of reduced emissions for intermittent-bleed pneumatics. The commenter states that they have such a robust monitoring and repair program in place. They assert that the EPA should not penalize companies that have such a robust monitoring and repair program currently implemented by mandating an expensive facility upgrade program that would result in minimal emission reductions. The commenter recommends EPA allow for the option to implement a robust monitoring and repair program to capture malfunctioning pneumatic devices that would serve the same purpose.

The commenter (2351-Jonah Energy) provides that through their United Nations Environment Programme's (UNEP) Oil and Gas Methane Partnership 2.0 (OGMP 2.0) measurement campaign, they have collected 72 separate measurement readings from intermittent-bleed pneumatic device vents at 24 of our production facility locations in the Jonah Field during various times of the year. The average from their measurement readings resulted in a 0.55 set/hr/device. [They provide a chart of their measurement data in a chart in their comment letter.] They noted that their 0.55 set/hr/device is consistent with EPA's 0.29 scf/hr emission factor for a normally functioning intermittent-bleed device and provides further support that EPA should not base their cost-benefit analysis on an 8.8 scf/hr intermittent-bleed emission factor that includes malfunctioning devices as that will skew the benefit to cost ratio. [Comment letter includes a Figure showing the average scf/hr/device for 24 intermittent-bleed pneumatic device vents]

Commenter (2252-PAW) notes that the EPA uses a 0.29 scf/hr emission factor for a normally functioning intermittent-bleed pneumatic device. The commenter states that this would suggest that the focus should be on malfunctioning intermittent-bleed pneumatics, rather than all pneumatics, since a normally functioning pneumatic device has minimal emissions. The commenter recommends that the EPA allow for a LDAR program to identify and repair malfunctioning intermittent-bleed pneumatics, rather than including the malfunctioning pneumatic devices in the intermittent-bleed emission factor.

Commenter (2446-IPAA) states that the EPA utilizes inaccurate data to justify “zero-emitting” BSER for pneumatic controllers. The commenter reports that concurrent with the EPA’s NSPS OOOOb and EG OOOOc proposal, EPA proposed revisions to the current Greenhouse Gas Reporting Program (GHGRP) requirements. The commenter states that the GHGRP data used as a basis for EPA’s NSPS OOOOb and EG OOOOc proposal overstates methane emissions for intermittent controllers by as much as 96 percent. To demonstrate how GHG emissions from intermittent-bleed pneumatic devices are significantly overstated by the current GHGRP subpart W rules versus proposed GHGRP revisions, the commenter includes a Table in their comment letter [pdf pages 26 through 28 of their comment letter] that presents comparisons of methane emissions associated with intermittent-bleed pneumatic devices as determined by the current GHGRP "Eq. W-1" versus the proposed GHGRP "Eq. W-1A" versus the proposed GHGRP "Eq. W-1B" using member's operations and actual voluntary LDAR program results. Based on the comparisons, current GHGRP requirements ("Eq. W-1") overstate methane emissions associated with intermittent-bleed pneumatic devices by approximately 35 percent compared to proposed GHGRP alternative 1 ("Eq. W-1A") and by approximately 96 percent compared to proposed GHGRP alternative 2 ("Eq. W-1B"). If the same 1 percent leak rate was assumed AND quarterly LDAR surveys were performed, such that all leak durations were 2,190 hours vs. the default of

8,760 hours, the commenter reports that the GHG emissions would be overstated by approximately 97.4 percent when using proposed GHGRP alternative 2 ("Eq. W-1B").

Response II-7-56: The EPA agrees that a more robust LDAR program applied nationwide would likely reduce emissions from intermittent vent process controllers. However, the NSPS and EG are required by the CAA to reflect the degree of emission limitation achievable through the application of the best system emission reduction that has been adequately demonstrated, considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. While a more robust LDAR program is one method to reduce emissions nationwide from process controllers, such a program would not impact continuous bleed controllers and would not reduce emissions from intermittent vent controllers to the degree that other options available are capable of achieving. The EPA found in its BSER analysis that there are several zero-emissions process controller options available for which the costs are reasonable, considering the emissions reductions that would be achieved and other impacts resulting from the use of those options. For this reason, the EPA found that zero-emissions process controllers is the BSER, rather than other options resulting in lesser degrees of emission reductions, including enhanced LDAR program for intermittent vent controllers. We note that in our refreshed BSER analysis conducted for the final rule, the most up-to-date emissions factors were used, which included those used in the final GHGRP revisions.

Comment: Commenter (2180-PA DEP) supports EPA's proposal to require all new and existing pneumatic controllers, including intermittent vent pneumatic controllers, to produce zero methane and VOC emissions.

Response II-7-57: This comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2383-BH) states that should the EPA choose to adopt the zero-emission threshold, they recommend that pneumatic controllers/positioners be allowed as long as they do not bleed continuously at steady state, and bleed to atmosphere be allowed only if the valve is in motion.

Commenter (2211-Lambda Energy) reports that they utilize intermittent bleed devices that rarely activate as the existing marginal wells produce very little gas and result in very limited activation and emissions. According to the commenter, such devices on most of its sites sit idle, emitting very little to no methane.

Response II-7-58: The EPA notes that intermittent vent process controllers are those that are designed to not continuously bleed natural gas and to emit natural gas only when actuated. When properly operating, the emissions from these controllers can be relatively low; however, when malfunctioning, the emissions from this controller type can be very high and may emit continuously rather than just when actuated. This high emissions rate when malfunctioning combined with a large percentage of malfunctions in this controller type results in high overall emissions from intermittent vent process controllers. The final NSPS and EG will largely

eliminate these emissions by requiring process controllers to have zero emissions at most sites (*i.e.*, those outside of Alaska and those in Alaska with access to electrical power).

### ***7.2.12 Technology-Neutral Standard***

Comment: Commenter (2399-GPA) recommends that instead of requiring the use of specific types of equipment, EPA use a technology-neutral standard. As they provided in their November 2021 comments (and included as Exhibit A at page 26 of their comment letter), they state that they do not support the requirement for zero-emission controllers for all applications and believe that EPA overlooked significant technical difficulties and costs in the use of solar powered electrical controllers. The commenter requests that EPA consider a technology-neutral standard, which would include the use of generators at sites without access to electricity and allow for certain exemptions for reliability and safety concerns.

Response II-7-59: For process controllers both the December 2022 Supplemental Proposal and the final rule are technology-neutral. The standards require that each process controller affected facility (outside of Alaska and in Alaska at sites with access to electrical power) have zero emissions of methane and VOC to the atmosphere. Owners/operators are free to choose the technology or method to use to comply with this requirement. Owners/operators are not required to use solar-powered process controllers and may use generators or other methods to attain zero emissions from process controllers.

### ***7.2.13 Other***

Comment: Commenters (2252-PAW, 2351-Jonah Energy) state that the EPA is proposing emission reduction mandates for gas-actuated pneumatic controllers using emission factor-based emissions estimates, rather than measurement-based emissions estimates. The commenters assert that the EPA should allow the option for an alternative periodic screening approach. One such approach could be if site-level emissions measurements show methane emissions to be less than a minimum detection threshold that operators should not be required to spend extensive capital to implement emission controls that would have minimal impact on reducing emissions.

Response II-7-60: The EPA acknowledges that emission factors were used in its analysis of the emissions and emission reduction potential of control options for process controllers. These emission factors are based on the averages of controller emissions observed in the field from various studies. For intermittent vent controllers, which represent the majority of process controller types, emission factors are especially important to use when considering the total emissions that occur from process controllers, as they incorporate the emissions that result from both properly functioning and malfunctioning equipment. Such malfunctions may not occur all the time and may not be observed on a particular day during a site assessment but may later be present and would be unaccounted for. As malfunctioning intermittent controllers have been found to be quite prevalent<sup>18</sup>, accounting for their existence is an important component of overall process controller emissions. To achieve site-specific emissions reductions as well as emission

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<sup>18</sup> Greenhouse Gas Reporting Rule: Technical Support for Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule; Proposed Rule— Petroleum and Natural Gas Systems, hereafter referred to as the “subpart W TSD,” available in Docket Id. No. EPA–HQ–OAR–2023–0234.



reductions on a nationwide scale, it is important to use an approach that accounts for all emissions, and the use of emissions accomplishes that for process controllers.

Comment: Commenter (2351-Jonah Energy) requests that EPA consider a tiered approach to compliance with pneumatic controller emissions as follows:

- Control gas-actuated pneumatic controller vents that regulate dump or process flow control to an emission control device if the operator does not have reasonable access to line power.
- Permit emergency pneumatic controllers, which operate only in the case of an upset condition, such as remote well shut-in controllers, to continue to operate as gas motive with LOAR inspections in accordance with these proposed rules to demonstrate they are not venting.
- Replace gas-motive pneumatic controllers with zero vent controllers where an operator has reasonable access to power.

As the rule is currently proposed, the commenter (2351-Jonah Energy) states that the EPA is mandating operators spend capital on emission sources that may not be large contributors to site-level emissions, especially for small production facility locations. Companies that are part of OGMP 2.0 are learning where capital expenditures can best be utilized to reduce emissions. The commenter provides that, if EPA mandates that capital be spent on small production facilities with very few normally functioning natural gas-actuated controllers, that capital is not available to be spent elsewhere where it may be better served and have a larger impact in reducing emissions.

Response II-7-61: In the BSER analyses conducted by the EPA for the December 2022 Supplemental Proposal and the final rule, the EPA evaluated the emissions and emissions control options available to owners/operators for process controllers. In these analyses, the EPA found that there are technically feasible zero-emissions options available at sites both with access to electrical power and those without access to electrical power that have costs the Agency regards as reasonable, considering the emissions reductions that would be achieved. Therefore, process controllers with zero emissions was determined to be the BSER and the basis for the NSPS and EG. The EPA notes that emergency process controllers that only function in an upset condition would meet the definition of “emergency shutdown device,” and these devices are not subject to the process controller requirements.

## **7.3 NSPS OOOOb and EG OOOOc BSER Analysis/Emissions/Costs**

### ***7.3.1 Emissions/Emission Factors***

Comment: Several commenters assert that the basis for emissions used in pneumatic controller BSER analyses are overstated. Examples of specific comments are provided in the following paragraphs.

Commenter (2248-NDPC) takes the position that the pneumatic controller emission factors in 40 CFR 98 overestimated the emissions from this source category and that the EPA’s focus on

regulating these sources is unwarranted. The commenter contends that voluntary LDAR programs can assure that maintenance of pneumatic controllers is performed promptly.

Commenter (2173-Northeast Natural Energy) states EPA acknowledges that historical GHG inventories, including those from the 2021 GHGI for 2019 emissions, are overstated. The commenter specifically points out that emissions are overstated by approximately 35 percent at least and over 90 percent at most for intermittent-bleed pneumatic devices, which represent most of the pneumatic devices in operation within the petroleum and natural gas system segments today. As such, according to the commenter, a 5 percent difference in emission reduction by allowing the use of existing or new control devices is hardly a "significant increase" as stated in the *Federal Register* at page 74765 and should absolutely be an acceptable alternative BSER.

Commenter (2252-PAW) reports that their members have experience with collecting measurement data, including many non-zero measurement readings from intermittent-bleed pneumatic device vents at production facilities during different times of the year. The commenter states that the average measurement readings from its members resulted in a 0.55 standard cubic feet (scf)/hour (hr)/device, which is consistent with the EPA's 0.29 scf/hr emission factor for a normally functioning intermittent-bleed device and provides support that EPA should not base their cost-benefit analysis on an 8.8 scf/hr intermittent-bleed emission factor that includes malfunctioning devices.

Commenter (2403-PAO) notes that EPA's use of emission factors and methodologies overestimates emissions from these devices which has led to excessive requirements.

Commenter (2446-IPAA) notes that the EPA's analysis of BSER for pneumatic controllers and pneumatic pumps relies on information that overstates the emissions from these sources. It is particularly an issue for intermittent pneumatic controllers that are widely used at existing oil and natural gas production operations and therefore, according to the commenter, badly skews the cost-effectiveness analysis. The commenter also states that the GHGRP emissions factors are flawed and being reviewed by EPA for revision; and that even the revisions are at issue. The commenter reports that their use produces a faulty analysis. Although many Subpart W reporters currently perform voluntary (and mandated) NSPS OOOOa compliant LDAR surveys utilizing OGI cameras, in-line with the proposed GHGRP revisions, and can identify properly operating devices versus malfunctioning devices, the commenter states that the current rules do not allow the data to be used. As such, the commenter asserts that the GHGRP data significantly overstates GHG emissions from intermittent-bleed pneumatic devices.

Commenter (2428-API) notes that within the TSD, EPA includes a scenario for monitoring intermittent vent controllers. Based on EPA's assumptions, this kind of program can achieve 96.7 percent reductions in emissions (based on emission factors) for an overall site-level control efficiency of 65 percent based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, the commenter anticipates that this control efficiency could be even higher. In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. The commenter notes that this suggests that

EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

Response II-7-62: We note that in our refreshed BSER analysis conducted for the final rule, the most up-to-date emissions factors were used, which included those used in the final GHGRP revisions. However, the final GHGRP does not include an emission factor for intermittent vent controllers, and instead requires that sites calculate emissions for each site based on site-specific measurements. Therefore, to estimate emissions from intermittent vents, the EPA used an average emission factor of intermittent vent emissions from a recent study that includes both properly functioning and malfunctioning intermittent vent process controllers.<sup>19</sup> As these emission factors have been updated recently and are based on data from field studies of emissions from process controllers, these emission factors are the best data available to estimate nationwide emissions from process controllers. The EPA does not anticipate that the use of these emission factors significantly overstate or understate emissions.

The EPA agrees that a more robust LDAR program applied nationwide would likely reduce emissions from intermittent vent process controllers. However, the NSPS and EG are required by the CAA to reflect the degree of emission limitation achievable through the application of the best system emission reduction that has been adequately demonstrated, considering the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements. While a more robust LDAR program is one method to reduce emissions nationwide from process controllers, such a program would not impact continuous bleed controllers and would not reduce emissions from intermittent vent controllers to the degree that other options available are capable of achieving. The EPA found in its BSER analysis that there are several zero-emissions process controller options available for which the costs are reasonable, considering the emissions reductions that would be achieved and other impacts resulting from the use of those options. For this reason, the EPA found that zero-emissions process controllers is the BSER, rather than other options resulting in lesser degrees of emission reductions, including enhanced LDAR program for intermittent vent controllers.

Comment: Commenter (2383-BH) recommends against adopting the proposed requirements in NSPS OOOOb and EG OOOOc that operators design and operate each pneumatic controller affected facility with zero methane and VOC emissions to the atmosphere. The commenter expresses that there are valid safety and production considerations associated with such a requirement that justify a non-zero emission threshold for these devices, and recommends EPA adopt an emission rate for natural gas-driven pneumatic controllers of less than or equal to 6 scfh, as included in the 2016 NSPS OOOOa rule. According to the commenter, such a threshold would serve as a backstop to operator performance. The commenter points out that other safety backup and devices on older facilities may only actuate a few times/day or even per week. The default 8,760 hours are used when calculating their emissions, which the commenter states leads to an over-estimation of emissions.

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<sup>19</sup> Luck, B., D. Zimmerle, T. Vaughn, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, L. Williams, and D. Allen. 2019. "Multi-Day Measurements of Pneumatic Controller Emissions Reveal Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations."

Response II-7-63: In the BSER analyses conducted by the EPA for the December 2022 Supplemental Proposal and the final rule, the EPA evaluated the emissions and emissions control options available to owners/operators for process controllers. In these analyses, the EPA found that there are technically feasible zero-emissions options available at sites both with access to electrical power and those without access to electrical power that have costs the Agency regards as reasonable, considering the emissions reductions that would be achieved. Considering comments on the zero-emissions standards included in the 2021 proposal and information available to the EPA regarding process controllers, the EPA determined that it was appropriate to not include emergency shutdown devices, which perform important safety functions, in the process controller affected facility definition. The EPA notes that these devices, which actuate infrequently, are also not included in the analyses of emissions resulting from the operation of natural gas-driven process controllers. Therefore, the EPA expects that the commenter's concerns regarding safety and emissions from these infrequently actuating devices have been addressed and accounted for in the final rule.

### ***7.3.2 Model Facilities***

Comment: Commenter (2399-GPA) recommends that EPA gather additional information to create a representative gathering and boosting compressor station model plant. The commenter provides the following for consideration:

- Gathering and boosting compressor stations typically have many more than 20 controllers and require air compressors larger than 20 horsepower, as EPA assumed in the “Large Model Plant” for production sites.
- The total capital cost for installing an air compressor for new controllers with grid power is between \$250,000 and \$1,000,000, depending upon the compressor station's size, layout, and the number of devices.
- EPA appears to assume that any existing source switching from gas-driven devices to electric devices can still use the same valves. However, in most cases, new valves would be required due to actuator setup changes.

Response II-7-64: In the refreshed BSER analysis conducted for the final rule, the EPA included a large model plant to address gathering and boosting stations that would not be represented by 20 controllers. We characterized this model plant as a “large midstream” plant with 100 controllers. In the analysis, we found that there are zero emissions process controller options at this model plant size with costs that the EPA has determined are reasonable, considering the associated emissions reductions. The EPA notes that if an air compression system is used, the process controller requirements do not require other equipment at the site to be powered by that system, and this may reduce the size of the system the commenter has stated is needed. In addition, in our BSER analysis, we assumed that existing natural gas-driven pneumatic devices could be used if the owner/operator switches to a compressed air system, since the devices are capable of using any type of compressed air or gas. We also note that in the past, switching to electric controllers required a switch in the control valve associated with the retrofitted controller. However, the technology of electric process controllers has advanced, and most electric controllers and actuators can be connected to existing valves.

Comment: Commenter (2428-API) identifies errors and assumptions in the December 2022 proposal's TSD model plant analysis:

- While a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30 percent annual cost difference.<sup>20</sup>
- EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at \$32,000). Larger-sized systems should be evaluated.
- For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
- The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Commenter's member experience suggests this is closer to 3 to 4 times equipment costs.
- EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported.<sup>21</sup>
- The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

Response II-7-65: In consideration of these comments, we have addressed several of these items in the refreshed BSER analysis. This includes matching the annualization for solar panels to a 10-year lifespan, adding a compressor retrofit model plant assuming that a 20 hp system would be needed, and assuming that a compressor lifespan is 6 years. For the increased costs for installation of equipment at an existing site, the EPA included an

### **7.3.3 Costs**

#### **7.3.3.1 Proposed Pneumatic Controller Standard is Cost-Effective and Feasible**

Comment: Commenter (2433-EDF et al) expresses that the EPA's proposed pneumatic controller standard is cost-effective and feasible. The commenter provides that the EPA updated its cost analysis and continues to find that the zero-emitting controller standard is cost-effective overall. Specifically, it finds in the production segment that grid-connected, solar, and compressed air controllers are cost-effective at small sites (\$81/ton, \$119/ton, and \$984/ton, respectively), medium sites (\$48/ton, \$84/ton, and \$531/ton, respectively), and large sites (\$31/ton, \$65/ton, and \$297/ton, respectively) (using a multipollutant approach), all of which are reasonable and below EPA's \$1,970/ton benchmark for this proposal and the \$2,185/ton benchmark used in

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<sup>20</sup> See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.

<sup>21</sup> See Attachment C in EPA-HQ-OAR-2021-0317-0808.

previous rules. They add that the EPA also finds cost-effectiveness for these technologies across model plants in the transmission and storage segments (except for instrument air at some sites). The commenter describes and supports changes EPA made in its updated analyses.

The commenter (2433-EDF et al) believes that the EPA's updated cost analysis is more robust, and they support its cost-effectiveness determination. The commenter states that the EPA incorporated a number of changes to its cost analysis that are warranted by the underlying record evidence. They believe that it is now properly accounting for annual maintenance costs of both natural gas pneumatic systems and electric/instrument air systems in accordance with the Carbon Limits cost model. For natural gas pneumatic systems, it averages maintenance costs of systems with wet and dry gas. For zero-emitting systems, it accounts for annual maintenance of electric controllers, periodic replacement of solar panels and batteries (for solar-powered sites), and the cost of grid electricity (for grid-powered sites).

Commenter (2433-EDF et al) provides that the EPA also adjusted its cost analysis to distinguish new sites from existing sites in a few ways. First, capital costs for new sites will now include net costs to "represent the difference in the capital cost between the pneumatic controller system not driven by natural gas and the natural gas-driven controllers that would be used in the absence of a zero-emissions requirement." Additionally, EPA updated the emission factors so that they are now consistent with recent proposed GHGRP updates.

Though the commenter states that the EPA's analysis has improved significantly, the commenter (2433-EDF et al) still believes that the EPA likely still overestimates the costs, and underestimates the cost-effectiveness, of zero-emitting pneumatic controllers. First, EPA's small, medium, and large model plants do not reflect the actual average size of transmission and storage facilities (based on the average size reported in EPA's GHGI). The commenter states that the EPA did not address this issue in response to comments and continues to inaccurately size its model plants. According to the commenter, this has likely resulted in EPA underestimating cost-effectiveness, as zero-bleed conversion becomes more cost-effective as the size of the plant increases. The commenter recommends that EPA increase the size of its model plants to accurately reflect average plant sizes.

Second, the commenter (2433-EDF et al) suggests that the EPA inappropriately increased installation cost estimates for electric controller systems in its updated analysis. As described in a new 2023 memo from Carbon Limits,<sup>22</sup> EPA's new, higher installation costs may be appropriate for certain remote sites (such as those in Northern Alberta) where travel costs can be fairly high. EPA's estimates therefore now represent the upper range of installation costs that are applicable only to a small number of sites. But in proposing a national standard, EPA should consider average installation costs, or costs that will be representative of sites nationally. Those average installation costs are presented in the Carbon Limits tool and are much lower than EPA's current estimates, meaning EPA is likely overestimating installation costs and underestimating cost-effectiveness. The commenter recommends that EPA use Carbon Limits' average installation cost estimates.

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<sup>22</sup> Carbon Limits, 2023 Memo, *supra* note 257.

The commenter (2433-EDF et al) also states EPA has demonstrated solar is cost-effective and feasible at remote locations without electricity. The commenter notes that the EPA soundly addressed purported limitations associated with solar systems – including geographic conditions, temperature, battery capacity, snow cover and particle accumulation on panels, and large-scale applicability. It noted that Canadian provinces with colder temperatures and significant snowfall have successfully implemented non-emitting controller regulations that include solar as a primary remote compliance option; that it received comments by vendors that reported successful installation and operation of emission controller systems in a variety of climate conditions and one who commented on the installation of solar-driven instrument air systems in several states, including Wyoming and Colorado; that technology providers interviewed for the Carbon Limits report have solar-powered controllers installed at well sites in remote and cold locations in places like Northern Alberta and British Columbia without major reliability issues; that one provider interviewed by Carbon Limits installed solar systems at over 400 well-sites in Alberta and British Columbia; that solar panels are placed vertically to eliminate snow cover during winter months; and that solar technology has improved significantly over the years.

The commenter (2433-EDF et al) suggests that the EPA can add to the record in support of solar feasibility by noting that (1) the Carbon Limits report, which EPA uses in its updated cost analysis, accounts for low temperatures and reduced battery capacity;<sup>23</sup> (2) that an independent report by Analysis Group considers region-specific solar capacity factors at all sites, including extra-large sites, and finds cost-effectiveness across all regions;<sup>24</sup> (3) that the same report accounts for particle accumulation on solar panels,<sup>25</sup> (4) and that the Carbon Limits model, which EPA relies on, has a default assumption to oversize the solar panel by 50 percent for electric controllers and 30 percent for solar-powered instrument air systems, so that a loss of generation due to factors such as particle accumulation will not degrade system performance.<sup>26</sup>

The commenter (2433-EDF et al) adds that the EPA has also demonstrated that the zero-emission standard is cost-effective and feasible at large and small sites. The commenter explains that the EPA performed an analysis of the cost effectiveness of the use of electric controllers and solar-powered controllers at sites with a single controller. For sites with only one high-bleed controller, the cost effectiveness was estimated to be \$379 and \$437 per ton of methane reduced for electric and solar-powered controllers, respectively. For a site with one intermittent vent controller, the cost effectiveness values were estimated as \$913 per ton for electric controllers, and \$1,053 per ton for solar-powered controllers. For a site with one low-bleed controller, the cost effectiveness values were \$1,181 per ton for electric controllers and \$1,363 per ton for solar-powered controllers. The commenter reports that these all fall below EPA's cost-effectiveness benchmark. The commenter suggests that the EPA can further bolster its analysis by noting that

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<sup>23</sup> See Carbon Limits, 2021 Report 5–6 (included in 2022 Joint Environmental Comments, *supra* note 1, as Attachment N).

<sup>24</sup> Analysis Group, Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power Zero-Emission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations, at 17–18, 46 (May 6, 2022) [hereinafter Analysis Group Report] (included as Attachment M).

<sup>25</sup> Analysis Group, Methane Reduction Technology Electricity and Abatement Costs: Summary Presentation for EPA (May 10, 2022) [hereinafter Analysis Group Presentation] (included as Attachment N).

<sup>26</sup> Carbon Limits, 2021 Report, *supra* note 268, at Appendix A: List of assumptions, Table A. 1: Quantitative assumptions for the model.

the 2021 Carbon Limits report found cost-effectiveness for solar-powered instrument air systems at smaller sites.

The commenter (2433-EDF et al) also notes that there is an independent report by Analysis Group assessing the costs to operate zero-emission technologies that further demonstrates the cost-effectiveness of EPA's pneumatic controller proposal, with specific emphasis on the cost-effectiveness of these technologies by region, including the Midwest, Mid-Atlantic, South, Rocky Mountains, and Alaska. The report concludes that, after incorporating electricity and net maintenance costs, all technologies considered (grid-connected, solar, and instrument air) are cost-effective at small, medium, and large plants in all regions, even when gas savings are not considered. Some highlights of the report provided by the commenter include:

- *Solar Controller Analysis Considers Regional Conditions, Particle Accumulation, and Large Solar Sites:* The report's solar controller evaluation accounts for a potential decrease in solar/storage output in colder climates and due to particle accumulation on panels. The model assumes ten days of energy storage at a maximum depth discharge of 80 percent. Additionally, solar levelized costs were adjusted regionally based on differences in solar capacity factors. Even after incorporating these variances into the model, the report finds that the installation of zero-emitting pneumatic controllers is cost-effective in each region, including Alaska, countering claims that facilities in colder and cloud-covered states cannot feasibly install solar-driven controllers and that particle accumulation makes solar infeasible. The report also considers oversizing the solar array and battery storage to the extent necessary to ensure sufficient generation to power controllers. Based on these assumptions, in combination with its use of independent regional levelized costs of solar and storage, the report finds that large facilities can use solar controller systems cost-effectively.<sup>27</sup>
- *Consideration of Extra-Large Sites:* The report supplements EPA's analysis by considering extra-large sites. It considers sites with electricity demand reaching 2,000 kW by modeling an extra-large plant size of 200 controllers for production and transmission and storage sites and finds that nearly all technologies would be cost effective. This counters certain industry commenters' claims that zero-emitting technologies are not cost-effective at plants that are larger than EPA's model plants or at sites requiring 2,000 kW of electricity.<sup>28</sup>
- *Adjusted Capital Expenditures:* The report's grid-powered, solar, and instrument air controller analyses all include adjusted capital expenditures for equipment, prepared independently of EPA's analysis.<sup>29</sup>
- *Maintenance Costs:* Unlike EPA's original analysis (but like the analysis for its supplemental proposal), the analyses for all three technologies incorporate net maintenance costs, which result in savings associated with replacing gas-driven controllers with zero-emitting controllers.<sup>30</sup>
- *Costs of Service Extension:* The report further supplements EPA's costs analysis by considering the costs for locations that do not have electricity supply on-site but are

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<sup>27</sup> See Analysis Group Report.

<sup>28</sup> Id.

<sup>29</sup> Id.

<sup>30</sup> Id.



located close enough to the local electric distribution system to consider developing a line extension from the closest spot on the grid. The report finds that, in most situations, the cost of constructing a distribution line when an operator is 0.5 miles away from access plus electricity use results in cost-effective methane abatement. While cost-effectiveness may decrease with more distance from the grid, this conclusion rebuts certain industry commenters' claims that the cost to obtain grid access is prohibitive.<sup>31</sup>

- *Electricity Costs*: The report's grid-powered and instrument air analyses consider electricity costs by region. The report estimates the cost of delivered electricity as the average of state prices for electricity to ultimate customers and finds that installation of zero-emitting pneumatic controllers would be cost-effective in all regions.<sup>32</sup>

Response II-7-66: The EPA has refreshed its BSER analysis for process controllers to incorporate updated data. This includes the following changes to the controller model plants.

- Two new "midstream" model plants were added to represent gathering and boosting stations. The small midstream model plant contains 20 pneumatic controllers, and the large midstream model plant contains 100 pneumatic controllers.
- The three transmission and storage model plants used in the supplemental analysis were replaced by a small transmission and storage model plant (30 pneumatic controllers) and a large transmission and storage model plant (50 pneumatic controllers).
- The breakdown of controllers at the new small production model plants was changed to reflect a higher percentage of intermittent vent controllers. For new sources, the supplemental analysis assumed 2 low bleed and 2 intermittent vent controllers. This was changed to 1 low bleed and 3 intermittent.

The EPA found in the refreshed BSER analysis that solar-powered electric process controllers have costs that are reasonable considering the emissions reductions that would be achieved at all model plants studied.

#### 7.3.3.2 EPA Has Underestimated the Costs of its Proposal

Comment: Several commenters submitted comments indicating that they believed that the EPA had underestimated the costs of its proposal. Examples of some of the comments received are provided in the following paragraphs.

Commenter (2227-WEA) believes that the EPA has significantly underestimated the cost and difficulty of retrofitting facilities to comply with the regulation. The commenter reports that their member estimates from actual retrofit projects range to as high as \$250,000 per facility for large facilities with many controllers, which is a price point far outside the range described in EPA's publication. According to the commenter, while these costs may be lower for lower-producing

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<sup>31</sup> See Amer. Petroleum Inst., Comments on EPA's Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review 7–8 (Jan. 31, 2022), <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-0808> [hereinafter 2022 API Comments].

<sup>32</sup> See Analysis Group Report.

facilities, the fact that EPA estimated the top end for the range for large facilities to be only \$96,000 signals there is a flaw in the calculation for it to be that far off actual project execution.

Commenter (2305-Williams) states for sites without reliable electricity, upgrading utility power to the facility to accommodate zero-emitting or zero-venting pneumatic controllers could cost over a million dollars, or require installation of natural gas-fired generators at a cost of \$600,000 to \$750,000. Scoping of the appropriate generator size will require an owner and operator to power more than the air compressors at these facilities since the generator will generate power for other equipment such as replacing gas pneumatic pumps. The commenter reports that these natural gas generators will range from 600 - 1114 bhp with a minimum delivery time of 15 months (separate and apart from the delivery time for an air compressor).

Commenter (2283-Endeavor Energy) states EPA also drastically underestimates the costs of its proposed pneumatic equipment. The commenter estimates that it would cost about \$85,500 per well site to convert pneumatic equipment to instrument air.

Commenter (1609-Qnergy) states typical installations are medium facilities with 16 controllers and above and about 2 scfm. At \$4/MMBtu of natural gas, a 9 scfm site is highly profitable, where the operator enjoys about \$13,000 of net profit each year (about \$135 profit from each ton of abated methane). At 6 scfm and \$2/MMBtu the operator breaks even while offsetting the whole site entire emissions.

Response II-7-67: For the final rule, the EPA refreshed the BSER cost analysis to include updated cost information, updated emission factors, and additional model plant sizes. For this analysis, the EPA reviewed the available information regarding the costs of the control technologies and strategies evaluated and incorporated updated information where it was available. The changes included updates to the costs of some components of solar-powered systems. However, these changes were modest and were reductions in the costs of the equipment, and there no instances where the EPA found that costs had previously been underestimated. The EPA notes that for sites with many controllers beyond the sizes of the model plants evaluated, the costs could be higher than estimated. At such sites though, the emissions reductions would also be higher than estimated. The results of the updated BSER analysis show that there are several zero-emissions options for process controllers that have reasonable costs, considering the emissions reductions that would be achieved.

Comment: Several commenters specifically provided comments on EPA's December 2022 supplemental proposal pneumatic controller BSER cost-effectiveness analyses. Examples of some of the specific comments are provided in the following paragraphs.

Commenter (2399-GPA) states EPA's cost models only considered production and transmission facilities. They do not include gathering and boosting facilities. The commenter states that gathering and boosting facilities have much larger system requirements due to the larger number of controllers and the need for more powerful air compressors. Assuming that gathering and boosting facilities have roughly equivalent system requirements as production facilities dramatically underestimates costs. The commenter provides that owners and operators of gathering and boosting facilities may spend \$500,000 to \$1,000,000 for instrument air systems at

sites with available grid power. For sites that require onsite power generation, the cost could readily increase by an additional \$400,000 to \$1,000,000. The commenter states its facilities and upstream production facilities are simply not comparable for purposes of analyzing the cost-effectiveness of the proposed regulations. The commenter provides the following additional operational and/or cost differences between production sites and gathering and boosting operations included in the Carbon Limits report:

- The pneumatic devices used for the three model production sites are substantially smaller than most gathering and boosting compressor stations. These smaller scale cost metrics will not linearly scale up with larger facilities where new instrument air header and piping, additional pipe supports, or an extended pipe rack may be necessary.
- The installation costs for a header to the pneumatic controllers, in Table 5 of the Carbon Limits report, is for a new installation. Retrofits often require the existing methane pipe header to remain in place as a source of fuel gas to on-site equipment, such as compressors, fired heaters, combustors/ thermal oxidizers, or flares. A new parallel air header needs to be run to all instruments, adding significant costs depending upon the location, site layout, available space, and the need for additional pipe supports. Put simply, the installation costs at a well site are not useful in determining the cost-effectiveness of retrofitting gathering and boosting operations.
- The stated installation costs in the Carbon Limits report are much lower than what GPA Midstream member companies typically see. It does not appear that wire and miscellaneous electrical material were accounted for. Further, the installation labor time per each device does not appear for the time to pull wire to each device. This may not be significant at small production sites with only a handful of devices, but for larger equipment, this will involve significantly more time and higher costs to install.
- In the midstream industry, typical total project costs are three to four times the major equipment cost for brownfield facilities. The Carbon Limits report improperly assumed only two times major equipment cost. It is not clear if the report properly accounted for hydrovacating underground inside the fence line, work permits, additional safety and personal protective equipment costs, and other issues that add to overall brownfields project cost.
- For greenfield sites, total project costs are typically two to three times major equipment costs. For instance, one of our member company's New Mexico central gathering facilities has 34 shutdown valves, 70 other pneumatic devices, and 34 diaphragm pumps. The site will install 150 horsepower of air compression (two 75 horsepower flooded screw compressors) for this relatively large operation. The commenter's vendor quotes indicate that the skid price for these compressors, the dryer, wet/dry air receiver, and off skid star air receiver is approximately \$250,000. See Exhibit E. Total project cost is anticipated to be approximately \$1,050,000, which includes roughly \$175,000 to route sufficient utility power to a location if that is required. This is an installation factor of 3.5 times the major equipment cost (not including utility power costs).<sup>33</sup> Yet, the Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation.

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<sup>33</sup> A second member looked back at projects over the past 2 1/2 years and found a similar installation factor for their projects.

- Table 9 of the Carbon Limits report provides a cost comparison for the Sample C Site, the larger productions site. For the site with no electricity and using solar power, the report calculates \$2,200 per device with the controller accounting for \$2,000 of that cost. This means that the Carbon Limits authors assumed that it would cost only \$200 per device for installing the device, installing a new panel, purchasing wire and miscellaneous electrical materials, and pulling wire from the panel to the device. In the experience of our member companies, these costs are underestimated by one to two orders of magnitude, depending upon the site's size and complexity.
- At a retrofit site with no electricity, the Carbon Limits report assumed approximately \$2,900 to install solar power and electric controllers. As the Carbon Limits report assumes the controllers are \$2,000 each, this leaves only \$900 to retrofit each valve with an electric controller, install a new panel, purchase wire and miscellaneous electrical equipment, and pull wire from the panel to the device. The owner or operator may also have to excavate and remove buried lines. Further, retrofitting goes significantly slower than for new installations. This means that Carbon Limits' installation cost assumptions are underestimated by at least one to two orders of magnitude depending upon site size and complexity.
- In retrofitting a site with no electricity using solar powered electric controllers and new control valves, the Carbon Limits report estimates a cost of \$4,700 per device with each controller costing \$2,000 and each control valve costing \$2,500. This leaves a mere \$200 per device to install the controller, valve, new panel, purchase wire and miscellaneous electrical equipment, and pull the wire. The Carbon Limits report evidently did not consider the need to shut in, isolate, and blow-down the process to be able to physically install the new valves into the piping, then remove isolation valves, purge, and pressure up before putting the equipment back into service.
- In retrofitting a site with electricity, using the electric controller option and existing valves, the Carbon Limits report estimates a cost of \$2,700 per device with the controllers costing \$2,000 each. This would leave only \$700 for installing each controller – a process that goes far slower than installation on a new source and may require excavating buried lines.
- Finally, the Carbon Limits report estimated that retrofitting a site with access to electricity using electronic controllers and new control valves would cost approximately \$4,600 per device with each controller costing \$2,000 and each control valve costing \$2,500. This leaves only \$100 per device to install each controller and valve, involving shutting in, isolating, and blowing down the process, removing isolation valves, purging the system, and then re-pressuring before putting the equipment back into service. This is simply not credible and demonstrates that the Carbon Limits report's authors lack the understanding of midstream operations necessary to apply its findings to the midstream industry.

The commenter (2446-IPAA) notes that the Carbon Limits report assumes that, for a new site with electricity, the electronic controller option is only \$1,950 per device. The commenter suggests that it is not clear why the controller cost is less than that for a site with no access to electricity, but even assuming the lowest potential controller cost - \$1,500 – it is implausible that a company can install the device for only \$450 each. Given the labor and additional materials

described above, the commenter believes that the \$450 in installation costs is severely underestimated.

For a new site with electricity, the commenter (2446-IPAA) provides that the Carbon Limits report also assumes that grid instrumentation will cost only \$50,000 for a 20-horsepower air compressor, leaving approximately \$31,000 for installation. According to the commenter, this is two to three times lower than typical installation costs, which including building a foundation, setting the instrument air skid and air receiver, grounding the skid, running a new air heading to 22 devices, and running power to the new air compressor skid.

Commenter (2294-OOGA) disagrees that the BSER is reasonable from a cost-effectiveness perspective. The commenter reports that it will require existing sources to retrofit every pneumatic controller. Some facilities may even require complete reengineering and design to comply with these standards. The commenter contends that such compliance measures will likely be cost prohibitive, particularly for small business and operators of low production wells. There are also a multitude of technical limitations, such as low pressure, that make each proposed compliance option infeasible.

Commenter (2428-API) states that total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed \$1,000,000. Upon the commenter's review of the December 2022 Supplemental Proposal TSD, the commenter asserts that they found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the technical feasibility of making these retrofits as summarized below [greater detail is provided in the commenter's letter]:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller;
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis;
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis;
- In a case study published by National Renewable Energy Laboratory (NREL), solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions;
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities:
  - Additional Land Requirement for Solar Panel Installation including acquisition costs.
  - Site Preparation - For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
  - Solar panel maintenance and cleaning particulate accumulation,
  - Permitting<sup>34</sup>, insurance and inclusion of battery boxes to house batteries, and
  - Retrofits often require the existing methane pipe headers to remain in place as a

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<sup>34</sup> <https://www.solarpermitfees.org/SoCalPVFeeReport.pdf>.

source of fuel gas for on-site equipment (compressors, fired heaters, combustors/thermal oxidizers, flares, etc.) and a new parallel air header needs to be run to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

Response II-7-68: The EPA considered these comments and made some revisions to the BSER analysis. These include adding two new “midstream” model plants to represent gathering and boosting stations. The small midstream model plant contains 20 pneumatic controllers, and the large midstream model plant contains 100 pneumatic controllers. The three transmission and storage model plants used in the supplemental analysis were also replaced by a small transmission and storage model plant (30 pneumatic controllers) and a large transmission and storage model plant (50 pneumatic controllers). The results of the analysis for these new and revised model plants show while the costs for sites with more controllers are higher, the emissions reductions are also higher. The EPA determined that the costs are reasonable, even for these large sites, considering the emissions reductions achieved.

Regarding comments related to installation costs, the EPA has not revised our general estimation methodology. The Carbon Limits reports<sup>35</sup> assume that equipment installation costs are 50% for new sites and 100% for existing sites. The additional costs for existing facilities take into account the existing infrastructure that may need to be changed, such as the parallel air headers remarked on by commenters. This is in line with or even greater than the assumptions in the EPA Cost Control Manual,<sup>36</sup> which the EPA has relied on for estimating emissions control costs for many other rulemakings.

Regarding the emission factor for low-bleed process controllers, the EPA notes that the emission factors are based on measurement studies of process controllers in the field. The emission factor of 6.8 standard cubic feet per hour (scfh) shows that these controllers are not, in fact, operating as they should be with less than 6.0 scfh.

#### 7.3.3.3 Connection to the Electrical Grid

Comment: Commenter (2227-WEA) states there are significant development, operational, and socio-economic considerations for the widespread use of electricity for oil and natural gas operations. Expanding electrical infrastructure in many areas in the west can be slower and more costly than other areas in the U.S. This is particularly true given the lack of existing infrastructure, severe geographic challenges such as mountains and canyons, requirements for enhanced extensive environmental studies, added environmental restrictions, lengthy land development challenges, extreme weather conditions, and other trials that are magnified in some areas. The commenter explains that there are regions of the U.S. where the proposed regulations are likely to result in more significant economic impacts than those across much of the rest of the lower 48 states. There are areas where oil and natural gas products are required to be sold at

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<sup>35</sup> Carbon Limits. (2016) Zero emission technologies for pneumatic controllers in the USA - Applicability and cost effectiveness. and (2021) Zero emission technologies for pneumatic controllers in the USA – Updated applicability and cost effectiveness.

<sup>36</sup> EPA Air Pollution Control Cost Manual. Sixth Edition. January 2002. EPA/452/B-02-001.

discounted rates for reasons such as the characteristics of the product and unique requirements to process the products. Some regions are severely lacking in pipeline transportation and must use more expensive long-distance transportation modes such as trucking. The commenter provides that the economic challenges that accompany requirements to retrofit operations for the use of electricity in place of pneumatic energy are significant.

Response II-7-69: While the use of electricity supplied by the grid is one method available at some sites to power electric process controllers or to power a compressed air system for pneumatic controllers, the use of grid energy is not the only option available to owner/operators for compliance with the process controller standards. The use of solar-powered electric process controllers, pneumatic process controllers using compressed air systems powered by generators, and routing process controller emissions to a process are examples of other compliance methods available to meet the zero-emissions process controller standard. The EPA found through its BSER analysis that there are cost-effective methods of compliance available for all site types, including remote sites without access to electrical power.

#### 7.3.3.4 Solar

Comment: Commenter (2433-EDF et al) states that the EPA has found the installation of solar-powered systems to be cost-effective, and its determination that these systems are feasible at remote sites without electricity is supported by strong record evidence.

Response II-7-70: This comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

#### 7.3.3.5 Electric Controllers

Comment: Commenter (2399-GPA) states electrically actuated controllers require the installation of a complex automated control system, which would require offsite monitoring using a Supervisory Control and Data Acquisition (SCADA) system—which is an additional cost that EPA does not appear to have included in its estimates.

Response II-7-71: While electrically actuated controllers can be operated by a SCADA system, this is not required as they also have local controls on each actuator. Therefore, this cost was not included in our analyses.

Commenter (2166-OH DNR) calculated various implementation costs for a typical Ohio oil and gas operator. Using \$20,593 for the capital investment of an electric controller system and the current market price of \$3.00 per thousand cubic feet (Mcf) of gas, a well would need to produce 6,864 Mcf of gas to pay back the cost of an electric controller system. The commenter notes that a marginal well producing less than 250 Mcf of gas a year would take nearly three decades (27 years) to recoup the investment for a controller system if all revenue from the well was put towards paying for the system. The commenter adds that it would take longer since a well operator incurs costs to operate a well and pay to transport natural gas. At an average market price of \$1.71 per Mcf and \$41.96 for a barrel of oil in 2020, the owner's estimated total gross

revenue for 2020 would have been \$10,761.14. The commenter states that this would mean that two years of total gross revenue would be needed to retrofit one well to an electric controller system.

Response II-7-72: EPA developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells. It is also possible that a less expensive compliance method could be chosen. The EPA notes that for existing sources, States may take remaining useful life and other factors into account when formulating their state plans for implementation of the EG, consistent with the requirements in 40 CFR subpart Ba.

Comment: Commenter (2399-GPA) notes that, although electrically actuated controllers can be installed in certain limited circumstances, they are more expensive with fewer options available on the market. The commenter contends that mandating their use would further drive-up prices with manufacturers being unlikely to catch up to increasing demand until after the December 2022 supplemental proposed rule compliance date.

Response II-7-73: The final rule does not mandate the use of electrically actuated controllers. While owner/operators may use electric process controllers to comply with the zero-emissions standard, other options include the use of pneumatic process controllers driven by a compressed air system or nitrogen canisters and routing emissions to a process.

#### 7.3.3.6 Instrument/Compressed Air Systems

Comment: Commenter (2227-WEA) states that for smaller facilities that have lower production, installing and operating instrument air systems could easily exceed the value of the recoverable production from the wells associated with those facilities, forcing those operators to shut in production.

Response II-7-74: EPA developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells. Information regarding the implementation of a state rule in Colorado with process controller requirements show that less than 7 percent of sites there shut in production.<sup>37</sup> In addition, States

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<sup>37</sup> EPA-HQ-OAR-2021-0317-3847.



may take remaining useful life and other factors into account when formulating their state plans for implementation of the EG, consistent with the requirements of 40 CFR part 60 subpart Ba.

#### 7.3.3.7 Self Contained/Route to Process

Comment: Commenter (2360-Devon Energy) encourages EPA to consider the benefit and cost-effectiveness of routing existing pneumatic controllers to a process, sales line, or to a combustion device (where one already exists) instead of emitting directly to the atmosphere. The commenter provides that Colorado and New Mexico are actively working to create progressive regulatory frameworks to reduce methane emissions, consider “routed pneumatic controllers” to be “non-emitting controllers,” which facilitates an effective pathway to reduce methane emissions from existing pneumatic controllers. The commenter contends that allowing for the routing of existing pneumatic controllers to a combustion device will significantly enhance the ability for oil and gas operators to effectively reduce the emissions from gas-driven pneumatic controllers within the prescribed compliance timeframe and provide a reasonable level of flexibility to achieve the non-emitting standard without potentially requiring an additional emission source in the form of a generator where electricity is not readily available.

Response II-7-75: The EPA acknowledges that it may be cost-effective for owner/operators to route process controller emissions to a process or sales line, and this is an option available for meeting the zero-emissions standard for process controllers. The EPA considered the costs and emissions reductions associated with routing emissions to a combustion device but found that this method of emissions reduction did not represent the BSER. As methods to attain zero emissions are available, in use at some sites, and have costs and other impacts that are reasonable considering the emissions reductions that would be achieved, the EPA determined that zero emissions represents the BSER for process controllers.

#### 7.3.3.8 Nitrogen-Powered Controllers

Comment: Commenter (1581-Kathairos) states nitrogen systems provide an economical methane elimination solution for pneumatics, even for small, low vent wellsites:

- Costs are scaled to the size of the affected facility. The cost of the system is directly commensurate with the amount of methane that otherwise would have been vented. Small, low-vent wellsites are fitted with small (265 liter (L)) tanks and consume small amounts of nitrogen, resulting in total costs as low as \$2,100 per year.
- No up-front capital required. Tank lease and nitrogen costs paid on monthly basis.
- Oil and gas producers retain the fuel gas that otherwise would have been vented, which is conserved for future sale.
- The exact costs of the nitrogen system for a range of different vent rates provided in Appendix A (Abatement Cost by Vent Rate) of their comment letter.

Response II-7-76: Although the EPA has not performed an analysis of the costs associated with the use of nitrogen systems, the EPA acknowledges that the use of these systems is a technically feasible option available to owners/operators for compliance with the process controller standards.

### ***7.3.4 BSER Based on Regional Considerations***

Comment: Commenter (2353-CrownQuest) states that the EPA's rule is a national rule, not a state-by-state or region-by-region rule. The EPA changing their modeling to three generic sites does not address the massive variance in the type of facilities and oil and gas producing sites. Oil and gas wells' output declines over time. New shale wells can decrease by 80 percent in the first year, and waterfloods can drop as low as 2 percent. The natural makeup of the hydrocarbons in the reservoir can vary wildly from oil sands already exposed to the surface with little associated gas to retrograde gas reservoirs that are primarily gas and a little liquid. The EPA does this with its nationwide approach to zero-emitting pneumatic valves.

The commenter (2353-CrownQuest) points out that pneumatic valves are intermittent and only emit after they are deactivated. The volume of emissions will depend on how often each valve activates. So, a facility making 10 barrels per day will emit less than a facility that makes 100 barrels per day if both have the same number of pneumatic valves. The EPA averages all pneumatic valves (over a million of them) and applies the same standard and expected emission reduction to all facilities. The commenter states that this assumption is not correct. Lower-volume facilities will emit less than higher-volume facilities, and those emissions will drop as the natural decline of oil and gas drops over time.

The commenter (2353-CrownQuest) requests that the EPA reset and take a regional look at developing BSER for each region rather than lumping all 50 states and thousands of different reservoirs in the same national regulation. An example where EPA used an industry BSER is installing instrument air systems on newly constructed facilities. According to the commenter, this example is a practice already becoming common in the industry that is attainable with little impact on design, construction, or operation. There are exceptions, however, where it doesn't make sense to do this, such as shallow wildcat-type wells. The commenter explains that the implementation of installing instrument air applications on newly constructed facilities is a good one. This system and design benefit the operator and environment in emissions reduction. This kind of application is a viable BSER.

Response II-7-77: In the BSER analysis, the EPA used emission factors to estimate emissions from process controllers. These emission factors are averages of emissions that were measured at many sites and incorporate process controllers that actuate frequently and those that actuate infrequently, along with those that are operating properly and those that are malfunctioning. For intermittent vent process controllers, which make up the majority of process controllers currently in use, malfunctioning process controllers account for most of the emissions. These malfunctioning controllers can emit natural gas continuously and can be located at any site, such that even low-output well sites can have high emissions from process controllers. With this consideration, it is important to control emissions from process controllers at all sites.

For all model plants evaluated, the EPA found zero-emissions process controller options that are cost effective. One method of attaining zero-emissions from process controllers is the use of instrument air systems. However, there are other methods available, such as the use of solar-powered electric controllers, that owner/operators may choose to use if an instrument air system is not a good choice for a particular site.

## 7.4 Low Production/Small Sites

Comment: Commenter (2433-EDF et al) agrees with EPA's reasoning set out in the December 2022 proposal preamble<sup>38</sup> and concurs that operators of small sites can cost-effectively implement the standard and does not recommend that the EPA permit an exemption for smaller sites.

Response II-7-78: This comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Several commenters (2227-WEA, 2238-SOOGA, 2428-API, 2403-PAO) request that the EPA consider allowing the use of low-bleed or intermittent bleed pneumatic controllers at low production/small sites. Specific comments are provided in the following paragraphs.

Commenter (2238-SOOGA) urges U.S. EPA to consider an alternative BSER, including but not limited to allow for low and properly functioning intermittent-bleed controllers in compliance with NSPS OOOOa, based on site-specific cost-effectiveness evaluations that account for the facility's equipment, geographic location, and other unique operational conditions. The commenter recommends that properly functioning pneumatic controllers be assessed through AVO inspections.

Commenter (2428-API) suggests that at existing locations without access to electrical power there be an option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, the commenter asserts that the EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Commenter (2227-WEA) notes that older facilities that currently have very little throughput, and therefore very little emissions from pneumatics due to infrequent activation, installing a gas driven or diesel driven air compressor could increase GHG emissions from the facility, or at the very least result in a very small reduction in emissions. For those facilities, in the EG OOOOc context, the commenter recommends that low-bleed or intermittent bleed controllers be required.

Commenter (2403-PAO) requests EPA establish a separate standard for pneumatics at existing locations, especially low producing, marginal wells. The commenter states that the proposal allows sites in Alaska to use low bleed continuous pneumatic controllers where onsite power is not available. They explain that converting high bleed devices to low bleed devices is a commercially available option at a fraction of the cost of replacing the entire device.

Commenters (2252-PAW, 2326-AXPC, 2351-Jonah Energy) recommend that the EPA allow an alternative option for controlling VOC and methane emissions for small production facility locations with less than some designated count of natural gas-actuated controllers, to allow for

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<sup>38</sup> See 87 Fed. Reg. at 74769.

routing those controllers to an existing process or control device, similar to what is currently proposed for locations with three or fewer natural gas-actuated pneumatic pumps.

Response II-7-79: In the BSER analysis, the EPA used emission factors to estimate emissions from process controllers. These emission factors are averages of emissions that were measured at many sites and incorporate process controllers that actuate frequently and those that actuate infrequently, along with those that are operating properly and those that are malfunctioning. For intermittent vent process controllers, which make up the majority of process controllers currently in use, malfunctioning process controllers account for most of the emissions. These malfunctioning controllers can emit natural gas continuously and can be located at any site, such that even low-output well sites or sites with few process controllers can have high emissions from process controllers. With this consideration, it is important to control emissions from process controllers at all sites.

The EPA considered the costs and emissions reductions associated several options for emissions control. As methods to attain zero emissions are available, in use at some sites, and have costs and other impacts that are reasonable considering the emissions reductions that would be achieved, the EPA determined that zero emissions represents the BSER for process controllers. The EPA found in its BSER analysis zero-emissions compliance methods were cost-effective at all model plant site types evaluated.

Comment: Commenter (2254-PBPA) states many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The commenter notes that the complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production. The commenter requests that the EPA exempt low producing wells from the pneumatic controller requirements.

Commenter (2428-API) requests that the EPA allow additional flexibility for existing sources to allow states to preserve the remaining useful life of facilities. They suggest that EPA provide 1) adequate time and phase-in to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) focus on the conversion to non-emitting controllers at facilities with the largest number of controllers. To effectively do this, the commenter recommends that the allow the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers and monitored periodically for proper functioning at the frequency specified in 40 CFR 60.5397c.

Response II-7-80: Based on the timing of the steps in the EG implementation process, the EPA believes existing facilities will be able to procure the necessary process controller equipment by the time compliance is required. Under CAA section 111(d), each state must submit a plan to the EPA that establishes standards of performance for each designated facility. For purposes of EG OOOOc, the EPA is finalizing a requirement that each state adopt and submit these plans within 24 months after publication of the final EG OOOOc. The EPA is also finalizing a timeline for compliance with the requirements included in the state plans of no later than 36 months from the deadline for state plan submittals. The combined time allotted for final compliance then could be up to 60 months, or 5 years from the publication date of EG OOOOc. This period of time should

provide all operators with ample opportunity to determine a compliance strategy and procure and install the necessary equipment. In addition, 40 CFR 60.24a(e) also applies to EG OOOOc, which establishes that when applying a standard of performance to a particular source, a state may consider factors, such as the remaining useful life and other factors with respect to specific sources. If there are demonstrable circumstances that make the OOOOc final compliance time unreasonable or unattainable, states have the flexibility to consider these factors consistent with 40 CFR subpart Ba, and propose to incorporate alternative dates in their state plans.

## 7.5 Applicability and Compliance Date Considerations

Comment: Commenter (2433-EDF et al) contends that supply chain considerations do not alter the reasonableness of EPA's proposal. First, operators have generally been able to transition their fleets within EPA's proposed schedule. EQT, the largest natural gas producer in the U.S., retrofit all its sites to eliminate natural gas-driven controllers in less than one and one-half years.<sup>39</sup> And Diamondback anticipates it will have replaced "nearly all" of its controllers with zero-emitting devices within four years.<sup>40</sup> Second, EPA set forth strong record evidence regarding the availability of solar-driven systems, which is an important option for remote sites. For example, EPA the commenter states that the EPA noted one provider that has installed solar systems at over 400 well-sites in Alberta and British Columbia, and cited comments from several providers of solar-driven systems. Critically, as EPA explains in this proposal, operators have thus far not provided evidence that there is inadequate supply of solar-driven technology.

In addition to EPA's own analysis, the commenter (2433-EDF et al) reports that a recent report by Datu Research further underscores that the supply chain for the production of zero-emitting technologies is not a barrier for industry-wide adoption of zero-emission controllers and that, on the contrary, the supply chain is strong enough to support implementation of EPA's proposed standards.<sup>41</sup> Datu's report identifies forty providers of zero-emitting controllers and surveyed nine.<sup>42</sup> Its interviews with these providers demonstrate that suppliers are well equipped to meet anticipated demand within EPA's proposed regulatory timeline. Datu also re-surveyed providers after the Methane Emissions Reduction Program (MERP) passage, and providers indicated that MERP, in addition to EPA's regulations, will further catalyze the production and distribution of zero-emitting devices. Key findings:

- A well-established, capable set of zero-emission controller providers is in place. The report identified 40 providers of zero-emitting pneumatic controller equipment, several of which manufacture long-established technologies used across industries. Many of the 40 listed are mature companies that have served the oil and gas industry for decades, with a

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<sup>39</sup> EQT Eliminates Nearly 9,000 Natural Gas-Powered Pneumatic Devices, PRNewswire (Jan. 4, 2023) <https://www.prnewswire.com/news-releases/eqt-eliminates-nearly-9-000-natural-gas-powered-pneumatic-devices-301713418.html>.

<sup>40</sup> Diamondback Energy, 2021 Corporate Sustainability Report 8 (2021), <https://www.diamondbackenergy.com/static-files/faf5ab25-5ab5-4404-8c04-c7bd387ae418>.

<sup>41</sup> Datu Research, Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand? (Jan. 2023) (Attachment P).

<sup>42</sup> Id. at 5, 9.

median 43 years in operation.<sup>43</sup> These companies also serve on average five different industries, indicating providers have a wide demand base.<sup>44</sup>

- Zero-emission controller components are mature and designed to integrate into existing systems. Components like electric actuators and instrument air compressors have been in use for decades, and providers of these components emphasize that integrating them into existing natural gas-driven systems is fairly simple.<sup>45</sup>
- Technology providers already see strong demand for retrofits and new installs. In their interviews, providers noted that their oil and gas clients are already choosing alternatives to natural gas-driven controllers not only because of anticipated regulations, but also because of the economic benefits – including preserving saleable product, maintenance cost savings, and less downtime – and the safety benefits associated with reducing flammable product in the workplace.<sup>46</sup> Companies are also preferring electronic systems because of their intelligent connectivity capabilities that keep on-the-ground information flowing continuously.<sup>47</sup> Five companies interviewed indicated that 60-90 percent of their sales were for retrofits.<sup>48</sup>
- Technology providers have strategies for meeting current supply chain challenges. Though procurement delays have been a reality for some suppliers, they have employed strategies like paying higher prices, storing extra quantities of supplies, bringing in more procurement personnel, going to different distributors, spot-buying on the open market, and finding contract manufacturing sites. Larger companies reported facing fewer hurdles.<sup>49</sup>
- Regulatory certainty steadies demand. Even considering supply chain concerns, providers have confidence in their ability to expand production capacity so long as regulatory certainty helps keep demand steady over multiple years.<sup>50</sup>
- MERP is already increasing demand for zero-emitting alternatives and will likely bring innovation and new technology providers into the U.S. market. Providers reported that MERP has resulted in an increase in purchase orders and that they anticipate MERP will accelerate the transition to zero-emitting technologies.<sup>51</sup>

Commenters (2202-TXOGA, 2428-API) suggest that a 60-day compliance deadline for new/modified sources is unrealistic due to supply chain concerns, personnel shortages, and inflation. The commenters propose at least a one-year timeframe for NSPS OOOOb compliance.

Commenter (2326-AXPC) proposes that EPA extend the initial compliance deadline for pneumatic controllers, pneumatic pumps, and storage vessels at least one year for those affected facilities that became NSPS OOOOb affected facilities between the “new” trigger date and the date the final rule is published in the *Federal Register*. Alternatively, the commenter states that, if EPA is unwilling to provide extended initial compliance deadlines as requested, they request

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<sup>43</sup> Id. at 5.

<sup>44</sup> Id.

<sup>45</sup> Id. at 8.

<sup>46</sup> Id. at 9.

<sup>47</sup> Id. at 14.

<sup>48</sup> Id. at 9.

<sup>49</sup> Id. at 3.

<sup>50</sup> Id. at 11–12.

<sup>51</sup> Id. at 12–13.

that EPA provide extensions where good cause exists, as it did under the recently promulgated Uintah and Ouray Indian Reservation FIP for oil and natural gas sources.

Commenter (2399-GPA) requests that the EPA allow more than one year from publication of a final rule for retrofitting “new” sources subject to NSPS OOOOb to comply with the zero emission controller requirements. The commenter believes that, if EPA finalizes its proposed zero emission controller requirements, supply chain and labor issues will only become worse as the standards are applied nationwide for both new and existing sources.

For “modification” or “reconstruction” facilities, commenter (2305-Williams) reports that they currently experience lead times for the non-natural gas driven pneumatic controllers, generators, and air compressors ranging from 12-24 months. The commenter notes that there is no indication that this will improve in the near future and can be expected to worsen as owners and operators across the country will increase demand in response to the December 2022 supplemental proposal. This leaves even the most responsible owner or operator without the ability to comply within 60 days. The commenter recommends a compliance deadline of 24 months from the publication date of Final Rule.

Commenter (2483-INGAA) requests that EPA give operators 24 months from the publication of the final rule to come into compliance with the zero-emissions requirement for pneumatic controller affected facilities. They also suggest that the applicability date for all of NSPS OOOOb be the date of the publication of the December 2022 supplemental proposed rule: December 6, 2022. The commenter contends that not changing the applicability date for pneumatic controller affected facilities under NSPS OOOOb to December 6, 2022, would violate the due process rights of owners and operators since they had no notice that they would be required to replace all the valves at a facility if a modification occurred and have lost valuable time to accomplish such a task. The commenter states that this lack of notice provides further support for providing 24 months from the publication of the final rule for individual, existing pneumatic controllers, at an affected facility that is modified or reconstructed, to come into compliance with zero-emissions requirements.

Commenter (2258-MSC) notes that, due to severe supply chain shortages and disruptions, generators and other equipment and parts necessary for zero-emission systems can take up to three months or longer for delivery. These supply chain challenges may be exacerbated by this rulemaking, as facilities across the country move to come into compliance. The commenter requests that the EPA establish a reasonable compliance timeframe and allow for a phase-in period for procurement and installation of the systems and equipment necessary (including labor necessary for installation).

Commenter (2279-SBA) recommends that EPA give the state and small businesses flexibility to phase in requirements based on market conditions.

Response II-7-81: Based on these comments and supplemental information submitted by one commenter (API) with updated information to reflect current market conditions, it appears that some equipment may not be available to new facilities or those that have started up or were modified or reconstructed since December 6, 2022, to enable them to install zero-emitting

controllers within 60 days of the publication of the final NSPS.<sup>52</sup> According to this information, some of the operators surveyed report that they are experiencing delays in the availability of process controllers, electrical transformers, generator skids, and compressor skids of up to 12 months. We also considered the information provided by one commenter (EDF) that suggested that extended timeframes would not be warranted, but some equipment providers would need to ramp up production, and some components may not be widely available within 60 days of the publication of the final rule. Considering that the equipment types discussed in the provided information from these commenters are essential to the institution of zero-emitting controllers at a site and the estimated timeframes for the availability of equipment, the EPA is providing a compliance extension of one year for the zero-emissions process controller requirements.

Until the date of compliance of the zero-emissions requirements for process controllers, owner/operators must be in compliance with the requirements for sites in Alaska that do not have access to electrical power. The requirements for such sites are that low-bleed controllers and intermittent vent controllers be used, and that owner/operators perform monitoring of intermittent vent controllers to ensure they do not vent during idle periods. As the current NSPS OOOOa requires these types of controllers to be used, owners/operators of these new and recently modified or reconstructed sites would already be using these types of process controllers if they have not installed zero-emitting process controllers and will only need to begin periodically monitoring natural gas-driven intermittent vent controllers. Therefore, the EPA expects no sites to have any problems complying with these interim requirements within 60 days of publication of the final rule.

Comment: Commenter (2248-NDPC) suggests that, if EPA determines that non-emitting pneumatic controllers should be required under EG OOOOc, it allow for a phase-in period of at least ten (10) years. The commenter explains that factors such as the availability of equipment, personnel capabilities, and location-specific electrification options make it impossible to replace all the emitting pneumatics at sites in any less time.

Commenters (2202-TXOGA, 2428-API) assert that a 3-year compliance deadline will not consider many expected obstacles, such as: supply chain concerns, personnel shortages, and inflation. The commenters propose a five-year timeframe for EG OOOOc compliance.

Commenter (2279-SBA) emphasizes that, because controllers are crucial to oil and natural gas production operations, EPA should provide flexibility in this requirement for those circumstances in which small entities cannot obtain and/or retrofit zero-emitting controllers. They specifically encourage the EPA to phase in any requirement for existing sources. After the phase-in period, they suggest that EPA allow states to grant extensions to small entities that can show a good faith effort to procure non-emitting controllers at a reasonable price.

In the supplemental proposal, the commenter (2279-SBA) notes that the EPA includes a way for state plans to provide some relief for existing sources, through consideration of remaining useful life and other factors (RULOF) in setting emissions standards less stringent than EPA's emission guidelines. EPA provides an example of a state using the RULOF provisions for pneumatic

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<sup>52</sup> API. Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule.



controllers. However, the commenter contends that this flexibility is limited. It requires the state regulatory authority to make findings for a specific facility or class of facilities and identify the facilities in the state plan submitted to EPA. The commenter asserts that this is much earlier in the process than many small businesses will be ready to engage with their state regulators. It also does not give the state and small businesses flexibility to phase in requirements based on market conditions. The commenter recommends that the EPA include these flexibilities directly in the emission guidelines.

Response II-7-82: Based on the timing of the steps in the EG implementation process, the EPA believes existing facilities will be able to procure the necessary process controller equipment by the time compliance is required. Under CAA section 111(d), each state must submit a plan to the EPA that establishes standards of performance for each designated facility. For purposes of EG OOOOc, the EPA is finalizing a requirement that each state adopt and submit these plans within 24 months after publication of the final EG OOOOc. The EPA is also finalizing a timeline for compliance with the requirements included in the state plans of 36 months from the deadline for state plan submittals. The combined time allotted for compliance then is 60 months, or 5 years from the publication date of EG OOOOc. This period of time should provide all operators with ample opportunity to determine a compliance strategy and procure and install the necessary equipment. In addition, information submitted by another commenter on the implementation of a state rule in Colorado, which has similar process controller requirements to those included in the EG, show that both small operators and large operators have been able to comply with the process controller requirements on schedule.<sup>53</sup> Therefore, the EPA has no information to suggest that owner/operators of small operations or large operations will have trouble meeting the EG OOOOc compliance timeline for process controllers.

Comment: Commenter (2483-INGAA) states the “commenced construction date” for applying the definition of commenced construction to pneumatic controllers can be ambiguous under 40 CFR 60.2. The commenter explains that pneumatic controllers are often added or replaced during larger capital projects such as facility expansion or reliability projects. The commenter proposes that for the purposes of pneumatic controller affected facilities installed with capital projects, the commenced construction date be based on the commencement of construction for the overall capital project.

Response II-7-83: The final rule includes in 40 CFR in §60.5365b(d)(2) a definition of “commenced,” which specifies that “For purposes of paragraphs (d)(2)(i) and (ii), ‘commenced’ means that an owner or operator has undertaken a continuous program of natural gas-driven process controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven process controller replacement.” In this context, the appropriate commencement date is an identifiable day upon which the process controller replacement program starts. If there is no such delineation of timeframe for the process controller replacement portion of a larger project, the commencement date of the whole project would be the appropriate commencement date.

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<sup>53</sup> EPA-HQ-OAR-2021-0317-3847.

## 7.6 Miscellaneous Regulatory Text Corrections/Clarifications

Comment: Commenter (2177-Southern Ute Indian Tribe) suggests that EPA recheck citation references. Specifically, they note that 40 CFR 60.5410b(f)(2)(v) and 40 CFR 60.5415b(h)(2)(iv) include a reference to a non-existent 40 CFR 60.5490(b). They also noted that 40 CFR 60.5420c(d) is inappropriately inserted into paragraph (c)(14)(x) and should be formatted as its own paragraph.

Response II-7-84: We corrected the references to section 40 CFR 60.5490b to correctly refer to section 40 CFR 60.5390b and revised the formatting of the paragraph formerly numbered as §60.5420c(c)(14)(x) and now numbered as §60.5420c(c)(14)(viii) to correct the missing separation between it and paragraph §60.5420c(d).

Comment: Commenter (2428-API) EPA includes references to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER], but it is unclear whether it is based on the November 2021 preamble or the December 2022 proposal.

Response II-7-85: The applicability date for process controllers under NSPS OOOOb is the date of publication of the December 2022 supplemental proposal, December 6, 2022.

Comment: Commenter (2428-API) suggests that the following additional citation be checked for correct cross referencing: 40 CFR 60.5410b(f)(2)(iv)(B).

Response II-7-86: After review, we have found that the December 2022 Supplemental Proposal paragraph §60.5410b(f)(2)(vi)(B) had an incorrect cross-reference to another paragraph in the proposed rule. For the final rule, we have revised and reorganized the regulatory text of 60.5410b(f)(2) such that paragraph §60.5410b(f)(2)(vi)(B) no longer contains the same content that was included in that paragraph at proposal. We have ensured that this incorrect cross-reference is no longer in any paragraph of the final regulatory text.

## 7.7 Other Regulatory Topics

### 7.7.1 Secondary Emissions

Comment: Commenter (2248-NDPC) believes the secondary emissions created by the proposed requirements to make the pneumatic controllers non-emitting (e.g., from the manufacturing of new equipment and installation of alternative equipment) could be more significant than what the source emits during its useful life.

Response II-7-87: The EPA recognizes that if owners and operators elect to comply with the process controller requirements by installing and operating a generator, there will be secondary emissions generated from the fuel combustion; however, we have estimated the emissions that would be created by generators and found that they are far outweighed by the VOC and methane emissions reduction that would be achieved by using process controllers that are not driven by natural gas. For the December 2022 Supplemental Proposal, while we recognized that a

commenter had provided estimates of these emissions, we did not separately analyze the secondary emissions that would be created if a generator was used to power this equipment.

We have now conducted that analysis and estimate that for a natural gas-fired generator to power this equipment, the secondary criteria pollutant emissions would be 43 lbs/yr CO, 306 lbs/yr NO<sub>2</sub>, 6 lbs/yr PM, and 3 lb/yr PM<sub>2.5</sub> for a 5 HP compressor and 172 lbs/yr CO, 1,222 lbs/yr NO<sub>2</sub>, 26 lbs/yr PM, and 13 lb/yr PM<sub>2.5</sub>, for a 20 HP compressor. The secondary GHG emissions generated as a result of this electricity generation are estimated to be 11,654 lbs/yr CO<sub>2</sub>, 0.2 lbs/yr methane, and 0.02 lb/yr N<sub>2</sub>O for a 5 HP compressor and 46,618 lbs/ yr CO<sub>2</sub>, 0.9 lbs/yr methane, and 0.09 lbs/yr N<sub>2</sub>O for a 20 HP compressor. Considering the global warming potential of these GHGs, the total CO<sub>2</sub>e emissions would be 11,667 lbs/yr CO<sub>2</sub>e from a 5 HP compressor and 46,666 lbs/yr CO<sub>2</sub>e from a 20 HP compressor. With the total CO<sub>2</sub>e emissions from process controllers at a small site estimated to be 303,000 lbs/yr and 7.5 million lbs/yr for a large site, the total CO<sub>2</sub>e reduction from the use of zero emissions process controllers powered by a generator running a compressed air system would be more than 95 percent when compared to the uncontrolled methane emissions from natural gas driven controllers. No other secondary impacts are expected. Considering this information regarding secondary emissions, we continue to find that the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the production and transmission and storage segments of the industry to be the use of controllers that have a methane and VOC emission rate of zero.

### ***7.7.2 Flexibility for Existing Sources***

Comment: Commenter (2220-WDEQ) states re-routing to a process on site is not a practical or economically feasible solution for many existing sources and can result in unanticipated emissions increases due to other consequential compliance issues. This, in turn, according to the commenter, could result in an increased workload for their compliance staff who will already face a significantly increased burden in site visits and reports due to the increased number of affected facilities as a result of the supplemental proposal. The commenter reports that Wyoming already has a robust New Source Review (NSR) permitting program that successfully reduces NO<sub>x</sub> and VOC emissions – and, consequently, methane emissions – from pneumatics. Furthermore, they report that their compliance staff performs comprehensive site evaluations and timely correspondence with operators throughout the state to ensure that compliance issues are identified and addressed in the most efficient and effective manner possible. The commenter requests that EPA provide flexibility through an off-ramp for permitting programs like Wyoming's that already effectively address pneumatics; because their state's program is so effective, the benefits of implementing the proposed NSPS OOOOb and EG OOOOc requirements for pneumatics would be marginal compared to the significant cost to operators and on-site technical infeasibilities associated with the supplemental proposal.

Response II-7-88: The EPA recognizes the possibility that changes made to processes or equipment at a facility may initially create unintentional issues or problems at the site. However, as the NSPS and EG requirements reduce emissions by 100% from all process controller affected facilities, the guaranteed benefits of these long-term emissions reductions outweigh any potential initial issues that might arise as process or equipment modifications are made. In addition, the EPA has determined that zero-emissions from process controller are technically feasible and the

costs of the options available to attain zero-emission are reasonable considering the emissions reductions that would be achieved. Therefore, the EPA found that zero-emissions from process controllers is the BSER, and this is reflected in the NSPS and EG. Therefore, all sites must comply with these requirements.

### ***7.7.3 Streamlining of Recordkeeping and Reporting Requirements***

Comment: Commenters (2177-Southern Ute Indian Tribe, 2399-GPA, 2428-API) request that the EPA not impose recordkeeping requirements for exempt controllers (e.g., pneumatic controllers that are not natural gas-driven). Commenter (2428-API) notes that it appears that it was EPA's intent to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the commenter suggests that the language proposed within NSPS OOOOb per 40 CFR 60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard.

Response II-7-89: After considering these comments, we have determined that it is appropriate in this instance to require identification of the equipment that is included in the affected facility, rather than the equipment that is not part of the affected facility. The process controllers included in the affected facility are those that are subject to the emissions standards, whereas process controllers not included in the affected facility are not subject to the emissions standards in the final rule, and also have no potential to emit methane or VOCs. Therefore, we have revised the recordkeeping requirements to require identification only of controllers that meet the finalized definition of an affected facility, which are those process controllers that are driven by natural gas and that are not ESDs.

### ***7.7.4 VRU Continuous Monitoring***

Comment: Commenter (2333-LongPath) states that, where a VRU is used to route emissions to a process, continuous, quantitative emissions monitoring data is extraordinarily useful to operators for keeping VRU settings at the appropriate levels, and requests that EPA consider incentivizing operators to use continuous monitoring to monitor VRU set points and efficiency, and to make continuous monitoring an allowable solution for monitoring of VRUs.

Response II-7-90: Continuous emissions monitoring may provide owners/operators with useful operations information, and they may choose to use such a system to inform their processes. However, VRUs which route recovered gas and vapor back to the process are not considered to be control devices<sup>54</sup>, and are not subject to performance testing, emissions monitoring, or parameter monitoring requirements. As the EPA's requirements in the NSPS and EG are aimed at achieving the CAA mandate that the best systems of emissions reductions are used and to ensure systems that reduce emissions are performing properly to achieve the intended emissions reductions, devices that may improve operating performance are outside the scope of this action.

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<sup>54</sup> See 78 FR 58241 and Letter from Peter Tsirigotis to Matthew Todd, American Petroleum Institute. September 28, 2012. Docket Item No. EPA-HQ-OAR-2010-0505-4595.

### ***7.7.5 Combine with Pneumatic Pumps***

Comment: Commenter (2294-OOGA) requests that EPA align the requirements for pneumatic controllers with the requirements for pneumatic pumps including, specifically: allowing emissions to be routed to a control device if it is technically infeasible to route to a process; and excluding natural gas pneumatic controllers that operate for less than 90 days per calendar year from the affected facility.

Commenter (2428-API) states EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The commenter requests that the requirements for both pneumatic controllers and pumps be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device.

Response II-7-91: The EPA has considered these comments and streamlined the requirements for process controllers and pumps to include the same technical feasibility and cost assumptions for components that would be common to both types of zero-emitting equipment, such as the costs and feasibility of the use of solar panels, compressed air systems, and generators. The result of this has largely been changes to the assumptions and costs for pumps, as well as changes to the final rule requirements to more closely align with the requirements for process controllers. For both process controllers and pumps, the EPA has determined the technical feasibility of the available emissions control types along with the costs and other factors associated with the control options, and as such, additional site-specific infeasibility determinations are not necessary. In the final rule for both process controllers and pumps, the requirements are technology-neutral. No additional certifications are required for process controllers or pumps complying with the zero-emissions standards. For pumps at a limited subset of sites for which zero-emissions pumps are not required, certifications are only required to verify the lack of certain emissions control equipment present at the site. For controllers, as technically feasible, cost-effective zero-emissions options were found to be available for all sites, the EPA determined that zero-emissions options represent the BSER, and this is reflected in the NSPS and EG. Therefore, control devices achieving less than 100% emissions reductions do not reflect the BSER and are not allowed for process controllers. For pumps, the EPA determined there are technically feasible, cost-effective zero-emissions options available for sites with access to electrical power and for sites without access to electrical power that have three or more natural gas-driven diaphragm pumps. Therefore, control devices achieving less than 100% emissions reductions do not reflect the BSER and are not allowed for pumps at these sites. For sites without access to electrical power that have fewer than three natural gas-driven diaphragm pumps, the EPA determined that the costs associated with the control of emissions from pumps was only reasonable if there was an existing VRU available onsite to enable emissions to be routed to a process or if an existing control device was otherwise already onsite. The EPA determined that the BSER for these sites is to use a VRU already onsite to route emissions to a process or to route emissions to an already onsite control device if a VRU is not present. The NSPS and EG reflect this BSER finding.

The EPA acknowledged in the December 2022 Supplemental Proposal that the focus of the BSER analysis has been on process controllers that are part of the routine operation of oil and natural gas facilities. We noted that we did not have sufficient information to include an exemption or an alternative standard for process controllers associated with temporary equipment, and we requested more information about these situations. The EPA requested information regarding when temporary equipment is used, the function of the controllers during this time, how they are powered, and the typical duration of their usage. The EPA also requested information explaining in detail why the zero-emission solutions that are used for the permanent equipment at the site cannot be also used for this temporary equipment. As the EPA did not receive this information or further explanation, the EPA has insufficient support for an exemption or alternative standard. Therefore, the final rule has not been revised to separately address process controllers on temporary equipment.

### **7.7.6 Backup Systems**

Comment: Commenter (2383-BH) states pneumatic controllers/positioners should be allowed on backup/monitor systems, provided the controllers bleed only when the backup system is engaged (e.g., in the event of a power failure to a primary electric actuator).

Conversely, commenter (2433-EDF et al) states allowing these backup systems would result in a potential loophole that would enable owners or operators to continue to use natural gas-driven controllers in routine situations. In this way, the commenter suggests that the allowance would amount to a broad exemption from the standard, which, as discussed above, is not necessary given the wide array of available technologies – including natural gas-driven controllers – that operators will be able to use to comply. Moreover, they note that the industry’s analysis regarding the need for such systems is flawed. Carbon Limits interviewed several zero-emission controller technology providers and operators using such controllers at their facilities, and none of these companies indicated a need for a natural gas system backup.<sup>55</sup> Furthermore, the commenter states that none of the rules in Colorado, New Mexico, or British Columbia – all of which prohibit venting natural gas-driven controllers at new sites and require significant retrofits of such devices at existing facilities – allow operators to use venting gas-driven controllers as a back-up. Clearly, according to the commenter, such back-up systems are not necessary.

The commenter (2433-EDF et al) also points out that such an exemption would also be extremely difficult to monitor. Operators would need to show the need to use emitting devices arose due to a system failure, which would require confirmation from EPA in each instance and necessitate personnel and continuous monitoring. The commenter believes that, if EPA is unable to monitor the use of these natural gas back-ups, this exemption would swallow the rule, effectively displacing the zero-emission standard that EPA has demonstrated is cost-effective and feasible.

Response II-7-92: The information regarding zero-emission process controller technologies available to the EPA do not suggest that a natural gas-driven back-up system is necessary. For compressed air systems used to power pneumatic process controllers, the systems are designed with two compressors to ensure one is always available in the case of a malfunction of the other.

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<sup>55</sup> Carbon Limits, 2023 Memo, supra note 257.

If the system uses power from the grid, the system could be designed to have an alternate power source, such as a generator, to ensure the compressed air system does not lose power. If electrical process controllers are used, an alternate power source could also be used to ensure the process controllers continue to function, such as a generator or a battery system. Therefore, the use of natural gas-driven process controllers are not necessary to provide an alternative in the case of a power failure.

Comment: Commenter (1609-Qnergy) states that there is no need for backup systems. Operators can use proven cost-effective instrument air packages that have compressor redundancy i.e., if one compressor is malfunctioning the other will still operate. The built-in redundancy eliminates the need for backup systems.

Response II-7-93: The EPA agrees that backup systems are generally not necessary for compressor systems and that the systems are designed with two compressors so that one is always available to operate in the case of a malfunction in the other. This is the type of system included in the EPA's BSER analyses.

### ***7.7.7 Technology to Abate Methane Emissions***

Comment: Commenter (1609-Qnergy) asserts that the industry<sup>56</sup> can adopt a proven technology to abate methane emissions at minimal to no cost. The difference between 'low-cost' to 'no-cost' depends on the value assigned to the saved natural gas. The commenter notes that its position is based on field experience with respect to cost and per unit abatement capacity.

The commenter (1609-Qnergy) expresses pride in being the only company with a low-maintenance commercial power generator based on a linear 'Free Piston' Stirling Engine with no rotating parts, meaning no need for lubrication and maintenance. The commenter explains that the engine is designed to operate on unrefined methane from natural gas fields and biogas. The technology was developed and is manufactured in the U.S. It has already deployed more instrument air packages in the U.S. natural gas sector than any other company and is considered to be the market leader in off-grid solutions in the 1- 12 scfm range. [The commenter provides a map (Figure 2) in their comment letter of their installations across North America.] The commenter supports the EPA's efforts to eliminate methane and VOCs emissions in a cost-effective manner that reflects the significant technological advancements while providing the industry with clarity and consistency.

Commenter (1609-Qnergy) reports that the nationwide impact of using their technology would amount to abating about 1.2 million (M) tpy of methane at a cost of about \$300M per year across the U.S. industry. This result assumes zero value of natural gas. When the value of natural gas is considered, the abatement cost to the industry ranges from about \$190M at \$2 per million British thermal units (MMBtu) of natural gas to a net gain at \$6 per MMBtu with a crossover at \$5 per MMBtu. [The detailed derivation and sources of data are provided in Appendix B (of the commenter's letter)]. The overwhelming conclusion is that the industry can abate methane

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<sup>56</sup> The commenter refers to 'industry' as gas production sites of two wells and above. Small (1 well per site) installations are not included in our current scope of supply and thus we do not have installation data to share with respect to these sites.

through pneumatic controller at a significantly lower cost than published, based on actual experience across the U.S. The commenter notes that their data is based on successful installations across all U.S. climate zones.

The commenter (1609-Qnergy) states in the broader perspective of instrument air, the industry has long passed the pilot stage. The commenter confirms that it has already installed hundreds of their zero-emission units. According to the commenter, this fact alone should remove any remaining doubt with respect to adequate demonstration of the technology, application, and its cost effectiveness. The commenter also reports emission reductions close to 99.6 percent. The commenter goes on and states EPA's values on instrument air system reductions are too conservative.

Response II-7-94: The EPA agrees that the use of generators to power electrical process controllers or to power compressed air systems is a mature technology, and owner/operators may choose to use such technology for compliance with the process controller requirements of the rule. We note that in our refreshed BSER analysis conducted for the final rule, the most up-to-date emissions factors were used, which included those used in the final GHGRP revisions. However, the final GHGRP does not include an emission factor for intermittent vent controllers, and instead requires that sites calculate emissions for each site based on site-specific measurements. Therefore, to estimate emissions from intermittent vents, the EPA used an average emission factor of intermittent vent emissions from a recent study that includes both properly functioning and malfunctioning intermittent vent process controllers.<sup>57</sup> As these emission factors have been updated recently and are based on data from field studies of emissions from process controllers, these emission factors are the best data available to estimate nationwide emissions from process controllers. The EPA does not anticipate that the use of these emission factors significantly overstate or understate process controller emissions.

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<sup>57</sup> Luck, B., D. Zimmerle, T. Vaughn, T. Lauderdale, K. Keen, M. Harrison, A. Marchese, L. Williams, and D. Allen. 2019. "Multi-Day Measurements of Pneumatic Controller Emissions Reveal Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations."



## Chapter 8. Pumps

### 8.1 NSPS OOOOb and EG OOOOc Affected Facility

#### 8.1.1 Proposed Pneumatic Pump Affected Facility Definition

Comment: Commenter (2410-California Office of the Attorney General (CA AG) *et al.*) supports the EPA’s proposed definition of the pneumatic pump affected facility to include the collection of natural gas-driven pneumatic pumps at a site instead of each individual natural gas-driven pump. The commenter also supports the EPA’s proposal to determine that zero-emission pneumatic pumps in all segments—specifically diaphragm and piston pneumatic pumps in the production segment and diaphragm pneumatic pumps in the transmission and storage segment—are the best system of emission reduction (BSER) for new and existing sources.

Response II-8-1: This comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2326-American Exploration and Production Council (AXPC)) requests that the EPA define the pneumatic pump new source performance standards (NSPS) OOOOb affected facility as, “the collection of natural gas-driven diaphragm and piston pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station that emits or has the potential to emit methane or VOC to atmosphere,” and similarly define the emission guidelines (EG) OOOOc designated facility with respect to only methane.

Response II-8-2: The EPA disagrees that adding the phrase “that emits or has the potential to emit methane or VOC to the atmosphere” should be added to the definition of the affected pump facility. As any natural gas-driven pump would have the potential to emit methane and VOC to the atmosphere, this phrase is redundant and could be confusing as to whether the affected facility includes pumps that have emissions routed to a process or control device. The EPA intends that any natural gas-driven pump be included in the affected facility, and therefore, the definition of affected facility was not changed as suggested by the commenter.

#### 8.1.2 Expansion of Affected Facilities and Proposed Control Options

Comment: Commenter (2428-American Petroleum Institute (API)) states that the expansion of affected facilities and proposed control options are unexpected based on the 2021 proposal. The commenter contends that operators have had no way of knowing:

- Piston pumps would be affected facilities under 40 CFR 60.5365b(h).
- The collection of both piston pump and diaphragm pumps would constitute an affected facility under 40 CFR 60.5365b(h).
- The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in 40 CFR 60.5393b.
- Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the commenter asserts that the applicability date for pneumatic pumps under NSPS OOOOb should be the date of promulgation of the December 2022 supplemental proposal.

Response II-8-3: The EPA agrees that the appropriate applicability date for NSPS OOOOb is the date of promulgation of the December 2022 supplemental proposal, and we have revised the applicability date accordingly. This is discussed further in the preamble in section IX.

Comment: Commenter (2428-API) states that while EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or how it is beyond the definition for natural gas diaphragm pump currently provided. The commenter provides the following recommendations on the definition of diaphragm pump (underlined text indicates new text and struck out text indicates deleted text):

*Natural gas-driven diaphragm pump* means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.

Response II-8-4: The EPA acknowledges that the December 2022 Supplemental Proposal did not include a definition for piston pumps; however, rather than revising the definition of diaphragm pumps, we have added a definition for piston pumps. The added definition reads as follows, “*Natural gas-driven piston pump* means a positive displacement pump powered by pressurized natural gas that moves and pressurizes fluid by using one or more reciprocating pistons. A pump in which a fluid is displaced by a piston driven by a diaphragm is considered a piston pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a piston pump.”

### **8.1.3 Emission Threshold Recommendation**

Comment: Commenter (2180-Pennsylvania Department of Environmental Protection) recommends that the EPA replace the practice of installing emissions controls based on the number of pumps at a facility with an emissions threshold that governs the installation of emissions controls. Since 2018, the commenter states that natural gas-fired pneumatic pumps in Pennsylvania have been required to control emissions by 95 percent or greater if the potential or actual emissions from the pumps exceed 200 tons per year (tpy) of methane or 2.7 tpy of VOC.

Response II-8-5: While the EPA agrees that the determination of when to require emissions controls could be made based on the potential or actual emissions from an emissions source, the EPA has not revised the regulatory text for pumps in the final rule to require emissions controls based on an explicit emissions threshold. The use of such a regulatory emissions threshold implies that emissions at that level are high enough to justify emissions control requirements based on the emissions reductions that could be realized and the associated costs and other impacts of the controls. To simplify the applicability determination process for the final rule, we determined the emissions levels that would be necessary to justify emissions control

requirements and the conditions under which those emissions levels would occur. Thus, we determined in our BSER analysis the site conditions for which control of pumps is reasonable based on the emissions reductions that would be achieved and the costs and other impacts associated with emissions controls. This up-front determination simplifies the applicability process by not requiring owners or operators to determine potential or actual emissions and by not requiring an air quality agency to review that information.

#### ***8.1.4 Request for Exemption of Low-Pressure/Low-Emitting Pumps***

Comment: Commenters (2403-Petroleum Alliance of Oklahoma, 2305-Williams Companies, Inc. (Williams)) request that the EPA allow operators an exemption for low pressure, minimal emission pumps (e.g., chemical injection pumps) or provide an option where technical information could be provided to justify why they should be exempt for replacement and/or retrofitting. Additionally, commenter (2305-Williams) notes chemical injection natural gas-driven pneumatic pumps, such as those used to inject methanol, antifreeze, or defoamer, have generally low emissions and low pressure of emissions when they do occur. According to the commenter, this low-pressure scenario would make it difficult to capture and route the emissions back to a process or a flare with current capture technology.

Commenter (2391-Chesapeake Energy Corporation (CEC)) recommends EPA exempt pneumatic piston pumps with emissions below an appropriate emission threshold in mcf of gas vented per calendar year based on the emission factor of 13.3 standard cubic feet (scf)/hour (hr) in the Subpart W Greenhouse Gas Reporting Program (GHGRP) regulations.

Response II-8-6: The EPA has conducted an analysis of emissions control options for pumps, considering the emissions reduction potential of those options, along with the costs and other impacts associated with the emissions controls. We included pumps with low emissions in this analysis, and we determined that control of such pumps is reasonable under certain conditions. These conditions include having access to electrical power at a site, having three or more natural gas-driven diaphragm pumps at a site, and having existing emissions control devices or a vapor recovery unit at a site. Under these conditions, we determined that the costs and other impacts associated with controlling emissions from pumps are reasonable in consideration of the emissions reductions that would be achieved. For instances in which it is technically infeasible to control emissions from pumps at sites without access to electricity and fewer than three natural gas-driven diaphragm pumps, the final rule also retains the provisions included in the December 2022 Supplemental Proposal that allow owners or operators to demonstrate that it is technically infeasible to control emissions from pumps.

#### ***8.1.5 Zero-Emitting Pumps***

Comment: Commenter (2177-Southern Ute Indian Tribe (Southern Ute)) states that 40 CFR 60.5410b(g)(1) requires owners and operators to submit the identification of all your pneumatic pumps that are not powered by natural gas in your initial annual report as required by 40 CFR 60.5420b(b)(10)(i). The commenter recommends pneumatic pumps that are not powered by natural gas be exempt from the rule, and not included in an initial compliance demonstration.

The commenter suggests that operators only be required to maintain records sufficient to determine applicability with the regulations.

Commenter (2227-Western Energy Alliance (WEA)) contends that treating zero-emitting pneumatic pumps as affected facilities will have very little effect on reducing emissions. The commenter explains that zero-emitting pneumatics are an example of industry innovation to solve the problem of methane leaks. By treating them as affected facilities, the commenter states that the EPA is disincentivizing technical innovation and subjecting zero-emitting equipment to unnecessary recordkeeping and reporting. The commenter provides that, if there were to be a malfunction of a zero-emission pneumatic controller or the gas capture system connected to a pump, the malfunction would be found and subsequently repaired through leak detection and repair (LDAR). The commenter asserts that there is no need to include zero-emissions equipment as affected facilities.

Commenter (2326-AXPC) states EPA proposes best system of emission reduction (BSER) that would result in no VOC or methane emissions from pneumatic controllers, pneumatic pumps, or gas well liquids operations. Thus, compliance with EPA's proposed BSER ensures that pneumatic controllers, pneumatic pumps, and gas well liquids operations are not "stationary sources" because compliance will not, and could not, result in emissions. According to the commenter, this exceeds EPA's authority granted under Clean Air Act (CAA) section 111. The commenter requests that EPA define the NSPS OOOOb pneumatic controller and pneumatic pump affected facilities as equipment designed to emit VOC and/or methane and similarly define the EG OOOOc designated facility to include equipment designed to emit methane.

Commenter (2391-CEC) states pneumatic pumps relying on supplied air do not meet this definition because they are not natural gas driven. Furthermore, the commenter adds that there is no environmental benefit to keeping or submitting this information. The commenter recommends that the EPA delete any reporting or recordkeeping requirements for these pumps from the final regulations.

Response II-8-7: It appears some commenters mistakenly thought the EPA included all pumps in the affected facility definition. The December 2022 Supplemental Proposal only included pumps driven by natural gas in the affected facility definition in §60.5365b(h); however, it did require that records be kept of the pumps that were not driven by natural gas and not included in the affected facility definition. The pump affected facility was defined as follows in the December 2022 Supplemental Proposal:

Each pneumatic pump affected facility, which is the collection of natural gas-driven diaphragm and piston pneumatic pumps at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. Pneumatic pumps that are not driven by natural gas are not included in the pneumatic pump affected facility, provided the records in §60.5420b(c)(15)(i) are maintained.

The EPA agrees that pumps with no potential to emit methane or VOC to the atmosphere should not be included in the affected facility and is finalizing this affected facility definition. After considering these comments regarding the recordkeeping and reporting requirements for pumps

with zero emissions, we have determined that it is appropriate in this instance to require identification of the equipment that is included in the affected facility, rather than the equipment that is not part of the affected facility. The pumps included in the affected facility are those that are subject to the emissions standards in the rule, whereas pumps not included in the affected facility are not subject to the emissions standards in the rule, and also have no potential to emit methane or VOCs. Therefore, we have revised the recordkeeping and reporting requirements to require identification only of pumps that meet the finalized definition of an affected facility, which are those pumps that are driven by natural gas and that are in operation for 90 days or more in a calendar year.

### ***8.1.6 Modification/Reconstruction***

Comment: Commenter (2428-API) states NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, the commenter explains that these pumps are already controlled by at least 95 percent. The commenter suggests that the EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, they state that these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. They add that they believe that these pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

Response II-8-8: NSPS OOOOa at §60.5393a(b) requires that natural gas-driven diaphragm pumps at well sites must reduce natural gas emissions by 95% if a control device is onsite and must route those pump emissions to another control device if the only control device(s) at the site achieve less than 95% emissions reductions. If no control device is onsite, OOOOa does not require emissions reductions from pumps. For the December 2022 Supplemental Proposal, we re-evaluated pump options that would result in zero emissions of methane and VOC, and we also evaluated the use of new and existing control devices in our analysis. For the final rule, we have updated the analysis performed for the December 2022 Supplemental Proposal to include more recent cost information for pump zero-emissions options. For both the supplemental proposal and the final rule, our analyses showed that zero emissions represents the BSER at sites with certain characteristics, including having access to electricity at the site and having a certain number of diaphragm pumps at the site. While the analysis conducted for the December 2022 Supplemental proposal showed that the costs to achieve zero emissions from pumps were reasonable when the site has access to electricity and when there were four or more diaphragm pumps at a site without electricity, the analysis conducted for the final rule using the updated information shows that costs to achieve zero emissions from pumps are reasonable when there is access to electricity and when there are three or more diaphragm pumps at a site without electricity. For sites with access to electricity and for sites without electricity that have three or more natural gas-driven diaphragm pumps, 95% control was not determined to be the BSER and was not used to develop the pump standards for the NSPS or the presumptive standards for the EG. Zero emissions from pumps was shown in our analyses to be technically achievable and cost-effective through several available options, including the use of electrical pumps powered by electricity from the grid or solar power systems, pumps powered by compressed air using electricity from the grid, and by routing emissions to a process. Since these options achieve a rate of zero methane and VOC emissions, compared to an emission rate of up to 5 percent of the

baseline emissions through the use of a control device, we have not changed our determination that a zero-emissions option is the BSER at these site types. For sites without electricity and with fewer than three natural gas-driven diaphragm pumps, our analysis for the final rule shows that control of emissions through a control device otherwise onsite represents the BSER. At these sites, requiring zero emissions from pumps, requiring the use of a new control device, and requiring the routing of pump emissions to a process through a new vapor recovery unit (VRU) (which is usually required to attain the necessary pressure for the gas to enter a process onsite) does not represent the BSER due to the costs associated with the equipment needed for these options. The NSPS and the EG for these sites reflect the BSER determination by requiring that emissions be routed to a process through a VRU if a VRU is onsite; if a VRU is not onsite, pump emissions are required to be routed to a control device onsite that achieves 95% emissions reductions; if no control device that achieves 95% emissions reduction is onsite, another onsite control device may be used; and if no VRU or control device is onsite, pump emissions are not required to be controlled. For existing sites that have access to electrical power or that have three or more diaphragm pumps, owners/operators currently complying with OOOOa by routing emissions to a control device achieving 95% control will be required to switch to a zero-emissions option for pumps to comply with OOOOc. For existing sites that do not have access to electrical power or that have fewer than three natural gas-driven diaphragm pumps, owners/operators currently complying with OOOOa by routing emissions to a control device achieving 95% control will be required to switch to routing emissions to a process if a VRU is onsite, otherwise, they may continue to route emissions to a control device achieving 95% control for compliance with OOOOc.

Comment: Commenter (2177-Southern Ute) states that the theory that owners and operators will implement zero-emission pumps across a site when a modification occurs because converting a single zero-emitting device typically requires a conversion of all devices at the facility is accurate. The commenter argues the infeasibility of implementing zero-emission pumps. The commenter notes that, due to lack of power in many remote locations, the installation of power may be cost prohibitive, and installation of combustion-generated power may create more emissions than are being reduced. They add that construction projects on Tribal lands require permitting through the National Environmental Policy Act (NEPA) program, which can be extensive and burdensome.

Response II-8-9: As explained above in Response II-8-8, the EPA conducted an analysis of pump control options for the December 2022 Supplemental Proposal and a revised analysis for the final rule. Both analyses showed that there are zero-emissions options for pumps at remote locations that do not have access to electrical power. The analysis for the final rule showed that zero emissions options at sites without electricity that have three or more natural gas-driven diaphragm pumps are reasonable, considering the emissions reductions, costs, and other impacts associated with those options.

As we assumed some sites would choose to install an electric generator to power compressed air-driven pumps, we estimated the emissions that would be created by such generators. We found that those emissions are relatively small and are outweighed by the emissions reductions that would be reduced from the pumps. Generators, which produce power by burning a fuel, such as natural gas or diesel, will generate a small amount of emissions from this process. As we

assumed some sites would choose to install an electric generator to power compressed air-driven or electrical pumps, we estimated the emissions that would be created by such generators. For this analysis, we included natural gas generators of 5 to 10 horsepower, which should be sufficient sizes to accommodate approximately 5 to 50 pumps. We estimate that a natural gas-powered generator would produce between 0.006 and 0.012 tons of VOC and between 0.15 and 0.3 tons of NOx per year, depending on the number of pumps and the size of the generator needed to power them. However, the emissions reduced through the use of zero-emission pumps powered by such generators would range from 4.8 to 48 tons of VOC and 17 and 170 tons of methane per year. Therefore, we found the emissions created by generators to be relatively small and are outweighed by the emissions reductions that would be reduced from the pumps. Therefore, consideration of these impacts did not change the BSER determination or the requirements of the NSPS or EG.

Regarding administrative burdens related to permitting, the EPA understands that permitting actions may be required when adding or changing equipment at a facility. However, such permitting is not directly required by this rulemaking and is outside the scope of this action.

Comment: Commenter (2433-Environmental Defense Fund (EDF) *et al.*) supports EPA's interpretation of "modification". The commenter explains that the addition of routed natural gas-driven pumps should trigger a modification. As with controllers, the commenter notes that the fact that most mitigation solutions are site-wide supports that the appropriate affected facility definition should include the collection of pumps at a site. Because both zero-emission and natural gas-driven mitigation technologies (including control devices and systems that route to process) are typically site-wide solutions, EPA's affected facility and modification definitions in this context are reasonable. The commenter also supports EPA's proposal to interpret "reconstruction" of a site as whenever greater than 50 percent of the existing onsite pumps are replaced over a two-year period. Just as with pneumatic controllers, the commenter states that this definition for pneumatic pumps aligns with the statutory definition that reconstructed sources are those where the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." Thus, the commenter believes that the EPA's interpretation is appropriate, and they encourage the agency to clarify, as it should with controllers, that pumps that are part of replacement programs that commenced within the two-year period are included in the threshold determination.

Response II-8-10: This comment is largely supportive of an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required for those supportive remarks. Regarding the request for clarification about the period of time included in the threshold determination for modifications and reconstructions, we note that the proposed NSPS OOOOb and EG OOOOc already included provisions that those threshold determinations must include all natural gas-driven pneumatic pumps which are or will be replaced within any 2-year rolling period. To provide further clarification on the replacement period time period, the final rule specifies that all replacement programs that commence in a 24-month rolling period are included in the threshold determinations for modifications and reconstructions.

Comment: Commenters (2254-Permian Basin Petroleum Association, 2305-Williams, 2283-Endeavor Energy Resources, L.P. (Endeavor)) note one of EPA’s rationales is the assumption that the addition of a controller or a pump would “represent a physical change to the site” and, by default, “would result in an increase in emissions.” However, they suggest that support for EPA’s rationale—that the addition of a controller or pump would result in an increase in emissions—is not reflected in the proposed rule text. To conform the rule text to EPA’s rationale and historic practice, commenters request that EPA should at the least clarify in the rule text that, for purposes of the collection of controllers or pumps at a site, a modification occurs only when a natural gas-driven pneumatic controller is added. Commenter (2305-Williams) notes that the proposed definition would result in a facility being “modified” even if it adds a non-natural gas pneumatic pump to an affected facility. The commenter explains that, having now undergone a “modification”, the owner or operator must now transition all its pneumatic pumps to non-natural gas driven pumps. The commenter contends that this is an unreasonable and impermissible result under the CAA and conflicts with EPA’s own regulations. The commenter (2305-Williams) requests that EPA modify proposed 40 CFR 60.5365b(h)(1) as follows:

...a modification occurs when an owner or operator increases the number of natural gas-driven pneumatic pumps at the pneumatic pump affected facility that it owns or operates at a site is increased by one or more which results in a net emissions increase from the affected facility.

Response II-8-11: While it was our intention in the December 2022 Supplemental Proposal to only include the addition of natural gas-driven pumps in the conditions that would constitute a modification, as only those pumps could increase emissions, we agree that the proposed regulatory text did not specify this. We therefore have revised the regulatory language to clarify that the addition of one or more natural gas-driven pumps to a site constitutes a modification. We also are clarifying in the final rule that reconstruction would be considered to occur whenever greater than 50 of the number of existing onsite natural gas-driven pumps are replaced.

Comment: Commenter (2202-Texas Oil & Gas Association (TXOGA)) states that the December 2022 supplemental proposes to “include a second, simplified method of determining whether a pump replacement project constitutes reconstruction under 40 CFR 60.15(b)(1) whereby reconstruction may be considered to occur whenever greater than 50 [sic] of the number of existing onsite pumps are replaced.”<sup>1</sup> The commenter believes EPA accidentally omitted the word “percent” after “50” in the preceding paragraph because elsewhere in the supplemental notice, it is proposed that “the standard in 40 CFR 60.15(b)(1) specifying that the ‘fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility’ can [now] be met through a showing that 50 percent or more of the number of existing onsite pumps are replaced.”<sup>2</sup> The commenter requests that the EPA clarify this language before publishing a final rule.

Response II-8-12: We agree the word “percent” was inadvertently omitted from the preamble in this sentence; however, the regulatory text of the December 2022 supplementary proposal correctly included “percent” in each instance where it should have been written. The regulatory

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<sup>1</sup> 87 Fed. Reg. at 74,773.

<sup>2</sup> Id.



text of the final rule includes “percent” where it should be included, and the requirements related to the conditions that constitute a reconstruction for pumps should be clear to readers.

Comment: Commenters (2326-AXPC, 2391-CEC) request that EPA specifically exclude temporary pumps from the affected facility definition.

Commenter (2326-AXPC) provides that NSPS OOOOb excludes from the pneumatic pump affected facility definition “[a] single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year.” The commenter reports that EG OOOOc contains no such exclusion; however, EG OOOOc requires that operators maintain records of “[i]dentification of each pneumatic pump that is not driven by natural gas or single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year and is not a pneumatic pump designated facility as specified in §60.5386c(g).” Given the language of the recordkeeping requirements, the commenter requests that the EPA clarify that limited-use (less than 90 days) natural gas-driven diaphragm pneumatic pumps are excluded from the EG OOOOc pneumatic pump affected facility definition. The commenter (2326-AXPC) requests that EPA add the following subparagraph to 40 CFR 60.5386c(g):

(1) A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not part of a designated facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420c(c)(14)(i). For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.

Commenter (2391-CEC) states EPA should exempt pneumatic controllers and pumps located on temporary or portable equipment from the proposed zero emission standard if the temporary pneumatic device remains onsite for less than 180 days. Feasibility and cost-effectiveness are not justified for its type of pumps to be connected to the grid. The commenter also states EPA should also exempt temporary pneumatic diaphragm pumps. The commenter notes that an example of the temporary use of such devices is for circulating glycol for heat trace as part of winterization efforts to prevent freezing. The commenter suggests that EPA could do so by amending the proposed NSPS OOOOb and EG OOOOc regulations to incorporate language like that in 40 CFR 60.5430a.

Commenter (2428-API) suggests that 40 CFR 60.5365b(h)(3) should also include an exemption for piston pumps. The commenter explains that temporarily used piston pumps emit very little, which is why they have historically been exempt from the control standards. According to the commenter, such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA’s intent to also include piston pumps in this provision.

Response II-8-13: As proposed in the NSPS OOOOb, the EPA is finalizing the definition of an affected facility that includes only natural gas-driven pumps that are in operation for 90 days or more in a calendar year. This definition of the affected facility already excludes equipment that is used temporarily (i.e., those used for less than 90 days). Commenters did not provide any rationale for the use of a different understanding of what is “temporary” for a pump, and a

review of state regulations for oil and gas operations, including those of Colorado and New Mexico, revealed that these rules also include a 90-day threshold for “temporary” pumps. Therefore, we have retained the 90-day threshold for the natural gas-driven pumps that need to be included in the affected facility.

Regarding the application of this 90-day threshold to both piston and diaphragm pumps, we agree that this is appropriate, and we note that piston pumps were inadvertently excluded in the December 2022 Supplemental Proposal regulatory language. We have revised the regulatory language accordingly to include both pump types.

Regarding the inclusion of the 90-day threshold in the EG of OOOOc, similar to the exclusion of piston pumps, we agree that including the 90-day threshold in OOOOc is appropriate, and we note that this provision was inadvertently excluded from the affected facility definition in the OOOOc December 2022 Supplemental Proposal regulatory language. We have revised the regulatory language of OOOOc accordingly to include this 90-day threshold.

Comment: Commenter (2428-API) states it is unclear how the notifications from 40 CFR 60.15 apply to the reconstruction provision proposed. Similar to natural gas-driven pneumatic controllers, the proposed language in 40 CFR 60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in 40 CFR 60.15, which include 60-day notification and Administrator approval. According to the commenter, this directly conflicts with information presented in Table 5 that states 40 CFR 60.15(d) does not apply to pneumatic pumps. The commenter believes it was EPA’s intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

Response II-8-14: We agree that we did not intend for facilities to be required to notify the Administrator of upcoming pump replacements that would constitute a reconstruction or for the Administrator to be required to review the notification and determine whether the replacements constitute a reconstruction. We have revised the final regulatory text to not refer to the requirements of 40 CFR 60.15(d) and have kept the information presented in Table 5 of the proposed regulatory text, which states that 40 CFR 60.15(d) does not apply to pumps.

## **8.2 NSPS OOOOb and EG OOOOc Control Options**

### ***8.2.1 General Support for Proposed Standards***

#### **8.2.1.1 Overall Support for Proposed Standards**

Comment: Commenters (1611-East Liberty Presbyterian Church, 1649-Sisters of St. Francis of Philadelphia, 2152-California State Teachers' Retirement System, 2156-Catholic Charities of Gallup Diocese, 2163-Federated Hermes Limited, 2164-Nordea Asset Management, 2184-Physicians for Social Responsibility Climate Ambassador, 2185-New York State Comptroller, 2190-Miller/Howard Investments, Inc., 2191-Boston Trust Walden Company, 2199-Rocky Mountain Farmers Union *et al.*, 2203-Ceres, Inc., 2206-Legal & General Investment Management America, Inc., 2209-Public Land Solutions, 2212-Union of Concerned Scientists,

2236-Physicians for Social Responsibility Pennsylvania, 2242-Seventh Generation Interfaith, Inc., 2249-NACAA, 2285-Bailard, Inc., 2287-Interfaith Center on Corporate Responsibility, 2299-NEI Investments, 2303-NTAA, , 2347-Clarke, 2348-Energy Workforce & Technology Council, 2352-Environment Texas Research and Policy Center, 2388-ExxonMobil, 2394-Earthworks, 2410-CA AG *et al.*, 2424-As You Sow, 2433-EDF *et al.*, 2441-Breathe Utah *et al.*, 2459-BMO Global Asset Management, 2461-Conservatives for Responsible Stewardship and Vet Voice Foundation, 2766-1000 Grandmothers for Future Generations) express support for phasing out of polluting pneumatic pumps in favor of zero-emitting alternatives. Commenter (2388-ExxonMobil) supports devices being granted limited exemptions where technical or safety limitations exist.

Commenter (2627-British Columbia Investment Management Corporation (BCI)) supports the expansion of the November 2021 proposed standards for pneumatic pumps/controllers. The commenter states that the stronger standards address one of the largest sources of methane pollution. In addition to requiring the phaseout of polluting pneumatic controllers and pumps in favor of zero-emitting alternatives, they believe that prohibiting the use of natural gas to power pumps and controllers will contribute to decreasing GHG emissions without requiring large investments, as non-emitting pneumatic controllers and pumps are inexpensive and readily available. The commenter commends the EPA for providing some flexibility for remote sites without electricity, if it has been demonstrated that it is not technically feasible to forego from using natural gas, as long as the installation of solar-powered controllers with batteries remains unreliable.

Response II-8-15: These comments are supportive comments on aspects of the December 2022 Supplemental Proposal that have remained unchanged in the final rule; as such, no response is required.

#### 8.2.1.2 Support Proposed Standards (Without Technical Infeasibility Exemption)

Comment: Commenter (2433-EDF *et al.*) states that Analysis Group Report<sup>3</sup> shows that for sites without electricity, solar pneumatic controller and pump systems are cost-effective at sites across the U.S., even in states with colder temperatures. They note that there is also evidence that zero-emission pumps are readily available and already being deployed in numbers. British Columbia and Alberta do not allow new emitting pumps. Additionally, the commenter adds that the Datu report<sup>4</sup> identified 13 suppliers of solar-based systems that can be used in remote locations or at sites without electricity, including nine providers of instrument air solar compressors and four providers of solar-driven electric actuators. As EPA itself notes, this equipment can be used for pumps in addition to controllers,<sup>5</sup> demonstrating the availability of suppliers of this type of

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<sup>3</sup> Analysis Group, Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power ZeroEmission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations, at 17–18, 46 (May 6, 2022) [hereinafter Analysis Group Report] (included as Attachment M of the commenter’s submitted comments.).

<sup>4</sup> Datu Research, Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand? (Jan. 2023). (Included as Attachment P of the commenter’s submitted comments.).

<sup>5</sup> See 87 Fed. Reg. at 74770 (“In addition, some of the means of powering a pneumatic pump without the use of natural gas can also be used to power pneumatic controllers. While our updated BSER analyses for pneumatic

technology. Further, the commenter notes that Pump Projects provides solar electric pumps with compressed air instrumentation,<sup>6</sup> and EPA cited several vendors who confirmed during the rulemaking process the successful implementation of pumps not driven by natural gas at remote locations, including locations with very harsh winter weather.<sup>7,8</sup>

The commenter (2433-EDF *et al.*) also notes that EPA has determined that routed pumps are cost-effective and has included them as an option in the proposed NSPS OOOOb. As with the controller standard, the zero-emission pump standard that allows these types of pumps would provide the flexibility needed to remove a technical infeasibility exemption for sites without electricity. The commenter contends that the comments that EPA cites in the December 2022 proposal maintaining that “zero-emission pneumatic pumps are technically infeasible at sites without electricity” are not compelling. The commenter provides that one of the two cited comments simply states that “[z]ero-emissions pneumatic pumps are technically infeasible for our sites,” due to lack of electricity, and that “[s]olar-powered pumps are not reliable for 24/7 operation in geographic locations that receive extended periods of cloud cover or snowfall,” without providing any documentation or further arguments to support these claims. However, the evidence record shows that solar pumps have been shown to operate successfully in areas with harsh winter conditions, including the Wamsutter Basin in Wyoming, and that zero emissions pumps are required for new pumps province-wide in Alberta and British Columbia, where snowfall, cloud cover, and winter insolation conditions are all more challenging for solar than in the contiguous U.S. The commenter notes that the second of the two cited comments does not make any specific claim about solar-powered pumps per se, but rather claims that onsite solar/battery systems designed to serve both non-emitting pumps and non-emitting pneumatic controllers are “uncommon [and] unreliable.” However, according to the commenter, the evidence clearly shows that these systems are reliable, as the EPA has found for controllers. The commenter recommends that, since the solar/battery technology that serves non-emitting pumps is the same as that which serves non-emitting controllers, the EPA should recognize that concerns about the performance of these systems for non-emitting pumps are unfounded.

Commenter (2433-EDF *et al.*) asserts that an exemption for sites without electricity would be incredibly difficult to monitor and could negate the EPA’s otherwise strong pump standard. As it stands, the commenter states that the exemption allows the venting of gas from up to three pumps at sites without electricity and allows operators to self-certify with written statements that non-emitting options (solar-powered pneumatic pumps and generators for compressed air systems) and routing to capture and control are infeasible at a given location. Fraudulent

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pumps and pneumatic controllers evaluated the cost effectiveness of these sources independently, the shared usage of solutions for the two sources, such as compressed air systems, solar-powered systems, or generators, will result in even lower overall site-wide cost effectiveness values.”).

<sup>6</sup> Pump Projects, Instrument Air, [https://pumpprojects.com/products/instrument\\_air/](https://pumpprojects.com/products/instrument_air/) (last visited Feb. 12, 2023).

<sup>7</sup> 87 Fed. Reg. at 74772.

<sup>8</sup> See also, Rutherford et al., Closing the methane gap in US oil and gas and natural gas emissions inventories, 12 Nature Comms. (Aug. 5, 2021), <https://www.nature.com/articles/s41467-021-25017-4>; Marc Mansfield et al., Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin (July 17, 2017), <https://documents.deq.utah.gov/air-quality/planning/technical-analysis/DAQ2017-009061.pdf>; Lesley Fleischman et al., Clean Air Task Force, Tank Emissions from Controlled Tanks,

[https://www.epa.gov/sites/default/files/201711/documents/5\\_catf\\_tank\\_presentation\\_for\\_inventory\\_workshop\\_final.pdf](https://www.epa.gov/sites/default/files/201711/documents/5_catf_tank_presentation_for_inventory_workshop_final.pdf) (last accessed Feb. 10, 2023).

statements will be subject to civil and potentially criminal penalties. However, the commenter suggests that, because the EPA provides no definition for “technical infeasibility” here or any guidance on how it would evaluate such claims, operators will have plenty of leeway to craft their own exemption from the standard in a way that may not be considered fraudulent. In this way, the commenter believes that the self-certified exemptions will swallow the rule that EPA has determined is the BSER for sites with up to three pumps, but which do not have electricity, and the cumulative emissions resulting from pumps at these sites will continue to be significant and detrimental to the environment and people’s health.

Response II-8-16: We agree with the commenters that the use of solar-powered pumps appears to be a cost-effective option for use at sites without access to electricity and that solar-powered pumps can be used in some situations. However, due to the high power needs of some pumps, the EPA acknowledges industry concerns about their technical feasibility in many common situations experienced at oil and gas sites. Due to uncertainty about whether they have been adequately demonstrated for these applications, the EPA concluded that it is not appropriate to establish BSER based solely on solar-powered pumps. At sites with fewer than three natural gas-driven pumps and without access to electrical power, solar-powered pumps are the only cost-effective zero-emissions option available. For these sites, the NSPS and the EG reflect the determination that BSER is the use of emissions reduction equipment that is already onsite. For these sites, pump emissions must be routed to a process through a VRU if a VRU is onsite; if a VRU is not onsite, pump emissions are required to be routed to a control device onsite that achieves 95% emissions reductions; if no control device that achieves 95% emissions reduction is onsite, another onsite control device may be used; and if no VRU or control device is onsite, pump emissions are not required to be controlled. Since these requirements are based on the use of existing equipment, it may not be feasible in all situations to use that equipment to control a site’s pump emissions. To account for this in the final rule, the EPA is retaining the proposed infeasibility demonstration requirements for this limited subset of pump sites. For these sites, which do not have access to electrical power and that have fewer than three natural gas-driven diaphragm pumps, the rule allows owners/operators to demonstrate infeasibility of the compliance methods according to the hierarchy of methods specified in the rule. For example, if a VRU is onsite, the owner/operator could demonstrate that it is technically infeasible to route pump emissions through the VRU to a process, and then proceed to route emissions to a control device that achieves a 95% reduction in emissions.

### ***8.2.2 Access to Electricity***

Comment: Commenter (2483-Interstate Natural Gas Association of America (INGAA)) states that they appreciate that EPA provided an alternative non-zero emission standard for pneumatic pumps where certain conditions exist at sites without electric supply (*i.e.*, it is technically infeasible to use a solar powered pneumatic pump and technically infeasible to install a compressed air system powered by either a natural gas-driven generator or a solar power generator).

Commenter (2321-Apollo Exploration and Development, Inc. (AED)) states EPA’s new requirement that equipment must be powered by electricity poses serious challenges to rural oil and natural gas fields that will not have easy access to electric power.

Commenter (2283-Endeavor) provides that many well sites in the Midland Basin are located in remote locations without access to an existing grid. Even if a grid is theoretically accessible, the commenter notes that it is not always logistically feasible to connect to that grid due to issues outside of an owner or operator's control. The commenter explains that these challenges include right-of-way issues for placement of power lines, a landowner's right to not install power lines on their property, and/or distance from an available power line that contains sufficient power and capacity to connect the facility. For those well sites that happen to be in proximity to a grid, or where it might be technically feasible to connect them to a grid, current electricity generation in many producing regions (such as the Midland Basin) will not be adequate to accommodate EPA's proposed requirements while also balancing competing load demands.

Commenter (2283-Endeavor) states alternative on-site power systems-at the scale necessary to power a site's myriad operations-may not be feasible as a meaningful and reliable replacement for a traditional power grid. Well site operations require power during all hours of operations, including for safety reasons, not just when there is sunlight. Accordingly, incorporation of intermittent renewable power sources into operations may not be practicable.

Commenter (2301-U.S. Chamber of Commerce (USCC)) expresses concern that the proposed requirements do not recognize the practical reality that many of these sites are unmanned and located in isolated regions with limited onsite or surrounding infrastructure.

Commenter (2202-Texas Oil & Gas Association) notes that the December 2022 Supplemental Proposal (see section IV.E.1 of the December 2022 Supplemental Proposal preamble)<sup>9</sup> for pneumatic pumps states that “all natural gas processing plants have access to electrical power,” however, it also states that “at sites without access to electricity” a “tiered structure” that accounts for “flexibility based on site-specific conditions” is prudent. To the extent that these statements are inconsistent, the commenter requests that EPA remedy these inconsistencies and any underlying analysis affected by such statements before publishing a final rule.

Response II-8-17: The EPA understands that sites with pumps may not have access to electrical power. There are several options available to such sites to meet the NSPS and EG. These include the use of solar-powered pumps, the use of compressed air-driven pumps powered by a generator, and routing emissions to a process. For sites without access to electricity and fewer than three natural gas-driven diaphragm pumps, existing control devices may also be used to comply with the rule requirements, if a VRU is not onsite to route emissions through to a process. The EPA also notes that solar-powered pump systems include batteries that are typically sized to contain a 10-day power supply, and this battery power ensures continuous pump operations. With regards to the commenter (2202-Texas Oil & Gas Association) that requests that EPA remedy inconsistencies, there are no inconsistencies as written. It is EPA's understanding that all natural gas processing plants have access to electrical power, which is why the preamble also states that “[s]ince all natural gas processing plants have access to electrical power, we only evaluated compressed air systems for this segment.” The flexibility for sites without access to “electricity” and analyses correctly included the tiered structure for other segments.

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<sup>9</sup> 87 FR 74769-74770.

### 8.2.3 Solar

Comment: Commenter (2252-Petroleum Association of Wyoming, 2391-CEC) states solar panels can be covered with snow and ice, or there could be several days of cloudy weather where solar power generation is not sufficient to keep batteries charged enough to supply the amount of power necessary to run operations. The commenters stress that reliability is incredibly important as failure of devices may lead to serious safety and environmental incidents.

Commenter (2301-USCC) states onsite solar-power systems with battery storage may only be able to provide intermittent power that presents inherent reliability risks. For example, the commenter notes that power reliability at large-scale solar applications during the winter months are of considerable concern, when there is less sunlight, more cloud coverage, and increased snow cover. The add that battery capacity drops drastically at below the freezing point.

Commenter (2321-AED) states that solar alternatives are not reliable in Michigan weather conditions, which could cause a serious problem at a well site if equipment goes down. The commenter notes that the proposed rules need to reflect this reality and offer exceptions to this requirement when reliable electricity is not viable.

The commenter (2321-AED) is also concerned that the necessary resources for potential work to achieve compliance will not be available in terms of manpower and battery equipment additions. It has been a struggle to get work accomplished in the field and the commenter is afraid of how much work they will need to do and who is going to do it when it needs to be done.

Response II-8-18: The EPA maintains that solar-powered pumps can be used in many situations. Solar-powered pump systems are designed and sized with consideration of geographic location and the requirements for the pump, such as the amount of chemical to be injected and the injection pressure for a chemical injection pump. For systems located in less sunny locations, the configuration of solar panels and battery capacity may be different from that used in an area with high solar irradiance. In addition, batteries are typically sized to contain a power supply of several days, which ensures continuous pump operations.

Due to the high power needs of some pumps, the EPA acknowledges industry concerns about their technical feasibility in many common situations experienced at oil and gas sites. Considering the uncertainty about whether solar-powered pumps have been adequately demonstrated for these applications, the EPA concluded that it is not appropriate to establish BSER based solely on solar-powered pumps. At sites with electrical power or with three or more natural gas-driven diaphragm pumps, other compliance methods are available, including the use of grid-powered electrical pumps, compressed air-driven pumps, and routing pump emissions to a process. At sites with fewer than three natural gas-driven diaphragm pumps and without access to electrical power, a hierarchy of emissions control methods is required, and the NSPS and the EG reflect the determination that BSER is the use of emissions reduction equipment that is already onsite. Therefore, solar-powered pumps and other zero-emissions pump options are not required to be used at these sites.

#### **8.2.4 Generators**

Comment: Commenter (2220-Wyoming Department of Environmental Quality (WDEQ)) states the use of gas-powered generators as a substitute to power pneumatic pumps poses a concern because, even though the gas-powered generators would have to undertake their state's New Source Review (NSR) permitting process, their operation nevertheless could result in increased cumulative nitrogen oxide (NOx) and VOC emissions from sites implementing them; gas-powered generators or other approaches like air compressors or micro-turbines would run at all times as opposed to the intermittent function of pneumatics that periodically vent emissions. According to the commenter, this is particularly problematic in the Upper Green River Basin (UGRB) marginal ozone nonattainment area, where reducing NOx emissions has been a key area of their state's policy focus for over a decade to reduce the potential for wintertime ozone formation. Put simply, they note that there are emissions trade-offs that will occur when using gas-powered generators or air compressors to power pneumatics. Additionally, they add that using generators or other related alternative approaches is simply not cost-effective for operators.

Response II-8-19: As we assumed some sites would choose to install an electric generator to power compressed air-driven pumps, we estimated the emissions that would be created by such generators. We found that those emissions are relatively small and are outweighed by the emissions reductions that would be reduced from the pumps. See Response II-8-9 for further details.

#### **8.2.5 Route to Control**

Comment: Commenter (2177-Southern Ute) states that routing vapors to a process would likely require some kind of compression to increase the pressure of the vapors from near atmospheric, to something higher than the pressure of the process they are being introduced into. In many instances, they note that this will require additional equipment to be installed, resulting in an increase in facility emissions, and should be taken into consideration when requiring these types of controls.

Response II-8-20: As we assumed some sites would choose to install an electric generator to power a VRU to route emissions to a process, we estimated the emissions that would be created by such generators. We found that those emissions are relatively small and are outweighed by the emissions reductions that would be reduced from the pumps. For a VRU, it is assumed that the larger size of generator analyzed would be needed. See Response II-8-9 for further details.

Comment: Commenter (2220-WDEQ) states their state's compliance staff repeatedly raised concerns that owners/operators of sites with older equipment often run into technical problems as they attempt to retrofit and make changes to process equipment. According to the commenter, this practice often creates a cascading effect on other equipment on site, resulting in more unrelated compliance issues arising in other parts of the process and, as an unintended consequence of the rule, potentially higher emissions. Put simply, the commenter contends that re-routing to a process on site is not a practical or economically feasible solution for many existing sources and can result in unanticipated emissions increases due to other consequential compliance issues. This, in turn, results in an increased workload for their state's compliance



staff who will already face a significantly increased burden in site visits and reports due to the increased number of affected facilities because of the supplemental proposal.

Response II-8-21: While the EPA recognizes the possibility that changes made to processes or equipment at a facility may initially create unintentional issues or problems at the site. However, as the NSPS and EG requirements reduce emissions by 95% to 100% from all pump affected facilities, the guaranteed benefits of these long-term emissions reductions outweigh any potential initial issues that might arise as process or equipment modifications are made.

Comment: Commenter (2391-CEC) provides that the EPA proposes to allow operators to route to a control device, but only if they can demonstrate that routing to a process is technically infeasible. Thus, only after making both infeasibility demonstrations can the operator route the pumps to an existing control device. The commenter urges the Agency to recognize the substantial investments that operators have already made to route emissions from pneumatic pumps to control devices by allowing any natural gas-driven pneumatic device to be routed to controls—not only in situations where non-natural gas technology and routing to a process are each technically infeasible.

The commenter (2391-CEC) requests that, if the final rule requires operators to demonstrate the technical infeasibility of non-natural gas pumps, EPA expand the remaining analysis for routing an existing pneumatic pump to a control device to weigh the potential emission reduction benefits with the costs. The commenter explains that retrofitting existing diaphragm pumps is likely to be very expensive compared to routing these devices to existing controls. As a result, the commenter states that few emission reductions could be achieved over routing to controls are not going to be cost-effective. According to the commenter, to ignore economic viability would result in a rule that does not provide “achievable, cost-effective measures to significantly reduce methane and VOC emissions, consistent with the requirements of section 111 of the CAA.” See 87 Fed. Reg. at 74705.

Response II-8-22: The final rule allows for owners/operators at sites without electricity and fewer than three diaphragm pumps to route pump emissions to a process if a vapor recovery unit is onsite, or to an onsite control device if there is no vapor recovery unit onsite. No demonstration of the technical infeasibility of non-natural gas pumps is required. As routing pump emissions to a process would achieve 100% control of emissions and control devices would achieve less than this reduction, the final rule requires that emissions be routed to a process if a VRU is onsite before routing emissions to an onsite control device could be considered.

For the final rule, the EPA conducted an analysis of the emissions reductions, costs, and other impacts of the options available to achieve zero emissions from pumps and found that for sites with electricity and for sites without electricity and three or more natural gas-driven diaphragm pumps, there were at least two options available to achieve zero emissions at a reasonable cost. Therefore, the EPA concluded that zero-emissions represented the BSER, and the NSPS and EG reflect this determination by requiring zero emissions from pumps at these sites. For sites that route emissions from pumps to a process, no demonstration of infeasibility of using non-natural gas pumps is required. For sites without electricity and fewer than three natural gas-driven

diaphragm pumps, the EPA found the only zero-emissions option that could be implemented at a reasonable cost was solar-powered pumps. Due to the potential technical infeasibility of using solar-powered pumps for all site applications, the EPA determined that zero-emissions did not represent the BSER for these sites. The EPA further determined that costs for controlling emissions by routing the emissions to a control device or to a process through a VRU were only reasonable for these sites if there was a VRU or control device already or otherwise present. Therefore, considering the emissions reductions and the associated costs, the EPA determined that the BSER for these sites is the use of existing equipment to route emissions to a process or to a control device.

### ***8.2.6 Nitrogen Systems***

Comment: Commenter (1581-Kathairos Solutions US, Inc.) provides the following information regarding EPA nitrogen systems:

- Information describing specific situations where owners have captured gas from pneumatic pumps and routed it to a beneficial use: Nitrogen systems do not require gas to be captured or rerouted to eliminate methane venting without power. Natural gas is conserved for future sale.
- Information on the specific processes and types of equipment needed to capture and route the emissions, along with the costs: Nitrogen systems eliminate methane venting at an affordable rate, and no power is needed. There are no changes to existing devices, and no need to capture or route methane emissions. A nitrogen system is simply installed and tied into existing systems and the fuel line is turned off, keeping the natural gas for future sale.
- Information related to the Agency's understanding that routing emissions to a process reduces emissions by 100 percent: There is no need to capture or route emissions at remote wellsites with no power access. Using nitrogen eliminates emissions from pneumatics 100%; the commenter cannot speak to the efficacy of routing processes. However, the commenter does agree with EPA that steps must be taken to ensure emissions are eliminated from pneumatics at remote locations without electricity.
- Information about situations where a vapor recovery unit would be needed to enable the use of emissions from a pneumatic pump, along with the costs of those units: No vapor recovery units are needed to eliminate methane emissions from pneumatic pumps at remote wellsites when nitrogen systems are used. Nitrogen can be deployed reliably and economically at wellsites of all sizes and pressure requirements.

Response II-8-23: The EPA recognizes that compressed nitrogen could be used to power pneumatic pumps and that there are benefits to its use, such as having no secondary emissions at the site. The final rule is technology-neutral and allows for owners/operators to use this or other methods to meet the zero-emissions standard for pumps.

### ***8.2.7 Pneumatic Pumps Control Option Regional Considerations***

Comment: Commenter (2335-Private Citizen) states that recent studies have shown that climate warming in arctic regions is not twice that of the rest of the globe but about four times. The arctic

well sites might often be excused from some of the emissions standards due to their distance from electric supplies. The strictest of standards should be applied to all existing and any future oil and gas development projects northern Alaska. The commenter asserts that requiring all pneumatic pumps to have zero emissions is a step in the right direction.

Commenter (2483-INGAA) recommends that the alternative standard for areas in Alaska that lack electric supply and where it is technically infeasible to use a solar powered pneumatic pump and technically infeasible to install a compressed air system powered by either a natural gas-driven generator or solar powered generator should be available throughout the U.S.

Similarly, commenter (2220-WDEQ) requests, if EPA moves forward with the supplemental proposal's requirements for pneumatics, the same exemption as provided to pneumatic controller designated facilities located at a site in Alaska (see 40 CFR 60.5390b(b) in the proposed regulatory text for NSPS OOOOb and 40 CFR 60.5394c(b) in the proposed regulatory text for EG OOOOc). The commenter notes that the EPA's rationale for providing such an exemption is that there are facilities in Alaska that do not have access to electrical power due to Alaska's remote geography and the infeasibility of solar or other options. They explain that Wyoming's geography and climate are similarly remote in many parts of the state and operators run into the same infeasibilities as in Alaska. They contend that it is unfair for EPA to provide such an exemption specifically for sites in one state when there are other states that face essentially the exact same challenges. Furthermore, the commenter requests that EPA consider the harsh winter conditions in Wyoming with regards to how it poses compliance timing challenges in certain instances. They explain that there are potential situations where the frigid winter temperatures might not allow certain sites to perform required compliance duties within a 30-day period because the temperatures are so cold that it would require an operator to shut in a well to undertake compliance activities. Put simply, the commenter asserts that a "one-size-fits-all" rule does not account for these meteorological or geographical challenges and EPA should take this into consideration when revising the supplemental proposal.

Response II-8-24: The EPA notes that for pumps, the BSER determination was based on site conditions and reflects access to electricity and the number of natural gas-driven diaphragm pumps at the site but does not have an exemption for sites located in Alaska. The NSPS and EG requirements are based on the BSER determination, which requires zero emissions from pumps at sites with access to electrical power and at sites with three or more natural gas-driven diaphragm pumps. For sites without access to electrical power and fewer than three natural gas-driven diaphragm pumps, owners/operators are required to control emissions by using equipment or control devices already onsite.

### ***8.2.8 Pumps Should be Subject to LDAR***

Comment: Commenter (2248-North Dakota Petroleum Council) suggests that pneumatic pumps that do not bleed continuously and if found to do so during an optical gas imaging (OGI) camera inspection, should be considered as a fugitive leak subject to the repair timeframes in the LDAR requirements of the rule. Therefore, according to the commenter, the supplemental proposal requirements are prescriptive and will have negligible effect on emissions.

Response II-8-25: Diaphragm and piston pneumatic pumps, unlike controllers, are not designed for intermittent vent operation, but emit gas whenever they are pumping. While it is possible that there could be problems with pumps or their seals that result in additional emissions from leaks, such leaks are not the target of the NSPS and EG requirements for pumps. These requirements eliminate or greatly reduce the emissions that occur from the operation of the pump itself. In addition, where pumps not driven by natural gas are used, there would also be no potential for leaks of methane and VOC.

### **8.2.9 Technical Infeasibility**

Comment: Commenter (2433-EDF *et al.*) states because zero-emitting pumps are also feasible for operators at sites without electricity we urge EPA to finalize pump standards that mirror the proposed controller standards (including an allowance for routed natural gas-driven pumps in the baseline) and remove the tiered flexibility exemption. Critically, the commenter states that the EPA has determined that the BSER for pumps at both sites with and without electricity is zero-emitting pumps but permits the exemption for sites without electricity because it argues that there may be circumstances where the standard is infeasible. The commenter believes that installation of zero-emission pumps is feasible in all instances and that a feasibility exemption will create a significant loophole in a standard that the EPA has determined is the BSER. The commenter asserts that, even if EPA retains the exemption for sites without electricity, it must narrowly tailor the exemption. The commenter provides the following support for their position:

First, exemptions should not be available to operators that are converting a certain number of natural gas-driven controllers, and certainly all these controllers, or who have installed a number of site-wide systems that power non-natural gas-driven pneumatics. Limiting the exemption based on the percent of controllers converted or the number of site-wide systems installed is practical. Zero-emission controllers and pumps can share the same equipment (such as air compressors, solar panels, batteries, etc.). When operators install instrument air compressors or install solar arrays, those technologies can be used to power both controllers and pumps. Additionally, EPA's proposal discusses the cost-effectiveness of applying solutions site-wide and acknowledges that pump cost-effectiveness increases when controllers are on-site, due to the usage of shared equipment and our independent analysis demonstrates the cost effectiveness of site-wide zero-emitting solutions as well. As a result, zero-emission pumps should be required at facilities that already have the necessary infrastructure in place, since doing so would both result in greater emissions reductions and would be feasible and cost-effective.

Second, EPA must also strengthen the technical infeasibility showing. Specifically, to qualify, operators should have to show that they cannot use any of the many zero-emission pump options – including electric, solar, instrument air, and routed pumps. The commenter supports EPA's proposed requirements for the feasibility showing for solar and instrument air, but additionally would recommend the following: to demonstrate that use of electricity is infeasible, the operator must show that the relevant facility is in a remote location greater than 0.5 miles from the grid, as analyses show it is cost-effective to connect to the grid within that distance. To demonstrate that the use of solar is infeasible, operators must show why certain technical issues exist, such as those

associated with weather or temperature conditions. As EPA has proposed, operators should also need to show with specificity why routed pumps that achieve 100 percent capture are infeasible, and the commenter supports EPA's proposal for how operators would make that showing, including safety considerations, distance from a process, pressure losses, and other technical reasons.

Finally, upon an infeasibility showing, EPA should require operators to use a control device at all sites, even at sites with fewer than four pumps. As EPA notes, control devices are site-wide technologies that would usually—if not always—be used to avoid venting from just four pumps.

Commenter (2326-AXPC) expresses that the EPA does not provide any information within the rule on how an affected facility is expected to demonstrate that the regulatory provision in question is “technically infeasible”, other than a requirement that a professional engineer or other qualified individual so certify.

Because there is no explanation of technical infeasibility within the rulemaking, the commenter (2326-AXPC) reports that they evaluated what EPA has done in other CAA programs. For example, EPA's regulations related to best available retrofit technology (BART) determinations under the regional haze program include some insight into how EPA might evaluate technical feasibility considerations. According to EPA's BART regulations:

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” As explained in more detail below, a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

While the commenter (2326-AXPC) notes that these regulations provide more context than EPA's proposed NSPS OOOOb/EG OOOOc regulations, the BART regulation conflates economic factors and technical feasibility and does not specifically account for other factors related to potential implementation that may be critical to compliance. The “available” concept is inherently an economic concept as it relates to whether the item is commercially available – i.e., that the price is at such a level that it can be produced commercially. According to the commenter, if EPA was truly looking at considering technical feasibility without regard to economic viability, whether a technology is commercially available would be irrelevant. And to do so here, would be inappropriate, particularly given the definition of standard of performance. Under CAA section§ 111(a)(1), standard of performance means-

a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (taking into

account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator deems has been adequately demonstrated.

By providing an opt-out, the commenter (2326-AXPC) notes that the EPA inherently recognizes that BSER cannot be met at every facility. Thus, in making the demonstration that use of the opt out is appropriate, the costs of achieving such emissions reduction should be considered. Further, because EPA may only include standards that are determined to be adequately demonstrated, technical feasibility for the opt-out provisions in NSPS OOOOb/EG OOOOc, technical feasibility must include considerations such as: ability to access electrical power; landowner access; other local or state regulatory requirements; and other considerations that limit the ability to comply with the standard of performance. In other words, technical feasibility must include considerations beyond just physical impossibility. Anything that would preclude, or hinder implementation of the regulations should be included in a consideration of feasibility – whether technical, economic, or some other appropriate consideration. However, the commenter requests that the EPA be explicit that economics is to be considered in the feasibility analysis – as technical feasibility alone is insufficient.

Commenter (2221-TPA) suggests that the rules should allow in-house engineers, and non-professional engineer (PE) outside personnel, to make required certifications and determinations. With respect to certification requirements regarding determinations described in the proposed rules, the commenter supports the current proposal to allow certification by an in-house engineer instead of an outside engineer because in-house engineers are often the most experienced and knowledgeable personnel with respect to site design and control as well as specific design and feasibility questions. As such they are often the most qualified personnel to make the assessments for which certifications are required.

The commenter (2221-TPA) also believes that the EPA should expand the universe of persons who could make required certifications and determinations to include non-PE outside personnel. The commenter explains that companies on occasion can experience shortages or temporary unavailability of personnel and in those instances rely on outside personnel. The commenter suggests that such outside personnel can be as knowledgeable of and familiar with design and operations as in-house employees. The commenter believes that company-hired contractors or consultants should also be allowed to sign off on certifications if they have appropriate expertise, (e.g., if they have designed the system in question). The commenter contends that this would provide additional flexibility without sacrificing any environmental protections because such third parties would have to have appropriate expertise on design and operation of the system in order to complete a certification or to make a required technical determination.

Response II-8-26: The final rule requirements for pumps have been revised from the December 2022 Supplemental Proposal. The EPA determined it was possible to specify the conditions under which the different pump requirements apply in the NSPS and EG that reflect the BSER and that eliminate the need for demonstrations of technical infeasibility. The analyses for BSER show there are technically feasible zero-emission options, which can be implemented at costs the EPA considers reasonable at sites with access to electricity and at sites without electricity that have three or more natural gas-driven diaphragm pumps. Routing emissions to a process is

included as a zero-emissions option, as the EPA recognizes that with proper equipment operation, this option will result in zero emissions from pumps. Sites without electricity and with fewer than three natural gas-driven diaphragm pumps may use zero emissions options or may reduce emissions using existing control devices. At these sites, if a VRU is not onsite to route emissions through to a process, or if no emissions control device is onsite, pump emissions are not required to be reduced. These requirements reflect the BSER determinations regarding emissions reductions, costs, and other impacts.

Comment: Commenter (2326-AXPC) states that existing well sites, centralized production facilities, or compressor stations may not have adequate surface space for the proper placement of instrument air control systems – *e.g.*, due to safety and other permitting constraints. Where this is the case, the commenter provides that it would be technically infeasible to utilize a pneumatic pump not driven by natural gas. Accordingly, the commenter requests that EPA clarify in the final rule text that spacing constraints may pose technical infeasibility.

Response II-8-27: The technical infeasibility provisions of the final rule are limited to sites with fewer than three natural gas-driven diaphragm pumps, do not have access to electrical power, and that are trying to use existing control equipment or devices to reduce pump emissions. These provisions are intended to account for situations where it is technically infeasible for the existing equipment to handle pump emissions, which the equipment was likely not designed for. For other sites, considering the small footprint of the equipment necessary to power pumps, it is unlikely that space for the equipment will be an issue. However, the EPA notes that there are several options besides instrument air systems that are available to owners/operators for compliance with the rule if space is a constraint for such a system.

Comment: Commenter (2428-API) states that one of the legal flaws in EPA’s technical infeasibility opt-out scheme is that technical feasibility is the only governing criterion. The commenter provides that the cost of implementing the default zero-emitting standard is not a consideration. As a result, the commenter asserts that the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA section 111 standards of performance. The commenter suggests that this flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Response II-8-28: The final rule requirements for pumps have been revised from the December 2022 Supplemental Proposal. The EPA determined it was possible to specify the conditions under which the different pump requirements apply in the NSPS and EG that reflect the BSER and that eliminate the need for demonstrations of technical infeasibility. The BSER determinations included consideration of technical feasibility, emissions reduction potential, costs, and other impacts of emissions controls. The technical infeasibility provisions of the final rule are limited to those sites without access to electrical power, with fewer than three natural gas-driven diaphragm pumps, and that are trying to use existing control equipment or devices to reduce pump emissions. While control equipment can often accept additional emissions streams routed to them, existing equipment not already handling pump emissions would likely not have been designed with these emissions in mind. These provisions are intended to provide only for situations in which it is technically infeasible for the existing equipment to handle pump emissions.

### 8.3 NSPS OOOOb BSER Analysis/Emissions/Costs

Comment: Commenter (2446-Independent Petroleum Association of America (IPAA)) notes that the EPA acknowledges that historical GHG inventories, including those from the 2021 Greenhouse Gas Inventory (GHGI) for 2019 emissions, are significantly overstated. The commenter states that emissions are overstated by approximately 35 percent at least and over 90 percent or more at most for intermittent-bleed pneumatic devices, which represent a majority of the pneumatic devices in operation within the petroleum and natural gas system segments today. As such, the commenter states that a 5 percent difference in emissions reduction by allowing the use of existing or new control devices is hardly a "significant increase" and they believe should be an acceptable alternative BSER.

Response II-8-29: As explained in response II-8-22, the NSPS and EG reflect the EPA's BSER determinations. For sites with electricity and for sites without electricity and three or more natural gas-driven diaphragm pumps, the EPA concluded that zero-emissions represented the BSER, and the NSPS and EG reflect this determination by requiring zero emissions from pumps at these sites. For sites without electricity and fewer than three natural gas-driven diaphragm pumps, the EPA determined that the BSER for these sites is the use of existing equipment to route emissions to a process or to a control device. The NSPS and EG reflect this determination by requiring emissions from pumps at these sites to be routed to a process or control device, if a VRU or control device is onsite.

Comment: Commenter (2283-Endeavor) estimates that it would cost about \$85,500 per well site to convert pneumatic equipment to instrument air. If multiplied across just the commenter's approximately 2,000 existing well sites likely subject to EPA's proposed requirements, the cost would be astronomical. When all existing well sites across the industry are considered, the costs cannot be justified and are likely to significantly increase the prices that consumers pay for gas. According to the commenter, the complete retrofit of a low-producing facility with pneumatic equipment is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production. While EPA should revisit whether to include such requirements in its proposed EGs at all, the commenter believes that the EPA should at the very least exempt low-producing wells from the pneumatic equipment requirements to ensure the rule properly considers costs and remaining useful end of life as required by the CAA. If EPA does include any such requirements in its final rules, the commenter believes it must revise its economic analysis to reflect these higher costs.

The commenter (2283-Endeavor) adds that the incorporation of intermittent renewable power sources into operations may not be practicable. The commenter estimates that for its existing well sites, solar panels, and batteries necessary to power the site 24 hours per day would cost approximately \$140,000 per well site. Further, this equipment would likely require at least 300 square feet of space—a significant concern considering the limited footprint of many well sites and one which would also necessitate additional land disturbances and impacts to the local environment. Beyond costs figures, the commenter reports that large-scale solar applications have not been sufficiently tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight. And solar generation systems with on-site battery storage raise



additional concerns regarding supply chain constraints (*e.g.*, availability of rare earth metals) and environmental concerns (*e.g.*, battery end-of-life disposal).

Commenter (2202-TXOGA) states that throughout the December 2022 supplemental proposal, technical feasibility is discussed in its relation to what compliance options are available depending on the source.<sup>10</sup> The proposal solicits comment regarding pneumatic pumps, and it appears to imply that technical viability is related to cost:

Instrument air systems can also be utilized at sites without access to the electricity grid, but these would require the installation and operation of a generator. These generators could be powered by engines fueled by solar energy, natural gas, or diesel. [...] While this is a technically viable option at these remote sites, we did not have detailed cost information available to include these systems in our analysis.

[...] The EPA is specifically requesting more detailed information on the use of generators at sites without access to the grid to power pneumatic controllers, primarily to power instrument air systems. The EPA is also interested in receiving more information on the costs associated with this equipment.<sup>11</sup>

The commenter (2202-TXOGA) expresses that they do not believe it was EPA's intent to link technical feasibility to cost.

Response II-8-30: The EPA's determination of BSER considers the emissions reduction methods that have been demonstrated, along with their efficacy, costs, and other impacts. In the analyses conducted for the BSER determination for pumps, the EPA included estimates of the costs of the systems that would be used for the affected equipment, which is the natural gas-driven pumps at the site, but not all equipment at the site. Where there are more pumps to be controlled, the costs of the system may be higher, but greater emissions reductions will also result from the control system. The EPA determined the BSER considering both the emissions reductions and the impacts, including the associated costs. The BSER determinations are reflected in the requirements of the NSPS and EG.

Comment: Commenter (2220-WDEQ) suggests that, for smaller operators who only have one or two pneumatic pumps on a site, performing process re-routing or putting on emissions controls may not be cost-effective.

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<sup>10</sup> See 87 Fed. Reg. at 74,819 (Similarly, in making the BSER determination, the EPA must evaluate whether a system of emission reduction is "adequately demonstrated" for the source category based on the physical possibility and technical feasibility of control.); see also 87 Fed. Reg. at 74,820 (The EPA proposes in EG OOOOc to require that, in order to demonstrate that a designated facility cannot reasonably meet the presumptive level of stringency based on one of these three criteria, the state must show that implementing the BSER is not reasonable for the designated facility due to fundamental differences between the factors the EPA considered in determining the BSER, such as cost and technical feasibility of control, and circumstances at the designated facility.").

<sup>11</sup> EPA Issues Supplemental Proposal to Reduce Methane and Other Harmful Pollution from Oil and Natural Gas Operations, EPA's Supplemental Proposal for Oil and Natural Gas Operations - Comment Solicitation Spreadsheet, available at [https://www.epa.gov/system/files/documents/2022-11/MEMO\\_Supplemental%20Rule\\_Comment%20Solicitations\\_October%202022%20%281%29.pdf](https://www.epa.gov/system/files/documents/2022-11/MEMO_Supplemental%20Rule_Comment%20Solicitations_October%202022%20%281%29.pdf).

Response II-8-31: In determining the BSER, the EPA conducted analyses of the potential emissions reductions, costs of emissions control, and other impacts associated with various pump emissions control strategies. The EPA found that for sites without access to electrical power and with only one or two natural gas-driven diaphragm pumps, the costs are reasonable, considering the emissions reductions that would be achieved, for the affected pumps at the site to be routed to a process through an existing VRU or to an existing control device. The EPA found that the costs for routing emissions through a new VRU to a process or to a new control device at these sites would not be reasonable, considering the emissions reductions that would be achieved. The EPA determined that the BSER for these sites is to use a VRU already onsite to route emissions to a process or to route emissions to an already onsite control device. The NSPS and EG reflect this BSER finding.

Comment: Commenter (2399-GPA Midstream Association) requests that EPA include the cost of a vapor recovery unit (VRU), because a pneumatic pump requires a VRU to capture and route emissions. The statement in the Technical Support Document (TSD) misunderstands the purpose of a VRU at an oil and gas facility, including facilities in the midstream sector. The commenter explains that a VRU captures low pressure vapors (atmospheric, in the case of pneumatic pump emissions) and increases the pressure so that the vapor stream can be routed into the sales or process stream. It is not used to change gas composition, as the TSD suggests. Aside from the need to include the cost of installing and maintaining a VRU, the commenter states that the TSD underestimates other costs. For instance, the commenter's member companies' engineers when surveyed estimate that the costs for routing pneumatic pumps to an existing control device range from \$150,000 to \$300,000. The commenter states that this is far more than the \$6,102 EPA estimated in Tables 4-7 and 4-10 of the TSD based on oil and gas production well costs. Using the estimated lowest capital costs (\$150,000) for gathering and boosting compressor stations, the commenter states that the cost effectiveness numbers are significantly different than what EPA has estimated for this rulemaking.

Response II-8-32: In our revised analyses of control options for pumps, we considered the costs of a VRU for pump emissions to be routed to a process. The results of the analysis for this control option show that the costs of routing emissions to a process through a new VRU are reasonable for sites with access to electrical power and can use electricity from the grid to power the VRU. For sites without access to electrical power and fewer than three natural gas-driven diaphragm pumps, a generator would likely be needed to power the VRU, and the costs of routing emissions to a process would include the costs of both a new VRU and a new generator. The EPA determined that the costs associated with this equipment are not reasonable considering the emissions reductions that would be realized from the affected pumps at these sites.

Regarding the costs of routing emissions through a closed vent system to a process, the cost value used in our analyses includes information provided by commenters on the 2015 NSPS proposal. We note that the estimate of \$6,102 is the cost to route each pump, so a site with many pumps could have higher overall costs for routing all affected pumps to a process. In this instance, there would also be many pumps that have emissions reduced to zero, such that the costs of the closed vent system used to route the emissions to a process are reasonable considering the emissions reductions that would be realized.

Comment: Commenter (2446-IPAA) states that based on EPA's projected cost estimates, retrofitting a "medium model plant" would require an initial total capital investment (TCI) in the range of \$57,661,500 to \$180,000,000 to reduce 887 megatonne (mt) of methane emissions per year. Using the EPA's total annual cost (TAC) projections and a 15-year equipment life span, the cost per ton of methane reduced would be in the range of \$4,681 to \$23,819, which is well outside of EPA's reasonableness threshold of \$1,970/ton of methane reduced.

The commenter (2446-IPAA) adds that the EPA largely utilized historical data from its GHGRP as the basis for policy development, such as the requirements in NSPS OOOOb and EG OOOOc, which will require the oil and gas industry, amongst other things, to transition to zero-emitting pneumatic devices as the BSER. The commenter recommends replacing "one-size fits all" BSER for pneumatic pumps with the following alternatives:

*NSPS OOOOb:*

- Require pumps to be zero-emitting, consistent with current proposed BSER, if the BSER is determined to be "reasonable" based on a cost-effectiveness analysis performed by the operator of affected facilities. Reasonableness threshold of \$1970/ton methane emissions reduced or less; or
- If zero-emitting BSER is determined to be unreasonable/not cost effective, emissions must be routed to a control device with a destruction efficiency of at least 95 percent. All existing and proposed requirements for destruction devices would apply.

*EG OOOOc:*

- Require to be managed as part of proposed fugitive emissions requirements in EG Subpart OOOOc, including leak detection surveys, timely repairs, verifications, etc.; or
- Emissions routed to a control device with a destruction efficiency of at least 95 percent. All existing and proposed requirements for destruction devices would apply; or
- Zero-emitting, consistent with current proposed BSER.

Commenter (2294-Ohio Oil & Gas Association) states routing to process is unreasonable from a cost-effectiveness perspective. The commenter refers to Independent Petroleum Association of America (IPAA) and American Petroleum Institute (API) comment letter calculations.

Response II-8-33: The EPA has updated its BSER analysis to include more recent cost information for emissions control technologies as well as updated emissions factors now used for the Greenhouse Gas Reporting Program. Based on this analysis, the EPA finds that there are technically feasible emissions reduction options that are implementable at costs that are reasonable, considering the emissions reductions that would be achieved. The final standards reflect the BSER findings, which differ depending on site conditions. For sites with access to electrical power and sites that have three or more natural gas-driven diaphragm pumps, zero emissions from pumps is required. For sites without access to electrical power that have fewer than three diaphragm pumps (two or one), the standards require that GHG and VOC emissions

from all natural gas-driven pumps in the affected facility be routed to a process if a VRU is onsite. If a VRU is not onsite, emissions must be reduced by 95 percent if a control device with at least this emissions reduction capability is already available onsite or be reduced by less than 95 percent if a control device is onsite but is not capable of reducing GHG and VOC emissions by 95 percent or more.

Comment: Commenter (2428-API) states that the EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers,<sup>12</sup> EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012.

Response II-8-34: The EPA acknowledges that the analysis for the 2022 supplemental proposal relied on older information. In the analyses for the supplemental proposal, updated costs from previous analyses were included for pumps to reflect changes in prices due to inflation. However, these cost updates do not necessarily reflect changes that have occurred in the production of alternative technologies to the standard natural gas-driven equipment, such as the drop in costs for solar panels and batteries. Therefore, the EPA updated its analysis for pumps to use the more recent information for non-natural gas-driven pump options. This included information from the Carbon Limits reports, which addressed pump options as well as controllers.

Comment: Commenter (2433-EDF *et al.*) states EPA's analysis shows that zero-emitting pneumatic pumps are cost-effective across all segments. The commenter notes that the EPA's cost analysis for pneumatic pumps remained largely unchanged between its 2021 and 2022 proposals. The adjustments EPA made have rendered the analysis more robust and further supports the cost-effectiveness of conversion to zero-emitting pumps. Notably, the commenter provides that the EPA's analysis now shows that conversion to electric pumps (either with access to grid electricity or solar-powered) or instrument air pumps is cost-effective, even if only a single diaphragm or piston pump is located at the site. And costs decrease as the number of pumps increase. The commenter recommends, however, that EPA further improve its cost analysis by considering whether controllers exist on-site. EPA's cost analysis noted that pneumatic pumps and controllers often use the same equipment. The commenter believes that its cost analysis should reflect that reality. The commenter states that such a change would result in increased cost-effectiveness for a zero-emission pneumatic pump standard. For example, they add that although EPA's analysis demonstrates cost-effectiveness, as EPA notes it is still likely underestimating costs as it does not account for the fact that certain sources, like compressed air systems and control devices, can be used for both controllers and pumps.

Response II-8-35: The EPA acknowledges that some sites may use common equipment for the control of emissions from both pumps and process controllers, such as a compressed air system. However, sites may also use a different compliance method for these types of equipment, such as using solar-powered electric pumps but a compressed air system for its controllers. As it is not necessary for sites to choose the same method of compliance for both equipment types, the EPA

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<sup>12</sup> Carbon Limits. Zero Emission Technologies for Pneumatic Controllers in the USA. Applicability and Cost Effectiveness. August 1, 2016. and Carbon Limits. Zero Emission Technologies for Pneumatic Controllers in the USA. Updated Applicability and Cost Effectiveness. November 2021.

determined that it would not be reasonable to assess the BSER on the basis of both equipment types together. However, the EPA notes that even when assessed individually, the analyses show that there are zero-emissions options that are cost-effective for most sites.

## 8.4 Applicability and Compliance Date Considerations

Comment: Commenter (2428-API) notes that the EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. However, the regulatory text was not included in the *Federal Register* for neither the December 2022 proposal nor the November 2021 preamble description of requirements. As a result, the commenter states that it is unclear what date these provisions should be based. The commenter believes this should be based on the December 2022 proposal.

Commenter (2428-API) states the applicability date for pneumatic pumps under NSPS OOOOb should be the date of the publication of the December 2022 supplemental proposal. The commenter notes that, as the EPA acknowledges, the December 2022 proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps.

Response II-8-36: The applicability date for pumps under NSPS OOOOb is the date of publication of the December 2022 supplemental proposal, December 6, 2022.

Comment: Commenter (2326-AXPC) requests that the EPA extend implementation timelines – particularly for sources that became NSPS OOOOb affected facilities prior to the date of final rule publication. Until the effective date of NSPS OOOOb, some of these facilities would be unregulated under an existing NSPS or would begin operating as NSPS OOOOa affected facilities and may then need to complete retrofits to comply with newly applicable NSPS OOOOb standards. For example, the commenter states that NSPS OOOOa pneumatic pumps are not subject to a zero emissions standard but would be subject to zero emissions standards under NSPS OOOOb, requiring retrofit within 60 days of the final rule’s publication in the *Federal Register*. According to the commenter, this is not enough time to acquire retrofit equipment that will be in high demand, and likely short supply, as operators across the country place orders for equipment to meet the zero emissions standard. In addition, the commenter reports that operators must acquire engineering resources to engineer the installation of zero emissions pneumatic systems. They report that these engineering resources, too, are likely to be in high demand and short supply. The commenter asserts that the timing of compliance obligations is particularly pronounced for pneumatic pumps. For this equipment, EPA now proposes that operators may no longer utilize pneumatic pumps that are driven by natural gas, subject to limited exceptions. The commenter notes that the November 2021 proposal did not go so far as to eliminate the use of natural gas-driven pneumatic pumps entirely. This means operators may need to completely replace natural gas-driven pneumatic pumps that would have complied with the standards described in November 2021 proposal.

The commenter (2326-AXPC) proposes that EPA extend the initial compliance deadline for pneumatic controllers, pneumatic pumps, and storage vessels at least one year for those affected facilities that became NSPS OOOOb affected facilities between the “new” trigger date and the date the final rule is published in the *Federal Register*. Alternatively, if EPA is unwilling to

provide extended initial compliance deadlines, the commenter requests that EPA provide extensions where good cause exists, as it did under the recently promulgated Uintah and Ouray Indian Reservation Federal Implementation Plan (FIP) for oil and natural gas sources.

Response II-8-37: Based on these comments and supplemental information submitted by one commenter providing information regarding current equipment lead time and market conditions, it appears that some equipment necessary for the installation of zero-emitting pumps may not be available to enable new facilities or those that have started up or were modified or reconstructed since December 6, 2022, to comply with the zero-emissions pumps requirements within 60 days of the publication of the final NSPS.<sup>13</sup> According to this information, some of the operators surveyed report that they are experiencing delays in the availability of pumps, electrical transformers, generator skids, and compressor skids of up to 12 months.

Considering that the equipment types discussed in the information provided by these commenters are essential to the institution of zero-emitting pumps at a site and the estimated timeframes for the availability of equipment, the EPA is providing a compliance extension of one year for the zero-emissions pump requirements. Until the date of compliance of the zero-emissions requirements for pumps, owner/operators must be in compliance with the requirements for sites with fewer than three natural gas-driven diaphragm pump that do not have access to electrical power. The standards for these sites require that GHG and VOC emissions from all natural gas-driven pumps in the affected facility be routed to a process if a VRU is onsite. If a VRU is not onsite, emissions must be reduced by 95 percent if a control device with at least this emissions reduction capability is already available onsite or be reduced by less than 95 percent if a control device is onsite but is not capable of reducing GHG and VOC emissions by 95 percent or more. As these requirements are largely the same as the current NSPS OOOOa requirements for pumps at well sites, owners/operators of new and recently modified or reconstructed sites would already be routing emissions to a process or control device (if they have not installed zero-emitting pumps). The only difference is that NSPS OOOOb requires emissions to be routed to a process if a VRU is onsite before routing emissions to a control device would be allowed as a compliance method. Although the EPA expects this to be a rare circumstance, in some cases, it may be possible that pumps currently routed to a control device would be required to re-route those emissions to an onsite VRU to comply with these requirements. The information available to the EPA and provided by commenters does not suggest any equipment backlogs for additional common piping that may be needed to re-route emissions from a control device to a process through a VRU. Therefore, the EPA expects sites to be able to comply with these interim requirements within 60 days of publication of the final rule.

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<sup>13</sup> API. Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule.

## 8.5 Miscellaneous Other Comments

### 8.5.1 Recommended Regulatory Text Changes

Comment: Commenter (2177-Southern Ute) points out that 40 CFR 60.5420c(d) is mistakenly included in paragraph 40 CFR 60.5420c(c)(14)(x) and should instead be formatted as its own paragraph [return needed].

Response II-8-38: We have revised the formatting of the paragraph formerly numbered as §60.5420c(c)(14)(x) and now numbered as §60.5420c(c)(14)(viii) to correct the missing separation between it and paragraph §60.5420c(d).

Comment: Commenter (2428-API) suggests that the following citation be checked for correct cross-referencing: 40 CFR 60.5420b(b)(10)(vi).

Response II-8-39: After review, we have found that the December 2022 Supplemental Proposal paragraph §60.5420b(b)(10)(vi) had an incorrect cross-reference to another paragraph in the proposed rule. For the final rule, we have revised and reorganized the regulatory text of §60.5420b(b)(10) such that paragraph §60.5420b(b)(10)(vi) no longer contains the same content that was included in that paragraph at proposal. We have ensured that this incorrect cross-reference is no longer in any paragraph of the final regulatory text.

### 8.5.2 Certifications

Comment: Commenter (2227-WEA) states that to the extent an engineer will be held responsible for a certification and be subject to potential civil and criminal penalties, it should be limited to fraudulent activity. The commenter believes it should not be related to unintentional errors or oversight that may have resulted in a flaw in the assessment. According to the commenter, these sorts of certifications will necessarily include a mix of objective and more subjective criteria, and engineers should be granted the deference to make determinations within their best professional knowledge and experience. The commenter recommends limiting subjecting an engineer's certifications liability and subjecting them to civil and criminal penalties to scenarios that involve fraudulent activity and not include unintentional errors or oversight.

Commenter (2428-API) states EPA should remove the additional certifications associated with the hierarchy (routing emissions to process being at a lower tier than that of implementing instrument air systems using solar or natural gas). The commenter provides that the CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals, or fails to file or maintain a document filed or required to be maintained under the CAA.

The commenter (2428-API) also notes the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches are “technically infeasible.” The commenter states that there is no definition of technical infeasibility in the proposed rules, but the words

could be construed as setting an exceedingly high bar, such that a given non-emitting technique is “infeasible” based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. For example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. According to the commenter, this outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, the commenter (2428-API) believes that a “technical infeasibility” standard allows for second guessing by regulators or citizen enforcers, which invites a “battle of the experts” in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the commenter (2428-API) reports that the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly considering the uncertainties described above about what will be needed as a practical matter to demonstrate “technical infeasibility.” The commenter states that the clear opportunity and possibility of second guessing will be further material disincentives.

If EPA retains the requirement for case-specific certifications, the commenter (2428-API) recommends that EPA revise the required certification. The proposed regulatory text of each certification includes the following sentence:

Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. [See, e.g., 40 CFR 60.5377b(b)(2).]

The commenter (2428-API) suggests that this should be revised to specify that the certification is based on “reasonable inquiry,” as is required for certifications under the Title V operating permit program. The commenter suggested the following revised certification language in lieu of the above language:

Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, ....

The commenter (2428-API) provides that a “reasonable inquiry” standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

Response II-8-40: In consideration of these comments, the EPA reviewed the proposed certification of infeasibility requirements. The EPA augmented the structure of the final standards for pumps based on comments received on the December 2022 Supplemental Proposal and determined that they could be revised to include the criteria for which certain emissions standards would apply without requiring the need for demonstrations of technical infeasibility. We have revised the proposed rule to incorporate the conditions that reflect our BSER determinations, which incorporate our understanding of technical feasibility, emissions



reductions, costs, and other impacts. The final rule now clarifies which emissions standards for pumps must be met based on the site conditions and does not require demonstrations of infeasibility.

Comment: Commenter (2221-Texas Pipeline Association) states the rules should allow in-house engineers, and non-PE outside personnel, to make required certifications and determinations. The commenter also states EPA should expand the universe of persons who could make required certifications and determinations to include non-PE outside personnel. Companies on occasion can experience shortages or temporary unavailability of personnel and in those instances rely on outside personnel. Such outside personnel can be as knowledgeable of and familiar with design and operations as in-house employees. Company-hired contractors or consultants should also be allowed to sign off on certifications if they have appropriate expertise, *e.g.*, if they have designed the system in question. According to the commenter, this would provide additional flexibility without sacrificing any environmental protections because such third parties would have to have appropriate expertise on design and operation of the system to complete a certification or to make a required technical determination.

Response II-8-41: The final rule now clarifies which emissions standards for pumps must be met based on the site conditions and does not require demonstrations of the infeasibility of the use of non-natural gas-driven pumps. However, for sites without access to electrical power and that have fewer than three natural gas-driven diaphragm pumps, owners/operators may demonstrate that it is technically infeasible to use existing equipment to control pump emissions. These demonstrations may be conducted by a qualified professional engineer or an in-house engineer. The EPA has not expanded the universe of persons permitted to make these demonstrations since owners/operators of this small subset of sites should be able to obtain the necessary in-house or hired contractors with these qualifications to perform these demonstrations.8.5.3 Interaction of the Pneumatic Pump Proposed Standards with Pneumatic Controller Proposed Standards

Comment: Commenters (2028-Westmoreland Marcellus Citizens' Group, 2039-Citizens to Preserve Ligonier Valley, Inc.) state that the requirement for air driven zero emitting pneumatic devices on controllers should be expanded to include pneumatic pumps.

Response II-8-42: For the final rule, the EPA has revised the NSPS and EG requirements for pumps to allow any zero-emitting option to be used at sites with access to electrical power and at sites without access to electrical power that have three or more natural gas-driven diaphragm pumps. One option available to owners/operators in achieving zero emissions from pumps is the use of pneumatic pumps driven by compressed air. For sites without access to electricity and with fewer than three natural gas-driven pumps, owner/operators may choose to employ a zero-emitting option for pumps or they may use a control device already onsite to reduce emissions. If no VRU is onsite for routing emissions through to a process or no control device is onsite, pump emissions at these sites are not required to be reduced.

Comment: Commenter (2428-API) has concerns regarding the practical and logistical aspects of how EPA has outlined control standards between the controllers and pumps. The commenter notes that the EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting

statements made to justify EPA's decisions. The commenter requests that the requirements for both pneumatic controllers and pumps be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device.

Commenter (2433-EDF *et al.*) urges EPA to mirror the proposed pump standard with the proposed controller standard by including routed pumps as a compliance option and eliminating the tiered feasibility exemption at sites without electricity.

Response II-8-43: In consideration of these comments, the EPA reviewed the proposed certification of infeasibility requirements. The EPA augmented the structure of the final standards for pumps based on comments received on the December 2022 Supplemental Proposal and determined that they could be revised to include the criteria for which certain emissions standards would apply without requiring the need for demonstrations of technical infeasibility. We have revised the proposed rule to incorporate the conditions that reflect our BSER determinations, which incorporate our understanding of technical feasibility, emissions reductions, costs, and other impacts. The final rule now clarifies which emissions standards for pumps must be met based on the site conditions and does not require demonstrations of infeasibility. In addition, we also have restructured the requirements to be technology-neutral. Further, as routing pump emissions to a process results in zero emissions from the pumps, the EPA allows this as a zero-emissions compliance option and does not require that non-natural gas-driven pumps be used to meet the zero-emissions requirements.

## **Chapter 9. Inflation Reduction Act (IRA) and Methane Emissions and Waste Reduction Incentive Program (MERP)**

Chapter 9 Response: In the preamble to the December 2022 Supplemental Proposal, the EPA noted that implementation of CAA section 136 was outside the scope of the supplemental proposed rule, and that the EPA intended to take one or more separate actions to implement CAA section 136. The EPA requested comment on the criteria and approaches that the Administrator should consider in making the CAA section 136(f)(6)(A)(ii) “equivalency determination.” Consistent with our statements in the December 2022 Supplemental Proposal, these comments are outside the scope of this final rule. Summaries of comments received on these issues are provided below for reference, but substantive responses are not provided.

### **9.1 Administrator’s Equivalency Determination**

#### ***9.1.1 Temporal Elements of the IRA and MERP***

##### **9.1.1.1 Time Period for the Determination**

Comment: Commenter (2433-Environmental Defense Fund (EDF) *et al.*) states that EPA should require that equivalent reductions be achieved in each year that the CAA section 136(f)(6)(A) exemption may be in effect as well as in the aggregate across a multi-year period through 2035, as analyzed in the November 2021 Proposal. First, the commenter asserts that the equivalency determination must apply in each year that any exemption from the waste charge is available. By way of example, the commenter explains that if final standards and plans have been approved, are in effect, and have been fully implemented in all states in 2028, EPA should evaluate whether those standards and plans will achieve equivalent or greater reductions to what the November 2021 Proposal would have achieved in 2028 if it had been fully implemented. Evaluating equivalency on a year-by-year basis is necessary to account for the fact that final CAA section 111 standards and plans may take effect on different timelines than projected in the November 2021 Proposal, states the commenter.

Second, the commenter (2433-EDF *et al.*) states that the equivalency must apply over the multi-year period through 2035 evaluated in the November 2021 Proposal. The commenter explains that Congress was aware of the estimated impact of the November 2021 Proposal’s presumptive standards and incorporated an expectation of equivalent effectiveness into CAA section 136(f)(6)(A)(ii)<sup>1</sup>. Final standards and plans should therefore be compared to this timeline and deliver equivalent or greater reductions in the multi-year period through 2035, in addition to equivalent or greater reductions in each year that they are fully in effect and implemented, states the commenter. The commenter believes this will help ensure that final standards and plans will achieve equivalency to the November 2021 Proposal, even if those final standards and plans are implemented on a later timeline.

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<sup>1</sup> See Greg Dotson and Dustin Maghamfar, The Clean Air Act Amendments of 2022: Clean Air, Climate Change, and the Inflation Reduction Act, 53 Env’t L. Reporter 10017, 10032 (Jan. 2023), <https://www.eli.org/sites/default/files/files-pdf/53.10017.pdf>.

Comment: Commenter (2326-American Exploration and Production Council (AXPC)) suggests that it may be possible that states could submit plans pursuant to CAA section 111(d) in a phased fashion (as long as each plan is submitted prior to the deadline). The commenter believes that if the states have adopted plans that implement emission guidelines (EG) OOOOc in part, then the exemption should apply for those sources covered by the state plans that have been adopted. The commenter states that such phasing could allow states to begin implementing the requirements from EG OOOOc faster, which would reduce emissions faster. According to the commenter, if the MERP exemption eligibility were deferred until a state has adopted all provisions of the state plan, that would disincentivize expeditious adoption of provisions with respect to many of the most prominent emissions sources, delaying reductions and resulting in considerable foregone emissions reductions.

Comment: Commenters (2283-Endeavor Energy Resources, L.P. (Endeavor), 2301-U.S. Chamber of Commerce (USCC)) encourage EPA to evaluate equivalence based on a multi-year evaluation of emission reductions (for requirements phased in over a multi-year period), rather than, as EPA proposes to do, considering emission reductions only upon full implementation of phased-in requirements (i.e., if a state phases in installation of zero-emitting pneumatic controllers over more than one year, the comparison should be made at the point that the EGs require full use of zero-emitting controllers). The commenter (2301-USCC) believes that EPA's proposed approach is inappropriately rigid and would ignore real world emissions reductions.

Conversely, commenter (2410-California Office of the Attorney General (CA AG) *et al.*) agrees with EPA that the appropriate comparison should be based on when the new source performance standards (NSPS) or state plan requirements are fully implemented by the sources. The commenter states that such an interpretation is consistent with the prefatory language in CAA section 136(f)(6)(A), which provides that a methane charge will not be imposed only when an affected facility is "subject to and in compliance with" methane standards under CAA section 111(b) or (d). The commenter states it is also consistent with CAA section 136(f)(6)(A)(i), which requires the standards and plans to have been approved and be in effect before the methane charge will no longer be imposed.

#### 9.1.1.2 Timing of the Determination for New Sources

Comment: Commenters (2326-AXPC, 2399-GPA Midstream Association (GPA)) state that new source eligibility for the exemption should not be tied to the status of implementation of existing source regulations. Commenter (2326-AXPC) states that EPA has significant latitude to interpret the scope of the exemption for regulatory compliance, due to the ambiguous language of the IRA and lack of legislative history. The commenter urges EPA to frame the determination by the overarching goal of reducing emissions which the commenter believes is the objective policy outcome in keeping with the title of this section of the IRA. For NSPS OOOOb, the commenter states the determination can be made when the regulation goes into effect and EPA could determine that all such sources subject to NSPS OOOOb are meeting the requirements under 42 U.S.C. Ch. 85 section 7436(f)(6)(A) (and exempt emissions associated with such sources from the methane fee).

Commenter (2326-AXPC) states that assuming that the final rule is “equivalent” to the November 2021 Proposal within the meaning of the IRA, the EPA Administrator should make the determination of this equivalency with respect to new sources at the same time of the final rule or before reporting and recordkeeping requirements go into effect, whichever is earlier. Further, the commenter states, this provision can only be reasonably interpreted such that the determination of whether new source standards “are in effect” should be made separately from any determination of whether existing source standards “have been approved and are in effect.” The commenter contends that it would be unreasonable to tie new-source eligibility for the exemption to the status of existing-source regulation. The commenter believes that Congress’s goal in the MERP is to ensure emissions reductions in keeping with the text and structure of CAA section 111, and the MERP provision should be read in harmony with that (in keeping with the fundamental axiom that all statutory provisions are to be read in harmony with one another to the greatest extent possible).

Commenter (2399-GPA) states that for purposes of determining that the waste emission charge exemption applies, EPA should use the NSPS OOOOb effective compliance date and make the necessary evaluation of equivalency at the time it issues a final rule. The commenter explains that this will ensure a reasonable application of the regulatory compliance exemption from the waste charge. The commenter believes there is no reason for a new source subject to CAA section 111(b) to wait for any state to choose to incorporate new source emission standards. As states are not obligated to adopt such standards for the standards to be “in effect” in a state<sup>2</sup> the commenter explains, such an interpretation could render the exemption a nullity, even if only temporarily, for those sources within states that delay or choose not to adopt their own new source standards. Likewise, the commenter states, it would be illogical to wait for a state to propose and implement a plan for existing sources that would not apply to the new source subject to CAA section 111(b) standards. The commenter warns that they believe that such an interpretation would accomplish the opposite of Congress’s intent in creating the exemption, by punishing complying facilities rather than incentivize continued compliance.

Comment: Commenters (2326-AXPC, 2410-CA AG *et al.*, 2433-EDF *et al.*) state that the IRA equivalency determination should be done once the standards of performance pursuant to CAA section 111(b) are fully promulgated. Commenter (2410-CA AG *et al.*) contends that this is consistent with the language at CAA section 136(f)(6)(A)(i) that standards “have been approved and are in effect.”

Commenter (2433-EDF *et al.*) states that the plain language of CAA section 136 indicates that EPA must evaluate final standards for equivalency. The commenter cites to CAA section 136(f)(6)(A)(i), which requires “methane emissions standards...pursuant to subsections (b)...of section 111 [to] have been approved and . . . in effect in all States.” In turn, the commenter explains, CAA section 136(f)(6)(A)(ii) requires EPA to determine that “compliance with the requirements described in clause (i)” will achieve equivalent reductions to the November 2021 proposed rule. The “requirements” for new sources evaluated for equivalency in section (ii) are referring to “emissions standards” that “have been approved” and are “in effect in all States” states the commenter.

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<sup>2</sup> See 42 U.S.C. section 7411(c).

Commenter (2326-AXPC) recommends that the date of the final NSPS OOOOb be deemed the approval date for sources regulated under NSPS OOOOb and the effective date be sixty days following EPA's final NSPS OOOOb. The commenter suggests that the provision at CAA section 136(f)(6)(A)(i) can only be reasonably interpreted such that the determination of whether new source standards "are in effect" is to be made separately from any determination of whether existing source standards "have been approved and are in effect." The commenter adds that it would be unreasonable to tie new source eligibility for the exemption to the status of existing source regulation. The commenter believes that Congress's goal in the MERP is to ensure emissions reductions in keeping with the text and structure of CAA section 111, and the MERP provision should be read in harmony with that CAA section 111 (in keeping with the fundamental axiom that all statutory provisions are to be read in harmony with one another to the greatest extent possible).

#### 9.1.1.3 Timing of the Determination for Existing Sources

Comment: Commenter (2399-GPA) states that EPA should adopt a reasonable interpretation of the IRA requirement for standards and plans to be in effect "with respect to" the applicable facilities. Accordingly, the commenter recommends that EPA allow sources that comply with the EG OOOOc, establishing the minimum "standards and plans" for the facility, to be able to show compliance and thereby establish coverage for the exemption. The commenter believes this would incentivize sources to comply early—even before a state goes through what can be an often long planning and adoption process. At a minimum the commenter recommends that EPA confirm that the reference to "all states" does not mean a facility must wait for other states to act. The commenter warns that waiting for each and every state to adopt an EPA-approved plan would otherwise unfairly restrict a facility's ability to utilize the exemption, contrary to what they believe was Congress' intent.

Comment: Commenters (2283-Endeavor, 2326-AXPC, 2410-CA AG *et al.*) recommend that EPA make an evaluation as soon as possible. Commenter (2326-AXPC) states that EPA has significant latitude to interpret the scope of the exemption for regulatory compliance, due to the ambiguous language of the IRA and lack of legislative history. The commenter urges EPA to frame the determination by the overarching goal of reducing emissions which the commenter believes is the objective policy outcome in keeping with the title of this section of the IRA. The commenter states that the most efficient approach would be for the Administrator to make determinations when each state adopts as a matter of state law a state plan pursuant to CAA section 111(d) and EG OOOOc as this will encourage states to move faster in development of their state plans and thus reduce emissions faster. The commenter explains that due to the difference in resources available across different state agencies, and to the unique nature and distribution of each state's fleet of existing sources, it is highly likely that states will submit their state plans at different times and that these state plans will feature different levels of detail, which will require varying and unpredictable devotion of EPA resources to plan review.

Furthermore, the commenter (2326-AXPC) expresses, it would not be reasonable to interpret the term "in all states" to require that all states have approved state plans (or promulgated federal plans) in order for the facilities in any one state to be eligible for the exemption. The commenter notes that if there are delays or other obstacles to approving state plans or promulgating federal

plans in one or a handful of states, Congress showed no sign that it wanted to penalize facilities in other states where a state or federal plan is in effect. Instead, the commenter believes that by using the phrase “in all states *with respect to the applicable facilities*” (emphasis added) Congress recognized that facilities may reside in multiple states. According to the commenter, the best, perhaps the only permissible, reading of this provision is that, for an existing source facility to qualify for the exemption, a state (or federal) plan must be in effect in all states within whose territory the facility extends.

By way of example, the commenter (2326-AXPC) provides the following scenario:

States A, B, and C with just midstream operations (*e.g.*, natural gas processing plants) adopt (as a matter of state law) state regulations or plans pursuant to EG OOOOc, and the adopted state regulations or plans have become legally effective as a matter of state law (irrespective of submission to and timing of EPA approval). At the same time, some states (States E, F and G) have not adopted (as a matter of state law) state regulations or plans.

- EPA can determine that midstream operations that are regulated under state regulations adopted as a matter of state law pursuant to EG OOOOc in States A, B, and C meet the requirements under CAA section 136(f)(6)(A) and are exempt from the methane fee.
- To the extent that an operator’s assets span multiple states, then the operator should be exempt from the methane fee for emissions associated with any assets in a state that has adopted (as a matter of state law) regulations that are in effect (*i.e.*, States A, B, and C above) pursuant to EG OOOOc.

Regarding federal plans, the commenter (2326-AXPC) states that it is reasonable for EPA to interpret the IRA’s language such that a federal plan being “in effect” in the state (or multiple states in the case of facilities extending across state lines) satisfies the prerequisite for the exemption at CAA section 136(f)(6)(A)(i). Conversely, the commenter adds that it would be unreasonable to interpret this language such that a federal plan will not satisfy this prerequisite. According to the commenter, the purpose of the MERP is to ensure emissions reductions and they believe there is no sign that Congress wished to disregard reductions effected by federal plans for existing sources.

Commenter (2283-Endeavor) suggests that the equivalency be done by assuming designated facilities would be subject to their corresponding EG presumptive standards once state plans are implemented, given that that the start date for the methane fee will come before fully approved state EG plans are in place. Commenter (2410-CA AG *et al.*) asserts that, consistent with the language in CAA section 136(f)(6)(A)(i), EPA should make the evaluation once the EPA has approved state plans and/or developed a Federal Plan (*i.e.*, plans “have been approved and are in effect.”)

Comment: Commenter (2433-EDF *et al.*) states that EPA should make the evaluation and equivalency determination once standards of performance pursuant to CAA sections 111(d) are fully promulgated nationwide by comparing the November 2021 Proposal to final, approved state plans (and any Federal Plan if applicable). The commenter adds that the plain language of

CAA section 136 indicates that EPA must evaluate final plans for equivalency. The commenter cites to CAA section 136(f)(6)(A)(i) which requires “methane emissions...plans pursuant to subsection...(d) of section 111 [to] have been approved and . . . in effect in all States.” In turn, the commenter provides that CAA section 136(f)(6)(A)(ii) requires EPA to determine that “compliance with the requirements described in clause (i)” will achieve equivalent reductions to the November 2021 Proposal. The “requirements” for existing sources, evaluated for equivalency in CAA section 136(f)(6)(A)(ii) are referring to “plans” that “have been approved” and are “in effect in all States.”

#### 9.1.1.4 Remaining Useful Life and Other Factors (RULOF)

Comment: Commenters (2326-AXPC, 2410-CA AG *et al.*, 2433-EDF *et al.*) provide comments on addressing RULOF. Commenter (2433-EDF *et al.*) states that because CAA section 136(f)(6)(A)(ii) directs EPA to determine that “compliance” with plans will achieve equivalent reductions to the November 2021 Proposal, EPA must consider how facilities will comply with final plans. This necessarily entails an evaluation of whether fully implemented state plans—including any less stringent standards adopted based on an invocation of RULOF—achieve equivalent reductions to the November 2021 Proposal, states the commenter. The commenter suggests that, because that proposal did not indicate if or how variances might have been approved, and instead only contained presumptive standards in the proposed EGs, EPA cannot hypothesize states’ invocation of RULOF under the November 2021 Proposal but must instead assume each state fully implemented the proposed November 2021 EGs when estimating reductions. The commenter believes this is consistent with EPA’s emissions reductions estimates in the regulatory analysis for the November 2021 Proposal, where the agency did not assume any variances and instead assumed that state plans would fully reflect the emission reductions projected under the proposed guidelines. Lastly, the commenter states that evaluating final, approved state plans for equivalency will both incentivize expeditious submission of state plans and disincentivize overbroad invocation of RULOF to justify less stringent standards in state plans.

Commenter (2410-CA AG *et al.*) states that with respect to RULOF, CAA section 136 does not by its terms compel any consideration of RULOF in making an IRA equivalency determination. Therefore, the commenter believes that it would be appropriate for EPA to conduct an equivalency evaluation with respect to an applicable facility without consideration of the application of these factors.

Commenter (2326-AXPC) states that the November 2021 Proposal did not provide much, if any, detail on how states can apply RULOF, but acknowledges that its application is within the authority of the CAA and the states. Therefore, the commenter states, the use of RULOF is inherent within the stringency of the November 2021 Proposal, even if EPA does not quantify or monetize those provisions.

Comment: Commenter (2442-Wyoming Coalition of Local Governments (WYCLG)) appreciates EPA’s questions regarding how the proposed supplemental rule and the waste emissions charge (WEC) will interact. However, the commenter is concerned with the fact that the IRA equivalence determination is based on emissions reductions under the November 15, 2021,



proposed rule, which has now been substantially amended by the December 2022 Supplemental Rule. Further, the commenter adds that, under the December 2022 Supplemental Rule, there is the ability for states to apply a less stringent standard to a designated facility, based on RULOF. The commenter is concerned that it is unclear how less stringent RULOF standards would affect the IRA equivalency determination, and whether adopting the less stringent standards would then subject facilities to the WEC. The commenter believes this would ultimately conflict with the purpose of adopting a less stringent RULOF standard, which is to help avoid unnecessary and unreasonable costs when a facility is aging and towards the end of its useful life.

#### 9.1.1.5 Other Related Comments Regarding Timing for Both New and Existing Sources

Comment: Commenters (2301-USCC, 2326-AXPC, 2409-BP America Incorporated (BP)) recommend that the determination be made as soon as possible. Commenter (2326-AXPC) states that even if the determination is made only for a subset of sources, the earliest determination will maintain the purpose of the MERP and minimize administrative burden, states the commenter. Commenter (2301-USCC) states that given that the methane fee will take effect in 2025, the commenter notes that it is critical that EPA make the equivalence determination as soon as practicable and should not wait for all states to submit their plans, as doing so would unduly delay the determination and force operators in states that already have “equivalent” programs to pay potentially significant fees. Further, the commenter states that given that the start date for the methane fee will come before fully approved state EG plans are in place, EPA should make an evaluation by assuming designated facilities would be subject to their corresponding EG presumptive standards once state plans are implemented.

Commenter (2409-BP) asserts that it is imperative not only for EPA to finalize the CAA section 111(b) and (d) rules in a timely manner, but also for EPA to put in place a process and timeline for reviewing and approving state plans as efficiently as possible to ensure that the WEC exemption is available to compliant facilities. In particular, the commenter recommends that EPA ensure that state plans submitted pursuant to the proposed EG OOOOc (after the 18-month period allotted for states to develop those plans) are approved and effective by 2025 at the latest, so that there will be only one year (*i.e.*, 2024) in which the IRA fee is applicable without any safe harbor for facilities actively complying with the CAA section 111(b) and (d) standards. In consideration of the aforementioned, the commenter supports EPA’s efforts to finalize the supplemental proposal and implement a process for the expeditious approval of state plans.

Comment: Commenters (2254-Permian Basin Petroleum Association (PBPA), 2283-Endeavor) provide comments on the criteria and approaches that EPA should use in making the equivalence determination. Commenter (2254-PBPA) states that EPA should not unnecessarily delay making an equivalency determination. Commenters (2254-PBPA, 2283-Endeavor) state that EPA should assume that designated facilities would be subject to their corresponding EG presumptive standards once state plans are implemented.

Comment: Commenter (2292-West Virginia Office of the Attorney General *et al.*) states that the December 2022 Supplemental Proposal openly refuses to engage with the complications that result from the interplay between the provisions in the proposed rule and the MERP. The commenter is concerned that this could produce still more costs for the energy industry. They

add that they are also concerned that EPA has not explained how it will make the equivalency determination; nor has it explained how it will address the time gap between implementation of any new standards and the start date for the fee program. The commenter notes that they shared similar concerns, that a methane fee is ill-advised, more than a year ago.<sup>3</sup> The commenters believe that Congress created the “safe harbor” (*i.e.*, if the source complies with methane standards that produce emission reductions that are equivalent to or greater than the reductions the Proposed Rule) from fees, to address these concerns. Yet the commenter believes that EPA seems willing to undermine the safe harbor’s usefulness by keeping standards for meeting it vague (*e.g.*, EPA has done only a “purely qualitative” comparison between reductions achieved by the December 2022 Supplemental Proposal and reductions that would have been achieved by the November 2021 Proposed Rule).

Comment: Commenter (2399-GPA) states that EPA should apply a common sense definition of “applicable facility” to harmonize the different requirements in the WEC.<sup>4</sup> The commenter recommends that EPA view a “facility” using the common sense notion of an operating site – not the equipment-level “affected facility” used in NSPS OOOOb/EG OOOOc, nor the basin-level “facility” used in Subpart W. They add that they believe throughput should similarly be based on discrete sites (*i.e.*, each gathering and boosting compressor station). According to the commenter, any other interpretation would result in arbitrary treatment among industry segments and would lead to significant uncertainty as operators attempt to parse out what exactly is and is not a “facility” and how to correctly assess facility throughput. The commenter recommends that to address this potential confusion, EPA should revise Subpart W throughput reporting elements for gathering and boosting to allow reporters to reflect true facility throughput.

If EPA utilizes existing regulatory definitions to define a “facility,” the commenter (2399-GPA) cautions that implementation of the IRA’s language will be particularly challenging in that the terms “facility” and “facilities” have vastly different meanings in Subpart W and NSPS OOOOb/EG OOOOc, and those meanings themselves do not necessarily align with the public’s understanding of what these words mean. The commenter explains that, in NSPS OOOOb/EG OOOOc, the “affected facility” is an individual piece of equipment (or group of equipment, like all the natural gas-driven pneumatic controllers at a gas plant), while on the opposite side of the spectrum, under Subpart W, a gathering and boosting “facility” includes all gathering and boosting emission sources within a basin, which is usually a large geographic area spanning many counties and sometimes many states. The commenter adds that neither the NSPS OOOOb/EG OOOOc nor the Subpart W gathering and boosting facilities definitions are consistent with a general understanding of the word “facility.” Accordingly, the commenter suggests that EPA use the simplest interpretation of the term, which is that “a facility” is a single site, and not specific pieces of equipment within that site, nor the aggregation of hundreds of sites within a geographic area. The commenter believes this approach is straightforward and “bridges the gap” between NSPS OOOOb/EG OOOOc and Subpart W.

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<sup>3</sup> See Letter from Patrick Morrissey, W. Va. Att’y Gen., et al. to Senate Leadership (Oct. 14, 2021), available at <https://bit.ly/3l4MKgS>.

<sup>4</sup> See Docket ID Nos. EPA-HQ-OAR-2022-0875, EPA-HQ-OAR-2022-0875-0002 (submitted January 18, 2023) (“GPA Midstream Comments to MERP Docket”). See Exhibit F.

### ***9.1.2 Geographical Elements of Administrator’s Equivalence Determination***

Comment: Commenter (2177-Southern Ute Indian Tribe (Southern Ute)) provides comment on EPA’s request regarding the geographical elements of the requirements in CAA section 136(f)(6)(A)(i). The commenter states that EPA should consider a basin or depositional environment consideration for different oil and gas fields, as each field has unique elements that make blanket regulations not applicable or overly stringent in cases of low volatile organic compound (VOC) carrying capacity.

Comment: Commenters (2254-PBPA, 2283-Endeavor, 2301-USCC) state that EPA’s evaluation should make this evaluation on both a national level and state-by-state level, and that a finding of equivalence under either approach should be sufficient to trigger the methane fee exemption.

Comment: Commenter (2410-CA AG *et al.*) states that the geographical elements of the evaluation depend on EPA’s interpretation of the statutory language CAA section 136(f)(6)(A)(i), which provides that, before an applicable facility can no longer be subject to the charge, the Administrator must determine that emission standards “have been approved and are in effect in all States with respect to the applicable facilities.” The commenter believes it would be reasonable for EPA to interpret CAA section 136(f)(6)(A)(ii) as allowing a national evaluation of equivalency only if EPA interprets CAA section 136(f)(6)(A)(i) to mean that no affected facility in any state can avoid the charge until all states have approved state plans that are in effect. If, however, EPA interprets CAA section 136(f)(6)(A)(i) to allow an applicable facility to avoid the charge if a state plan is in effect in any state in which the applicable facility operates, then correspondingly EPA should interpret CAA section 136(f)(6)(A)(ii) to require a state-by-state equivalency evaluation. Otherwise, the commenter cautions, affected facilities in a state that is not achieving emission reductions equivalent to the November 2021 Proposal would unfairly benefit from greater emission reductions required under more stringent requirements in another state.

Comment: Commenter (2433-EDF *et al.*) states that EPA should conduct a state-by-state analysis across all states nationwide to determine equivalency. As part of this analysis, the commenter believes that EPA must first evaluate the standards and plan in effect in each state to ensure that reductions equivalent those under the November 2021 Proposal are being achieved. The commenter explains that evaluating the standards and plans in every state aligns with CAA section 136(f)(6)(A)(i)’s directive to evaluate “standards and *plans* . . . in effect in all States” (emphasis added) for equivalency under section 136(f)(6)(A)(ii).

The commenter (2433-EDF *et al.*) further states that EPA should compare emissions reductions expected under each state’s final CAA section 111(d) plan to the emissions reductions that would have been achieved under the November 2021 EGs, if finalized in that state. The commenter explains that this follows from CAA section 136(f)(6)(A)(ii)’s directive that the comparison is to the proposed November 2021 emissions guidelines “if *such rule* had been finalized and implemented” (emphasis added), which contemplates a full implementation of the November 2021 proposed standards and emissions guidelines in each state. The commenter notes that, if a state’s final CAA section 111(d) plan achieves fewer reductions than the November 2021

Proposal's EGs, including due to variances granted pursuant to RULOF considerations, then EPA could not make the equivalency determination.

The commenter (2433-EDF *et al.*) states that evaluating equivalency with regard to each state incentivizes the greatest reductions in emissions under both the waste charge program and CAA section 111, whereas solely considering aggregated nationwide emissions (which could allow for lower emissions reductions in one state to be offset by higher emissions reductions in another state) does not. The commenter explains that, evaluating whether stronger standards in one state offset less stringent standards in another state would also be technically difficult, given that many section 111 standards are non-numerical design, equipment, work practice, and/or operational standards that do not quantify emissions.<sup>5</sup> However, according to the commenter, while a nationwide analysis in and of itself is insufficient in the absence of a parallel state-by-state analysis, EPA must still ensure that aggregated nationwide emissions reductions are equivalent or greater than those under the November 2021 Proposal. The commenter notes that, by ensuring that each state is achieving equivalent reductions under the CAA section 111(b) standards and its CAA section 111(d) plan, a nationwide determination of equivalency across all states should necessarily follow.

### ***9.1.3 Meaning of "Equivalent" Emissions Reductions***

Comment: Commenter (2458-MiQ) states that EPA should encourage states that share basins (*i.e.*, New Mexico and Texas with regards to the Permian Basin, and Pennsylvania, New York, and West Virginia for the Marcellus Basin) to work in conjunction with each other on equivalence evaluations.

Comment: Commenter (2326-AXPC) believes that that it is not appropriate to quantitatively compare the November 2021 Proposal with the December 2022 Supplemental Proposal, nor would it be appropriate to quantitatively compare the final rule with the November 2021 Proposal. The commenter notes that the November 2021 Proposal did not provide any regulatory text for proposed NSPS OOOOb or EG OOOOc, and certain proposed requirements were not technically feasible. The commenter states that EPA has understood that some of the requirements were not possible as EPA modified them in the December 2022 Supplemental Proposal. Therefore, the commenter provides that the emissions reductions expected within the November 2021 Proposal would not have been realized as estimated within the rule. That said, the commenter believes that the December 2022 Supplemental Proposal is at least as stringent as the November 2021 Proposal, due to the significant changes to the November 2021 Proposal in the December 2022 Supplemental Proposal, and states that if industry's comments and recommendations are implemented in full by EPA, the final rule would still be as stringent as the November 2021 Proposal. By way of example, the commenter points to Table 5-5 of EPA's 2022 Regulatory Impact Analysis (RIA), where it is apparent that fugitive emissions, pneumatic devices, and reciprocating compressors make up a large portion of the emissions reductions. That commenter adds that, with respect to fugitive emissions, the inclusion of additional ways to do aerial monitoring as well as the potential for continuous monitoring will result in increased

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<sup>5</sup> EPA discussed similar challenges in the supplemental proposal in the context of declining to conduct a total program evaluation for purposes of determining equivalency of a state plan with the OOOOc presumptive standards. See 87 Fed. Reg. at 74813.

emissions reductions from the November 2021 Proposal. Also, the commenter notes that the November 2021 Proposal exempted certain types of sources that are no longer exempted, resulting in additional emissions reductions. For pneumatic devices and reciprocating compressors, the commenter provides that the requirements for the supplemental proposal achieve significantly greater emissions reductions than the November 2021 Proposal.

Comment: Commenter (2326-AXPC) provides that, as long as the EGs established by EPA in the final rule are at least as stringent as the November 2021 Proposal, any approved state plan will inherently achieve equivalent or greater emissions reductions as compared to the November 2021 Proposal. The commenter believes that Congress enacted the MERP in full awareness of the long-standing text and structure of CAA section 111(d), and the MERP does not repeal by implication or in any other way detract from this other statutory provision, therefore, the only way to read these two statutory provisions (the MERP and CAA section 111(d)) in harmony is for EPA to deem any “satisfactory” state plan that it approves as equivalent to its own new regulations under CAA section 111(d). According to the commenter, to do otherwise would conflict with Congress’s earlier choice to establish an existing source regulation program mediated through a state-planning process. The commenter adds that for any state plans that EPA deems to be inadequate, the federal plan will act to replace the state plan and would serve as an equivalent plan.

Comment: Commenter (2433-EDF *et al.*) states that EPA should develop an updated analysis of the emissions reductions that would have been achieved by the November 2021 Proposal, if finalized and implemented. While EPA estimated emissions reductions in an RIA and Technical Support Document (TSD) for that proposal, the commenter believes that those emissions reductions were underestimated. Further, the commenter explains that the agency updated its methodologies and assumptions for calculating emissions impacts in the supplemental proposal. Thus, the commenter suggests that when EPA updates subpart W to ensure that reporting is based on empirical data pursuant to CAA section 136(h), it should also utilize that data to develop an updated analysis of the emissions reductions that would have been achieved under the November 2021 Proposal.

Comment: Commenter (2343-Institute for Policy Integrity at New York University School of Law) requests that EPA quantitatively compare the total emissions reductions of the November 2021 Proposal and December 2022 Supplemental Proposal, taking into account their stringencies in each year. Whether EPA adopts this approach for the final rule or not, they state it should explain that a quantitative review represents a best practice for future equivalency determinations. The comment further states that if EPA chooses not to apply a quantitative approach here, EPA should explain why this case is the exception because the December 2022 Supplemental Proposal tracks so closely with the November 2021 Proposal, as they are part of the same rulemaking.

#### ***9.1.4 Calculation of Waste Emissions Charge***

Comment: Commenter (2251-National Association of Manufacturers) is concerned about the effectiveness of the rule because the cost of the rule will affect the price of natural gas to manufacturers as fuel and as commodities. The commenter states that where the rule is not

correctly addressed, such as in Subpart W reporting, the reporting calculations might inadvertently affect the methane fee (tax) under the IRA. The commenter suggests technical corrections to ensure the IRA is implemented in a way that the calculation of the fee is more accurate, as follows:

- Correct subpart W reporting for the oil and gas sector.
- Declare that the emissions reductions under the final rule are greater than or equal to the emissions reductions that would have been achieved by the November 2021 Proposal had it been implemented.

### ***9.1.5 Compliance Determination***

Comment: Commenter (2326-AXPC) states that EPA has broad enforcement discretion on how to treat compliance, and EPA should interpret non-compliance for purposes of the WEC as long-term, knowing, and malicious states of noncompliance with the methane regulations. The commenter believes that Congress did not intend the MERP to as “double punishment” in the case of any potential for, or allegation of, any compliance violation.

Comment: Commenter (2399-GPA) supports EPA’s request to consider public input and provide stakeholders direction on the implementation of the IRA framework, which the commenter states could present an undue impact on the midstream sector. In particular, the commenter states that EPA should include direction on how to fairly apply the “exemption for regulatory compliance” provided in this new law, which encourages compliance as a way to minimize the financial charges that may result from the law. Moreover, the commenter supports EPA’s intention to provide a separate draft proposal on this topic to allow stakeholders to comment on specific regulatory text before issuing any final regulations.

Comment: Commenter (2399-GPA) recommends that EPA reasonably interpret the phrase “in compliance.” The commenter states that they previously provided suggestions regarding the application of the exemption for regulatory compliance<sup>6</sup> which they also incorporate in these comments. The commenter urges EPA to recognize the challenges with real world compliance with complex and detailed regulatory requirements and interpret the exemption reasonably to allow some measure of flexibility in determining whether a facility is “in compliance.” In the real world, the commenter states it is unreasonable to expect, if not impossible, for an individual affected facility to establish strict 100 percent “compliance” with all aspects of complex rules. Non-compliance can arise from minor technical or paperwork deviations or other process-related issues leading to brief emissions exceedances, explains the commenter. According to the commenter, it would be unreasonable for EPA to determine that a facility loses its regulatory compliance exemption for an entire year where it submits a late report or barely exceeds a threshold for a few minutes on one day, while reporting compliance the rest of the year. The commenter is concerned that such a narrow and strict approach would be unduly punitive and contrary to the basic notions of due process. Therefore, the commenter urges EPA to consider a reasonable “substantial compliance” standard for EPA’s chosen interpretation of “applicable facility,” allowing an appropriately flexible approach to avoid the harshness of what could

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<sup>6</sup> See GPA Midstream Comments to MERP Docket at 7- 8.

otherwise be a significant financial burden. The commenter states that EPA and states could provide further guidance on reasonable limits for this approach.

In addition, the commenter (2399-GPA) states that “in compliance” should allow for a broad safe harbor for a facility to promptly correct instances of non-compliance, consistent with routine monitoring, a compliance assessment or other auditing function. There is a well-worn path for regulated parties to follow, such as that laid out in EPA and state audit disclosure policies, that would provide an established mechanism for prompt correction of any non-compliance, states the commenter. The commenter believes that allowing this as a way to qualify for the exemption would incentivize sources to conduct additional compliance assessments and to timely correct any issues identified.

To the extent that a facility is not in substantial compliance with the applicable CAA section 111(b) or 111(d) standard, the commenter (2399-GPA) suggests that EPA incorporate a “notice and cure” process into its implementation of the waste emission exemption process. First, the commenter explains that EPA is authorized to revise its reporting regulations to ensure the emissions data reporting is accurate. The commenter believes that as part of those regulations, EPA should provide that applicable facilities would not be subject to a charge that may otherwise be owed unless and until EPA, or the relevant state permitting agency, issue a notification that the facility is not in substantial compliance with applicable CAA section 111(b) or (d) emission standards or requirements and that, if not promptly cured, a WEC will be assessed. The commenter believes that this would provide a financial incentive for the facility so notified to correct any issues to be in compliance. A notice and cure process would also ensure the waste emission charge is applied only where a facility has in fact failed to qualify for the regulatory exemption, states the commenter. The commenter maintains that a facility should not lose its regulatory compliance exemption for an entire year for non-material compliance concerns, such as a late report or minor exceedance of a threshold for a few minutes on one day. Similarly, the commenter states, a facility should not lose its regulatory compliance exemption where there is disagreement between a facility and EPA, or the governing state, regarding the application of a standard or the relevant state plan.

Determining whether a facility is “in compliance” is highly fact-specific and could be highly subjective without adequate safeguards, warns the commenter (2399-GPA). Here, a notice and cure process will better serve both EPA and regulated entities in fairly applying the charge to the correct facilities states the commenter. To accomplish that, the commenter explains that the notice and cure process should provide a facility with the option to confer promptly with EPA or the relevant state regarding the notice in the event the facility disputes the regulator’s findings. According to the commenter, that will allow a reasonable opportunity to resolve potential disagreements prior to a final WEC assessment. The commenter states there should also be an opportunity for the facility to exercise its rights to question the charge through a form of administrative or judicial review under the CAA. The commenter adds that applying the WEC without notice and cure opportunities would be unduly punitive and contrary to the basic notions of due process.

The commenter (2399-GPA) believes that this type of procedure would be consistent with the framework EPA has created. The commenter explains, that in CAA section 136(f)(6)(B),

Congress provided EPA with authority to resume charging a facility after first applying the compliance exemption where EPA later determines that either of the two conditions at CAA section 136(f)(6)(A)(i)–(ii) were no longer met (*e.g.*, methane emission standards not approved or not in effect in an applicable state). It stands to reason, the commenter explains, that prior to determining whether these two conditions have been met to have applied the exemption, EPA should first determine whether the facility is “in compliance” with applicable methane emission requirements, consistent with CAA section 136(f)(6)(A). The commenter states that having EPA provide the requisite notice fits seamlessly with this framework.

### ***9.1.6 Duration of the WEC***

Comment: Commenter (2326-AXPC) states that if EPA believes the language of the MERP requires a source to be in compliance at all times or the MERP would go back in place, it is unclear for how long the methane fee would be reinstated; *e.g.*, for only the applicable reporting year? The commenter notes that this interpretation would require the facility to collect information even if the fee does not apply, which would undermine the purpose of the regulatory exemption. The commenter believes that this additional unnecessary burden on the regulated entity and the administrative burden on the EPA, without providing any additional methane reduction, is a strong policy reason for why small compliance issues should not be treated as an initial triggering or a retriggering of the methane fee.

## **9.2 Funding and Technical Assistance for Emissions Reductions Programs**

### ***9.2.1 Assistance for Industry***

Comment: Commenter (2247-Ohio Environmental Protection Agency) notes that while the IRA has allocated significant monies to assist the owners of oil and gas wells with emission reduction programs, it is not possible at this time to estimate whether these funds are adequate to fulfill the immediate needs of the marginal well operators to comply with these proposed rules. Also, the commenter notes that IRA funding is a one-time allocation and although having funding from the federal government to assist with compliance costs is appreciated, it is unknown how much more funding would be needed to ensure compliance on an ongoing widescale basis.

Comment: Commenter (2224-Zero Emission Vacuum and Compressor (ZEVAC)) states that EPA should consider providing grants, rebates, and loans to fund company purchases of methane capture and recovery technology that can be used to mitigate and prevent emissions during downstream operations. The commenter contends that technology, and the framework for proper use, is an existing, proven way to avoid and reduce emissions and funding would support the purchase of necessary equipment, improve operator compliance with emission reduction goals, and support the integration of technologies with proven performance. Further, the commenter states that EPA should develop a list of “shovel ready” technology demonstration programs and include examples of current or recent technology and mitigation projects in downstream operations to provide guidance and direction for companies looking to improve their emissions reporting and compliance. The commenter explains that leveraging existing technology and projects can help speed up the implementation of new emissions regulations and improve their



effectiveness. Finally, the commenter suggests that the RACT/BACT/LAER clearinghouse<sup>7</sup> should be updated so that companies can become aware of technology that has been implemented and successfully achieved compliance.

### ***9.2.2 Assistance for Regulators (State/Local)***

Comment: Commenter (2249-National Association of Clean Air Agencies) asserts that EPA should use the funding resources provided by the IRA to augment its own capabilities and to support the capabilities of state and local air pollution control agencies that will implement and enforce the rule. The commenter notes that state and local air pollution control agencies already face a great variety of challenges, and if finalized, the proposed rule will require agencies to increase their investments in personnel and technical capabilities, and to incur other costs. The commenter notes that while federal grants support these state and local programs, the funding essentially has been flat since 2004 and in any event, developing new capabilities related to the rulemaking should not come at the expense of resources allocated to existing air programs. Further, the commenter urges EPA to consider funding beyond equipment procurement, as underinvesting in human resources, training, and technical assistance will yield challenges for planning, permitting, community engagement and enforcement by state and local agencies.

Comment: Commenter (2458-MiQ) states that EPA (in conjunction with Department of Energy) should assist states in making equivalency determinations, through technical assistance.

## **9.3 Target Setting and Tracking**

Comment: Commenter (2224-ZEVAC) states that EPA could provide value to corporate target setting and tracking by providing resources and technical support to standardize commitments and help companies implement voluntary climate action plans, including funding for research and development of new technologies and approaches. The commenter notes that implementation will run more smoothly if the revisions require the use of empirical data to account for company-specific methane emissions and reductions. Enhanced standardization of corporate climate commitments could provide a common framework and set of criteria for companies to use in setting and reporting on their commitments, according to the commenter. The commenter believes that this could help ensure that commitments are consistent and comparable across different sectors and industries and make it easier for investors and other stakeholders to understand and evaluate companies' progress.

## **9.4 Synergy with other programs**

Comment: Commenter (2166-Ohio Department of Natural Resources) states that it will be valuable, for the programs that result from the IRA funds, to require methane measurements to be collected as a rate measured in grams per hour rather than a concentration (ppm) so that the work completed under the IRA can be utilized when plugging results with Infrastructure, Investment, and Jobs Act (IIJA) future grants funds.

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<sup>7</sup> See <https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information>.

Comment: Commenter (2350-Cheniere Energy, Inc.) reports that several regulatory initiatives related to the oil and natural gas sector are in development in addition to this proposed rulemaking, including the requirements for the greenhouse gas reporting program (GHGRP) under Subpart W and the implementation of the IRA methane fee and MERP. The commenter notes that evolving measurement technologies offer EPA the opportunity to harmonize the methodologies used to satisfy both GHGRP and NSPS OOOO requirements, along with upcoming requirements for the implementation of the methane fee. The commenter recommends that approved technologies, and the conditions around their deployment such as survey frequency and probability of detection be consistent between the different regulatory programs. The commenter also recommends that EPA use modeling tools and public empirical datasets compiled by credible third-party experts, because creating a like-to-like comparison between facilities or operators in an evolving environment of measurement technologies is challenging. The commenter states that measurements from advanced technologies must be carefully interpreted so that their spatial and temporal scales align with those of the reporting program, noting that different technologies have different spatial and temporal characteristics, along with varying probabilities of detection and uncertainty. The commenter emphasizes that it is essential to use qualified experts familiar with how to accurately measure and quantify GHG emissions from oil and gas facilities when developing empirical data.

Commenter (2350-Cheniere Energy, Inc.) notes the Energy Emissions Modeling and Data Lab (“EEMDL”) is developing transparent models and datasets for accurate greenhouse gas emissions accounting across global oil and gas supply chains. EEMDL has three strategic approaches: (1) develop community models and tools for greenhouse gas emissions assessments, (2) make timely and high-resolution emissions datasets that are publicly available, and (3) create educational and training materials to enable the widespread use of EEMDL’s models and data. Modeling tools, such as those EEMDL is developing, may help EPA account for the different spatial and temporal scales of available measurement technologies, and support operators as they prepare annual GHGRP inventories based on empirical data. EEMDL’s datasets may be robust enough to help EPA conduct a robustness check on its bottom-up inventory, and even be used to prepare dynamic, empirical emission factors based on the previous year’s measurement data from industry.

Comment: Commenter (2442-WYCLG) states that EPA should address the Bureau of Land Management’s (BLM) Proposed Rule: Waste Prevention, Production Subject to Royalties, and Resource Conservation.<sup>8</sup> The commenter suggests that EPA address whether the BLM has encroached upon its authority to protect and regulate air quality<sup>9</sup> through its proposed rule and address any areas of inconsistency or duplication. By way of example, the commenter states that BLM recognizes that the EPA has “promulgated emissions limitations for pneumatic equipment and storage tanks as well as LDAR requirements for new and modified sources in the oil and gas production sector.”<sup>10</sup> Therefore, the commenter summarizes, the proposed Waste Prevention Rules allows “operators to comply with analogous EPA regulations as an alternative means of compliance with the BLM’s requirements.”

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<sup>8</sup> See 87 Fed. Reg. 73588 (Nov. 30, 2022).

<sup>9</sup> See *Wyoming v. U.S. Dep’t of Interior*, 493 F. Supp. 3d 1046 (D. Wyo. 2020).

<sup>10</sup> See 87 Fed. Reg. at 73595.

## 9.5 Miscellaneous

Comment: Commenter (2433-EDF *et al.*) states that Congress’s passage of the IRA, including provisions like the MERP, further cements EPA’s authority to regulate methane under CAA section 111 by recognizing and affirming its support. The commenter asserts that EPA’s authority and obligation to address methane pollution from oil and gas sources under CAA section 111 is expressly affirmed through CAA section 136(f)(6) in the MERP, which references EPA’s proposed regulations. Specifically, explains the commenter, CAA section 136(f)(6) provides for a potential exemption from the waste emissions charge under CAA section 136(c) for “compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111[.]”

Comment: Commenter (2333-LongPath Technologies, Inc.) suggests that EPA explore incentives, such as limited statutory exemptions from the methane waste program, for sites that employ continuous site-wide measurements of methane emissions with valid mass emission rate as per the EPA’s final rule standards. The commenter points to the emerging science showing that the most accurate means of determining total site-wide emissions is via measurement with 1) valid mass emission rate quantification and 2) continuous monitoring. By way of example, the commenter references one new study which demonstrates that high-frequency monitoring is essentially a prerequisite for accurate closure of top-down and bottom-up emissions estimation techniques.<sup>11</sup> The commenter notes that daily to sub-daily coverage is critical, given the high variability in emissions.<sup>12</sup>

Comment: Commenter (2393-Oklahoma Office of the Secretary of Energy and Environment) states that the fees collected by EPA under the MERP conflict with state’s own Emissions Fees. The commenter explains that emission fees have historically been collected at the state level, where the emissions are occurring, and where the inventory, permit, inspection, and enforcement programs are located. The commenter states that it is an unacceptable overreach by EPA to begin collecting fees on methane emissions, while simultaneously expecting states to greatly expand their current programs to cover existing sources under EG OOOOc. The commenter requests that EPA ensure in its “IRA equivalence determination” that any state that implements EG OOOOc through the submission of a state 111(d) plan is considered equivalent to reductions under EPA’s November 2021 Proposal, ensuring the state’s facilities are not subject to the federal methane fee.

Comment: Commenter (2425-Taxpayers for Common Sense) states that while EPA estimated the net compliance costs to industry, not all of the compliance costs will be shouldered by industry. The commenter points to the IRA, which will provide funds through the end of FY 2028 to the EPA in the way of grants, rebates, contracts, loans and other activities for methane mitigation and monitoring.<sup>13</sup> The commenter notes that Department of Energy also has been funding methane mitigation research. Finally, the commenter notes that taxpayers have also been

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<sup>11</sup> Daniels et al., Towards multi-scale measurement-informed methane inventories: reconciling bottom-up inventories with top-down measurements using continuous monitoring systems, in preprint: <https://doi.org/10.26434/chemrxiv2023-jp5nt>.

<sup>12</sup> See EPA Docket No. EPA-HQ-OAR-2020-0317.

<sup>13</sup> See CAA section 136(a)(1)-(4) and section 136(b).

shouldering some of the costs of operational and equipment improvement through various incentivizes to increased capture.

Comment: Commenter (2326-AXPC) recommends that EPA establish procedural regulations as soon as possible for how states and operators can petition the EPA for a determination (if EPA has not acted) and timeframes for when EPA will make the determination. The commenter states that EPA should allow owners or operators subject to the MERP; states where operators subject to the MERP operate; and trade association representing owners or operators subject to the MERP to petition EPA individually or jointly for a determination. The commenter recommends that EPA commit to reviewing and approving/disapproving petitions within three months of receiving a petition. The commenter further recommends that if EPA takes longer than three months to dispose of a petition, the methane fee payments made by operators (that would have been exempted if EPA had granted the petition) be held in abeyance or placed into a separate fund such that they can be refunded if the determination is made.

Comment: Commenter (2177-Southern Ute) asserts that the proposed methane fee does not address the environmental justice concerns, the driving force behind these regulations. The commenter requests that operations on tribal lands be excluded from the methane fee, or alternately, the funds be redistributed directly back to the Tribe. The commenter notes that all monies collected under this fee will not be distributed to their Tribe nor returned to the community to address the environmental impact of these emissions. Rather, the fee is being collected at the expense of their Tribe and goes directly into the EPA's funds. Thus, the commenter states that not only will the Tribe be hurt from a financial perspective overall, but the fees taken will in no way directly benefit their Tribe and Tribal members.

Comment: Commenter (3380-Douglas Elenbaas) states Michigan's Oil and Gas Industry does not warrant the new regulations on Existing Emission Sources that are covered under the EPA's proposed Subpart OOOOc. During 2021, Michigan had 15,748 active oil and gas wells (10,362 gas and 5,386 oil). The total annual production was 4,400,000 barrels oil and 71,800,000 mcf natural gas. Therefore, the average production for oil wells was 2.24 BOPD and for gas wells 20 Mcfd. Furthermore, there were only 25 producing properties making over 100 BOPD and 32 gas production properties delivering over 1,000 Mcfd.

Commenter (3380-Douglas Elenbaas) continues, assessing fees for natural gas emissions on pumping oil wells that are only active for a couple hours per day is excessive and fees associated would likely make a significant number of wells uneconomic. Likewise for gas wells, a significant number are operated on vacuum compression, so emissions are not feasible on wellheads and gathering lines. The commenter understands the need to reduce natural gas emissions but assessing fees must focus on large emitters. EPA should have production rate minimums similar to marginal wells such as a minimum of 10 BOPD or of 50 Mcfd.

## Chapter 10. Centrifugal Compressors

### 10.1 New Source Performance Standard (NSPS) OOOOb Affected Facility/Definitions

#### 10.1.1 Affected facility

Comment: Commenter (2428-American Petroleum Institute (API)) states that conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from 40 CFR 60.5365b(b). The commenter suggests that temporary compressors should be exempt from the monitoring requirements as it would be infeasible to conduct monitoring on a compressor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stationary source should not be subject to either NSPS OOOOb. The commenter requests that EPA make the following clarifications to address this concern (underlined text is new text) for centrifugal compressors [similar changes would apply to 40 CFR 60.5386c(b)]:

*40 CFR 60.5365b(b)-*

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.

Response II-10-1: With regards to the commenters' request that the applicability of the rule not apply to temporary, portable and emergency compressors because conducting measurements on temporary compressors is logistically impractical, the EPA disagrees.

The EPA considered similar comments on the November 2021 Proposal, see discussion in section IV.G.1.b of the December Supplemental Proposal preamble,<sup>1</sup> and maintains that basing reciprocating compressor flow rate monitoring on the hours of operation (*i.e.*, 8,760 hours) in lieu of requiring monitoring based on a calendar year addresses limited-use reciprocating compressors and allows owners and operators flexibility when planning maintenance.

Comment: Commenter (2257-Michigan Oil and Gas Association (MOGA)) recommends the EPA continue the exemption of both centrifugal and reciprocal compressors "located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility" as provided in both NSPS OOOO and NSPS OOOOa. Well operators visit and service these wells and associated compressors daily to inspect for proper operation, leaks and to conduct maintenance and repair activities. Any necessary repairs are repaired as soon as possible to avoid product loss and to maximize profit returns. If the EPA wishes to propose monitoring for well

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<sup>1</sup> 87 FR 74796, December 6, 2022.

site compressors, the commenter recommends the EPA allow the more feasible and cost-effective monthly auditory, visual & olfactory (AVO) inspection and documentation, similar to the requirements allowed under 40 CFR 60.5416a.

Response II-10-2: The final rule and emission guidelines retain the concept that centrifugal and reciprocating compressors located at a well site are not affected or designated facilities. However, compressors located at centralized production facilities are affected or designated facilities. Section XI.G.5 of the preamble to the final rule details EPA’s rationale and reasoning regarding the applicability of requirements to compressors located at centralized production facilities. Centrifugal compressors located at well sites are not subject to requirements. However, centrifugal compressors located at centralized production facilities that consist of equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells (including centrifugal compressors) are subject to centrifugal compressor requirements.

Comment: With respect to emissions standards on dry seal centrifugal compressors as part of NSPS OOOOb and [Emission Guidelines (EG) OOOOc]<sup>2</sup>, commenter (2301-U.S. Chamber of Commerce (USCC)) is concerned that the EPA has not followed the necessary process to demonstrate a legitimate nexus between the proposed additional sources—dry seal centrifugal compressors—and the existing sources within the category to be regulated, nor undertaken a process to expand the source category (or create a new one), consistent with the requirements of Clean Air Act (CAA) section 111(b)(1)(A).<sup>3</sup> The commenter notes that they provided a similar comment on the November 2021 Notice.<sup>4</sup> According to the commenter, the EPA must make the necessary findings under the CAA before expanding its regulations under section 111.

Specifically, to regulate greenhouse gas (GHG) emissions in the oil and natural gas sector under CAA section 111, the commenter (2301-USCC) asserts that the EPA must determine through rulemaking that (1) such “air pollution” endangers public health or welfare and (2) the pollutant-specific emissions from each of these sectors “contributes significantly” to that air pollution.<sup>5</sup> Requiring such a finding helps ensure that the imposition of new rules will have a meaningful effect on a meaningful problem. The EPA failed to comply with these statutory requirements in 2012 when transmission and storage sources were improperly brought into the production and processing segments without making the requisite findings.<sup>6</sup> As the original expansion of the source category to transmission and storage did not include the requisite statutory findings, if the EPA now adds dry seal centrifugal compressors to the transmission and storage segment, it would continue to improperly expand the source category in violation of the statute.

As it presently stands, the commenter (2301-USCC) states that the Methane Proposal would create standards for dry seal centrifugal compressors that were previously not regulated under

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<sup>2</sup> See 87 Fed. Reg. at 74,716 (“In this rulemaking, the EPA is proposing standards for dry seal centrifugal compressor and intermittent bleed pneumatic controllers for the first time in NSPS OOOOb and EG OOOOc.”); see also id. at 74,788–92 (outlining the proposed standards).

<sup>3</sup> See 42 U.S.C. § 7411(b)(1)(A).

<sup>4</sup> See Chamber January 2022 Comment Letter, at 10–11.

<sup>5</sup> Id.

<sup>6</sup> See 77 Fed. Reg. 49,490, 49,496–99 (Aug. 16, 2012).

NSPS and that are not described in the November 2021 Notice. And it would do so without any analysis of whether the operations share a proper commonality with the activities under the production and processing and transmission and storage segments. The commenter suggests that the EPA should therefore take this opportunity to help ensure the legal durability of these important proposed regulations by making all requisite findings for the transmission and storage segment, including those for dry seal centrifugal compressors.

Response II-10-3: The commenter is correct that NSPS OOOOa does not regulate dry seal compressors and that regulation of dry seal compressors was not proposed in November 2021 Proposal. However, this is not relevant as it was proposed in the December 2022 supplemental proposal and commenters had the opportunity to review EPA's proposal, as well as the analysis supporting the proposal. Therefore, the EPA feels that the rulemaking has followed all Administrative Procedure Act requirements and is therefore, finalizing standards and presumptive standards for dry seal compressors.

Comment: Commenter (2433-Environmental Defense Fund (EDF) et al) reaffirms their support for extending centrifugal compressor standards to centrifugal compressors at centralized production facilities.

Response II-10-4: This is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

### ***10.1.2 Definitions***

Comment: Several commenters (2282-Kinder Morgan, Inc, 2305-Williams Companies, Inc (Williams), 2399-GPA Midstream Association (GPA), 2428-API)<sup>7</sup> support the EPA's development of a new "self-contained wet seal centrifugal compressor" category in its proposed Rule and suggests that the EPA provide further definition on what industrial segments are included and excluded in the definition of "centrifugal compressor affected facility" at proposed 40 CFR 60.5365b(2)(b) [assumed to mean 40 CFR 60.5365b(b)]. According to one commenter (2305-Williams) the EPA makes no mention of compressor stations or processing plants: it is not clear if centrifugal compressors located in these industrial segments are subject to the proposed rule.

Response II-10-5: With regards to support for EPA's development of an alternative compliance option for "self-contained wet seal centrifugal compressor[s]", this is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

Regarding clarification of the industrial segments included and excluded in the definition of "centrifugal compressor affected facility", centrifugal compressor requirements apply to all oil and natural gas industry segments (which would include compressor stations and processing plants), which is why there was and is no specific industry segments specified as being included or excluded. 40 CFR 60.5365b(b) has therefore not been revised in the final rule.

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<sup>7</sup> 2428-API and 2282-KM support all 2399-GPA comments

Comment: Commenter (2428-API) states that clarification is requested to the definition of centrifugal compressor. Within the definition “centrifugal compressor” in 40 CFR 60.5430b [and §60.5430c], the EPA describes the compressor as “discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers.” The commenter requests that the phrasing of “significantly higher-pressure” should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The commenter (2428-API) explains that the definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb [and Emissions Guideline (EG) OOOOc] to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, the commenter (2428-API) provides that compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of the EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, the commenter recommends that EPA update 40 CFR 60.5430b to include a definition of significantly higher-pressure and includes the following language [a similar comment would also apply to EG OOOOc definition] (underlined text indicates new text):

*Centrifugal compressor* means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).

Response II-10-6: According to the commenter, with the expansion of the NSPS OOOOb [and EG OOOOc] to also include dry seal compressors, which are more widely utilized, clarifying changes are needed in the definition for centrifugal compressors to indicate what is meant by significantly higher-pressure to more-narrowly define applicability for dry seal centrifugal compressors, which would exclude a subset of dry seal centrifugal compressors from rule requirements. The EPA disagrees with the recommended change. Insufficient information/basis has been provided by the commenter to support making their suggested change which would limit applicability of the dry seal compressor requirements.

Also, in response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble. The December 2022 Supplemental Proposal regulatory text for centrifugal compressors under NSPS OOOOb and EG OOOOc does not require volumetric flow rate



monitoring if screening for emissions or leaks from the centrifugal compressor seal vent using optical gas imaging (OGI) or Method 21 does not indicate a leak. For dry seal centrifugal compressors that have a design pressure differential less than or equal to 300 psid that are screened as not having a leak, minimal recordkeeping and reporting is required. This has been maintained in the final NSPS OOOOb and EG OOOOc requirements. See final test methods and procedures for centrifugal compressors at 40 CFR 60.5385b and 40 CFR 60.5405c.

Comment: Commenter (2428-API) states that the proposed requirements for wet seal Centrifugal compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope (ANS).

The commenter (2428-API) explains that, on the ANS there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

The commenter (2428-API) continues by noting that wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in their January 31, 2022, comment letter.<sup>8</sup> The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum/tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, the EPA's Natural Gas Star<sup>9,10</sup> program, in conjunction with British Petroleum (BP), conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99.0 percent emission control by volume. The commenter reports that this same study is also cited by the California Air Resources Board (CARB) regulation references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, the commenter (2428-API) states that wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the "compressor suction." Because of this, these compressors would seemingly not meet the definition of "self-contained wet seal compressor." However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in 40 CFR 60.5430b [and 40 CFR 60.5430c]. Therefore, the commenter offers the following redline

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<sup>8</sup> EPA-HQ-OAR-2021-0317-0808.

<sup>9</sup> <https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf>.

<sup>10</sup> <https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoiddegassing.pdf>.

for the definition of self-contained wet seal centrifugal compressor (underlined text indicates new text and text struck out indicates deleted text):

*Self-contained wet seal centrifugal compressor* means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device ~~that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction~~ (i.e., degassed emissions are recovered). The de-gas emissions are routed back to ~~suction~~ a process or combustion device directly from the intermediate closed degassing process degassing/sparging chambers; ~~after the intermediate closed process~~ the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

Alternatively, the commenter (2428-API) suggests that EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a “self-contained wet seal compressor.”

Response II-10-7: The EPA appreciates the information and suggestion provided by the commenter. The EPA has not revised the definition of “self-contained wet seal centrifugal compressor” to include centrifugal compressors equipped with a sour seal oil separator where the seal oil degassing system captures most of the gas by volume then routes that gas to a flare. However, the EPA has made some of the clarifications to the definition suggested by the commenter and added a separate definition in the final NSPS OOOOb and EG OOOOc rules for “centrifugal compressor[s] equipped with sour seal oil separator and capture system” to address other comments provided on these compressors (see Responses II-10-28, 29 and 30 of this Chapter). The final definition for “self-contained wet seal compressor” included in NSPS OOOOb and EG OOOOc reads as follows:

*Self-contained wet seal centrifugal compressor* means:

(1) A wet seal centrifugal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (*i.e.*, degassed emissions are recovered) or which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to another process. The de-gas emissions are routed back to suction or process directly from the closed or intermediate closed degassing process; after the closed or intermediate closed degassing process the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.

(2) A wet seal centrifugal compressor equipped with mechanical wet seals, where (1) a differential pressure is maintained on the system and there is no off gassing of the lube oil, and (2) the mechanical seal is integrated into the compressor housing.

The EPA has also established alternative standards/presumptive standards for wet seal centrifugal compressors equipped with sour seal oil separator and capture system that are located in Alaska. See XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the final rule preamble for EPA's rationale for these changes.

Comment: Commenter (2348-Energy Workforce & Technology Council (EWTC)) requests that EPA add the following to the definition of centrifugal compressor:

The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions for the purpose of production, NOT intervention.

Response II-10-8: The commenter does not provide any reasoning or support for the need for their suggested change to the centrifugal compressor definition. This requested definition is ambiguous and to an extent misleading. The definition seems to align more with a high-pressure pump (frac pump) than a centrifugal compressor. These are distinct types of equipment that are utilized differently in the oil and gas industry. The former is used for hydraulic fracturing operations for generating high pressure to inject fluids (water, proppant and added chemicals) into formation. The latter is utilized in the industry as well as others to handle continuous flow of gases and provide relatively constant pressure ratio. These equipment's differ in function, design operation and application. Therefore, the EPA has not made the requested change. Note also that the centrifugal compressor definition included in the NSPS OOOOb and EG OOOOc rules is also included in NSPS OOOOa.

## **10.2 NSPS OOOOb Proposed Best System of Emission Reduction (BSER)**

[**Note:** Many of the comments provided in this section also apply to EG OOOOc. For BSER-related comments that were only provided on EG OOOOc for centrifugal compressors, see section 10.4.]

### ***10.2.1 Wet Seal Compressors***

Comment: Commenters (2282-Kinder Morgan, Inc, 2258-Marcellus Shale Coalition (MSC)) support the EPA's recognition that [self-contained] wet seal systems have low seal emissions and additional controls should not be required. The commenters note that a volumetric flow rate requirement is appropriate. One commenter (2258-MSC) adds that the EPA should allow additional flexibility in reducing or controlling seal emissions to meet the flow requirement. The commenter notes that technology to reduce emissions, such as seal gas recovery, is relatively new and emerging and the regulation should not discourage these options.

Response II-10-9: With regards to support for EPA's recognition that [self-contained] wet seal systems have low seal emissions, where a volumetric flow rate requirement is appropriate, this is

a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

In response to request that the EPA allow addition flexibility in reducing or controlling seal emissions to meet flow requirements, the final NSPS OOOOb standard and EG OOOOc presumptive standard requirements do not limit owners and operators from employing technologies that reduce emissions to meet performance-based volumetric flow rate requirements.

Comment: Commenter (2282-Kinder Morgan, Inc) states that the standard for wet seals in NSPS OOOOb should also be an emissions rate limit. The commenter appreciates that the Supplemental Proposed NSPS adjusted the approach for existing wet seals, finding a BSER based on preventative maintenance and repair to maintain a specified volumetric flow rate for wet seals on existing units in EG OOOOc. However, the commenter states that the Supplemental Proposed NSPS does not take this approach for new wet seals, despite many of the same considerations applying to new wet seals. Rather, the proposed BSER for new wet seals under NSPS OOOOb is to capture and route emissions to a control device.<sup>11</sup> Because the same considerations for existing wet seals apply to new wet seals, the commenter asserts that the EPA should also incorporate the emissions flow rate approach for wet seals in NSPS OOOOb.

The commenter (2282-Kinder Morgan, Inc) cites the their 2022 comments, which are attached as Exhibit B in their comment letter, were not limited to just EG OOOOc but were on proposals related to wet seals in both NSPS OOOOb/EG OOOOc,<sup>12</sup> and many of its arguments apply with equal force to new wet seal centrifugal compressors because replacing a compressor at an existing compressor station would not affect the footprint of that compressor station. Thus, the arguments regarding existing flaring capabilities, compressor station layout, and risk of explosion, which the EPA credited with respect to existing wet seal centrifugal compressors,<sup>13</sup> apply equally to new wet seal centrifugal compressors.

Further, the commenter (2282-Kinder Morgan, Inc) adds that Supplemental Proposed NSPS's conclusion that routing wet seal emissions to a control device is cost-effective in the natural gas transmission and storage industry segment is flawed, even using the EPA's own cost data. The Supplemental Proposed NSPS states that "the costs of routing the captured gas from the centrifugal compressor wet seal degassing system to a control device are reasonable for the control of methane for the gathering and boosting, processing and transmission, and storage segments using both the single and multipollutant approaches."<sup>14</sup> However, an inspection of Table 32 in the Supplemental Proposed NSPS reveals this conclusion to be false for the transmission and storage segment. Table 32 states that the cost of routing emissions to a control device in the transmission and storage segment under the single-pollutant approach is \$1,973 for

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<sup>11</sup> See 87 Fed. Reg. at 74,787. Kinder Morgan notes that this is different than the proposed BSER in the Original Proposal, which included routing to a process. See 86 Fed. Reg. at 63,119. Kinder Morgan appreciates that EPA recognized "that this option may not be available in situations where downstream equipment capable of handling a low-pressure fuel source is unavailable." 87 Fed. Reg. at 74,785.

<sup>12</sup> See Kinder Morgan 2022 Comments, at 2 (defining "Wet Seal Proposal" as the proposal found at pages 63,220–24, which set forth proposed standards for both Subparts OOOOb and OOOOc).

<sup>13</sup> See 87 Fed. Reg. at 74,791 (crediting such concerns with respect to the Subpart OOOOc wet seal proposal).

<sup>14</sup> Id. at 74,784.

methane and \$71,240 for volatile organic compounds (VOC).<sup>15</sup> Both costs exceed the reasonableness thresholds for methane and VOC in the Supplemental Proposed NSPS.<sup>16</sup> Regarding the multipollutant approach, the Supplemental Proposed NSPS states that both pollutants must be found cost effective to pass the multipollutant test,<sup>17</sup> but Table 32 reveals that only methane is cost-effective on a multipollutant basis.<sup>18</sup> In short, even based on the EPA's own analysis and reasonableness thresholds, routing to a control device in the transmission and storage segment is not cost-effective under either the single pollutant or multipollutant basis.

Similarly, commenter (2428-API) states that the wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc. The commenter notes that it is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and “self-contained wet seal compressors” can only comply with volumetric standard. All other wet seal compressors can only comply with the 95.0 percent capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95.0 percent through a control standard.

The commenter (2428-API) suggests that the implications of the NSPS OOOOb regulations seem to be that the 3 standard cubic feet per minute (scfm) volumetric standard is equivalent to the 95.0 percent capture and control requirement. If this is the case, then it stands to reason, according to the commenter, that all centrifugal compressors should be able to choose to comply with either the volumetric standard or the 95.0 percent capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, the commenter (2428-API) states that it obviates the need for a specially defined class of compressors: “self-contained wet seal compressors.” Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. The commenter states that the NSPS OOOOb standards would mimic the EG OOOOc standards.

Response II-10-10: The EPA maintains, as it did in the December 2022 Supplemental Proposal, that, for all segments, the costs in relation to the emission reductions were reasonable for all options evaluated as BSER for wet seal compressors under the NSPS OOOOb.<sup>19</sup> However, the options to route captured gas to a control device or to a process achieve greater emission reductions than conducting maintenance and repair to maintain the volumetric flow rate at or below 3 scfm per seal and was not and has not been adopted as BSER under the final NSPS OOOOb requirements. Under the EG OOOOc, BSER was determined to be maintenance and repair to maintain the volumetric flow rate at or below 3 scfm because of particular concerns and challenges that would be associated with retrofitting existing wet seal centrifugal compressors to

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<sup>15</sup> Id. at 74,787.

<sup>16</sup> See id. at 74,718 (The proposed thresholds are \$1,970/ton for methane and \$5,540 for VOC.).

<sup>17</sup> See id. at 74,787 tbl.32 n.b (For multipollutant approach, “the cost effectiveness of both methane and VOC . . . must be within the ranges considered reasonable by EPA.”).

<sup>18</sup> Id. at 74,787 tbl.32.

<sup>19</sup> 87 FR 74787.

accommodate reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater.<sup>20</sup> Although the EPA has not included the emissions flow rate approach for wet seals in NSPS OOOOb, the EPA has made revisions to the NSPS OOOOb requirements for wet seal compressors to allow owners and operators added flexibility in meeting the NSPS OOOOb standards for specified centrifugal compressors in the final rule. The EPA has also revised, but not removed the definition of self-contained centrifugal compressors in the NSPS OOOOb final rule. See section X.G.1 of the final rule preamble for a summary of the final rule requirements for centrifugal compressors.

Comment: Commenters (2282-Kinder Morgan, Inc, 2483-Interstate Natural Gas Association of America (INGAA)) appreciate and support the EPA acknowledging self-contained wet seal compressors as BSER. However, the commenters note there are flaws in the provision as proposed. With respect to self-contained wet seal compressors, the EPA not only specified that self-contained wet seal compressors are BSER due to their inherently very low emission rate; the EPA also adopted an emission rate of 3 scfm for the lube oil tank vent from which a small amount of residual gas is released because, according to the EPA, “there could be increased emissions due to leaks and malfunctions.” This is speculation. According to the commenters, there is nothing in the record indicating that this ever has occurred at a self-contained compressor, and the commenter is not aware of any occurrences. According to the commenters, manufacturer recommended maintenance is more than adequate to ensure a very low emission rate from self-contained wet seal compressors.

Response II-10-11: With regards to support for EPA’s recognition that [self-contained] wet seal systems have low seal emissions, this is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required. The EPA, however, has maintained the requirement to conduct performance-based volumetric flow rate monitoring for self-contained centrifugal compressors in both the final NSPS OOOOb standards and final EG OOOOc presumptive standards.

The EPA disagrees, however, that manufacturer recommended maintenance is more than adequate to ensure a very low emission rate from self-contained wet seal compressors. In order to allow for an alternative standard to the NSPS OOOOb BSER for self-contained wet seal compressors (which was included based on information provided by industry), the EPA needs to be assured that any potential leaks are identified and repaired. Based on the December 2022 Supplemental Proposal and final NSPS OOOOb rule requirements. The December 2022 Supplemental Proposal and final rule requirements for self-contained wet seal compressors do not require volumetric flow rate monitoring if screening for emissions or leaks from the centrifugal compressor using optical gas imaging (OGI) or Method 21 does not indicate a leak.

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<sup>20</sup> The cost of routing emissions to a control device in the transmission and storage segment under the single-pollutant approach of \$1,973/ton of methane is considered reasonable. The cited \$1,970/ton of methane was based on rounding and not considered a hard threshold of reasonableness, just illustrative of \$/ton (rounded) that were considered reasonable under the proposal BSER analyses evaluated. In fact, the EPA stated in the December 2022 Supplemental Proposal that the cost-effectiveness value of \$1,970/ton of methane reduction considered reasonable for controls identified as BSER in the November 2021 proposal and the supplemental proposal were well below the \$2,185/ton of methane reduction that EPA has previously found to be reasonable for the industry. 87 FR 74719.

See final test methods and procedures for centrifugal compressors at 40 CFR 60.5385b and 40 CFR 60.5405c.

Comment: Several commenters (2258 MSC, 2282-Kinder Morgan, Inc, 2305-Williams, 2399-GPA, 2428-API, 2483-INGAA) request clarification that the volumetric standard applies to each seal and not each compressor and that the rule text clearly addresses manifolded vents on a combined basis. The commenters cite the precedent set by the California Air Resources Board (CARB) where wet seal compressors in California are restricted to 3 scfm per seal, and not per compressor as set forth in 17 CCR § 95668, Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (underlined text reflects new text):

§ 95668 Standards

(d) Centrifugal Natural Gas Compressors

(6) A compressor with a wet seal emission flow rate greater than three (3) scfm, or a combined flow rate greater than the number of wet seals multiplied by three (3) scfm, shall be successfully repaired....

Commenter (2282-Kinder Morgan, Inc) further notes that the California program and the Gas STAR document cited by the EPA use a per-seal approach and that Solar Turbines' Product Information Letter (PIL) is also on a per-seal basis, clarifying that many centrifugal compressor models have two or more seals per compressor.

Commenters (2305-Williams, 2399-GPA) cite that their actual annual compressor measurements collected pursuant to the EPA's Greenhouse Gas Reporting Program indicate that a 3 scfm per seal threshold is a reasonable indicator of a self-contained wet seal compressor not operating properly.

According to commenter (2282-Kinder Morgan, Inc), the EPA's preamble discussion, and at least some of the proposed rule text, imply that the emissions rate would be on a per-seal basis, and the commenter understands this to be the EPA's intent. The commenter provides that it is important that the EPA's final rule more clearly reflect this intent. Specifically, according to commenter (2428-API) the proposed text provided in 40 CFR 60.5380b or 40 CFR 60.5385b(a), does not provide the distinction that the limits are per seal. According to the commenter, it would be impractical for a compressor with multiple seals (centrifugal) to operate the same as compressor with only a single seal.

Commenters (2282-Kinder Morgan, Inc, 2428-API) request that the rule language more clearly address manifolded vents on a combined basis. The commenters state that the Supplemental Proposed NSPS preamble provides that the manifolded wet and dry seal flow rate must be "less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode)."<sup>21</sup> The commenters support this approach, as it reflects the practicalities of measuring emissions from manifolded seals. The commenters also note that the approach is

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<sup>21</sup> 87 Fed. Reg. at 74,790, 74,792.

supported by the 2006 Natural Gas STAR report, which states that emissions rates from two seal systems would be double the emissions from a single seal system.<sup>22</sup>

Commenter (2282-Kinder Morgan, Inc) states that it appears that this concept of multiple seals manifolded to one vent is intended to be captured in the proposed regulations at 40 CFR 60.5380b(a)(5)(i)–(ii), 60.5415b(d)(2), 60.5392c(a)(2)(i)–(ii), and 60.5415c(c)(1). However, the proposed regulatory sections addressing the actual volumetric flow rate requirement do not clearly incorporate the preamble concept of multiplying the emissions rate by the number of manifolded seals. Proposed 40 CFR 60.5380b(a)(4)(i) and 60.5392c(a)(1) provide that the volumetric flow rate must not exceed 3 scfm, but they do not mention manifolded seals. Likewise, proposed 40 CFR 60.5415b(d)(2) and 60.5415c(c)(1), pertaining to demonstrating compliance, do not mention manifolded seals either. The commenter provides that this lack of regulatory text on manifolded seals makes it difficult for operators to rely on the preamble text alone. Moreover, for internal compliance processes, operators do not always cross-reference the preamble pertaining to each regulatory provision.

Several commenters (2282-Kinder Morgan, Inc, 2305-Williams, 2428-API, 2483-INGAA) provide suggested regulation text changes that would clarify the intent of the Supplemental Proposed NSPS preamble to allow for grouping of manifolded wet and dry seal vents where an emissions rate limit is applicable to such seals and that the emissions rate standard is on a per-seal basis. The commenters note that their suggested changes align with the CARB rule, and how it describes manifolded, or combined, seals.<sup>23</sup> and §95668 (c)(4)(D) of the 2017 California’s GHG Emissions Regulations, which this proposed standard was based.

Commenter (2305-Williams) recommends that EPA revise 40 CFR 60.5380b(4)(i) as follows:

- i. The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal.

Commenter (2428-API) recommends the following regulation text changes to 40 CFR 60.5380b(a)(4)(i) and 40 CFR 60.5392c(a)(1) (underlined text reflects new text):

*40 CFR 60.5380b(a)(4)(i):* The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.

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<sup>22</sup> EPA, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, at 2 (Oct. 2006), [https://www.epa.gov/sites/default/files/2016-06/documents/ll\\_wetseals.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/ll_wetseals.pdf) (stating that “dry seals leak at a rate of 0.5 to 3 scfm across each seal (1 to 6 scfm for a two-seal system)”).

<sup>23</sup> See 17 Cal. Code Regs. § 95668(c)(4)(D), (d)(6) (provisions for centrifugal compressors and reciprocating compressor rod packing both specify “a combined flow rate” based on the number of seals or compression cylinders multiplied by the applicable emissions standard for a single seal or rod packing unit).



*40 CFR 60.5392c(a)(1)*: You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.

Commenter (2282-Kinder Morgan, Inc) requests that the EPA incorporate modest changes to 40 CFR 60.5392c(a)(1), (a)(2)(i), 60.5410c(c)(1), and 60.5415c(c)(1), as well as the respective NSPS OOOOb provisions.<sup>24</sup> [Note: This comment also refers to the respective NSPS OOOOb provisions, however the redline provided is only noted for EG OOOOc provisions.] These proposed changes would align the regulatory language with the fact that it is not possible to determine the vent rate value for each individual seal in a manifolded seal arrangement.

*40 CFR 60.5392c(a)(1)*, proposed changes (underlined text reflects new text):

(1) You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per wet or dry seal, or in the case of manifolded groups of dry or wet seals, 3 scfm multiplied by the number of seals.

The commenter (2282-Kinder Morgan, Inc) also suggests two changes globally in the centrifugal compressor affected facility section to ensure consistent use of terms, with the proper meaning as is intended to apply in practice. First, when referring to the volumetric flow rate of 3 scfm, this rule should be referring to an individual wet seal or dry seal. The rule should not refer to the centrifugal compressor itself, or the seal vent, when referring to the required volumetric flow rate (i.e., the BSER threshold). Notably, a single centrifugal compressor can have more than one wet or dry seal, and thus, more than one wet or dry seal vent. Second, and in contrast to the above, when the rule refers to the point where the volumetric flow rate is measured, the rule should be referring to the seal vent or stack. In cases where multiple seals are manifolded together, the combination of seals would be measured as one vent/stack. The commenter recommends specific regulatory text changes to address their concerns.

*40 CFR 60.5392c(a)(1)(i)*, proposed changes (underlined text reflects new text):

(i) You must conduct your first volumetric flow rate measurement from your centrifugal compressor dry or wet seal vent on or before 8,760 hours of operation [Insert Date 36 months after state plan submittal deadline] or on or before 8,760 hours of operation after startup, whichever is later.

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<sup>24</sup> The commensurate sections in Subpart OOOOb would be §§60.5380b(a)(4)(i), (a)(5)(i), 60.5410b(d)(6), and 60.5415b(d)(2).

As an example, the commenter (2282-Kinder Morgan, Inc) notes that, relevant to the above comment, because 40 CFR 60.5392c(a)(1)(i) and (ii) are discussing when to take the measurement, the commenter refers here to the seal vent, and not the seal itself. Here the centrifugal compressor is what will be in “operating-mode or in standby-pressurized mode”, so we propose to re-order the text to reflect that fact. The second sentence is not necessary. The commenter has proposed changes to 40 CFR 60.5392c(a)(1) to address the required volumetric flow rate (i.e., BSER) for more than one seal, which clarifies that when you have more than one seal manifolded to one vent, the required volumetric flow rate threshold is 3 scfm multiplied by the number of seals. Then, the commenter adds that the EPA’s proposed 40 CFR 60.5392c(a)(2)(ii) already addresses the appropriate measurement methodology when more than one wet or dry seal is manifolded together to a single vent/stack. So, it is unclear to the commenter what this second sentence offers that is not already addressed by other rule language. Furthermore, as the EPA addressed in the preamble to the Supplemental NSPS Proposal, when more than one seal is routed to the same vent, the operator cannot determine individual seal flow rates and “sum” them. Thus, this language, as drafted creates confusion as to how an operator would “sum” multiple measured rates from each seal. The commenter provides suggested regulation text changes below [suggested changes would also apply to parallel provisions in the proposed NSPS OOOOb].

*40 CFR 60.5392c(a)(2)(i)* proposed changes (underlined text reflects new text and struck out text reflects deleted text):

(i) For each dry or wet seal centrifugal compressor ~~vents~~ in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry or wet seal vent using one of the methods specified in paragraphs (a)(2)(i)(A) through (C) of this section. ~~If there is more than one dry seal compressor or wet seal compressor seal vent, determine the aggregate centrifugal compressor dry or wet seal vent volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for each dry seal compressor or wet seal compressor vent on the compressor.~~

*40 CFR 60.5392c(a)(2)(ii)* proposed changes (underlined text indicates new text and struck out text indicates deletions):

(ii) For conducting measurements on manifolded groups of dry or wet seals centrifugal compressors, you must determine the volumetric flow rate from the ~~compressor~~ dry or wet seal vent as specified in paragraph (a)(2)(ii)(A) or (B) of this section.

(A) Measure at a single point in the manifold downstream of all dry or wet seal compressor inputs and, if practical, prior to comingling with other non-~~compressor~~-seal emission sources.

(B) Determine the volumetric flow rate at standard conditions from the common stack using one of the methods specified in paragraph (a)(2)(i)(A) through (~~E~~) of this section.

Changes recommended for *40 CFR 60.5392c(a)(2)(ii)* reflect the recommended paragraph additions to *40 CFR 60.5392c(a)(2)(i)* (see section 10.5.3 for this commenter’s

requested additions) and recommended monitoring changes based on the measurement of manifolded wet and dry seal vent inputs to meet a per seal standard.

*40 CFR 60.5410c(c)(1)* proposed changes (underlined text reflects new text and struck out text reflects deleted text):

(1) You must maintain the volumetric flow rate at or below 3 scfm for your wet ~~and or~~ dry seal ~~centrifugal compressors~~ (or in the case of manifolded groups of wet or dry seals, 3 scfm multiplied by the number of seals) and you must conduct your initial annual volumetric measurement as required by §60.5392c(a)(1)(i).

*40 CFR 60.5415c(c)(1)* proposed changes (underlined text reflects new text and struck out text reflects deleted text):

(1) You must maintain volumetric flow rate of each dry or wet seal below 3 scfm (or in the case of manifolded groups of dry seal or wet seals, 3 scfm multiplied by the number of seals) and you must conduct the required volumetric flow rate measurement ~~of~~ at your dry or wet seal vent ~~centrifugal compressor~~ in accordance with §60.5392c(a)(1) and (2) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrates compliance with the ~~3 scfm~~ applicable volumetric flow rate.

Commenter (2483-INGAA) also suggests regulatory language [assuming standard changed from an emission limit standard to a work practice standard] to address the same per seal volumetric flow rate clarification and measurement issues as follows (underlined text reflects new text and struck out text reflects deleted text):

Proposed regulatory text changes for *40 CFR 60.5392c(a)* and *60.5380b(a)*: A new paragraph 40 CFR 60.5392c(a)(1)(iii) should be added as follows (underlined text reflects new text and struck out text reflects deleted text):

(1) You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. If the ~~The~~ volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, ~~must not exceeds~~ 3 standard cubic feet per minute (scfm) multiplied by the number of wet seals connected to the vent, the wet and dry seals connected to the measured vent must be repaired as provided in paragraph (a)(1)(iii) of this section.

[...]

(iii) The seal repair must be conducted no later than the next scheduled compressor station shutdown for maintenance. Delay of repair beyond the next compressor station shutdown for maintenance is allowed for a centrifugal compressor wet and dry seal, if seal replacement is necessary during the compressor station shutdown for maintenance, seal supplies have been depleted, and seal supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next compressor station shutdown

for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance. You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section within 15 days after the repair to document that the rate has been reduced to less than 3 scfm per seal.

*Proposed 40 CFR 60.5392c(a)(2)(i)* suggested regulation text changes as indicated in the language below (struck out text reflects deleted text):

(i) For centrifugal compressor dry or wet seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry or wet seal vent using one of the methods specified in paragraphs (a)(2)(i)(A) through (C) of this section. ~~If there is more than one dry seal compressor or wet seal compressor seal vent, determine the aggregate centrifugal compressor dry or wet seal vent volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for each dry seal compressor or wet seal compressor vent on the compressor.~~

*Proposed 40 CFR 60.5380b(a)(4)(i)* suggested regulation text changes as indicated in the language below (underlined text reflects new text and struck out text reflects deleted text):

(i) ~~The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm).~~ You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section. If the volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, exceeds 3 standard cubic feet per minute (scfm) multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(6) of this section.

*Proposed 40 CFR 60.5380b(a)(5)(i)* suggested regulation text changes as indicated in the language below (struck out text reflects deleted text):

(i) For centrifugal compressor dry seal vents or self-contained wet seal centrifugal compressor in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry seal vent or self-contained wet seal centrifugal compressor using one of the methods specified in paragraphs (a)(5)(i)(A) through (C) of this section. ~~If there is more than one dry seal vent or self-contained wet seal centrifugal compressor, determine the aggregate dry seal vent or self-contained wet seal centrifugal compressor volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for each centrifugal compressor dry seal vent or self-contained wet seal centrifugal compressor.~~

Response II-10-12: Section XI.G.3 (Clarification that the standard is based on a per-seal basis) of the preamble to the final rule responds to these comments. The EPA agrees that the basis and

intent of the performance-based volumetric flow rate standard is that it be applied on a per-seal basis and that clarity was needed in both the NSPS OOOOb and EG OOOOc regulatory text. EPA considered the comments/suggested edits and made the necessary clarifying changes to the final NSPS OOOOb and EG OOOOc regulatory text to address commenter's concerns.

Comment: Commenters (2282-Kinder Morgan, Inc, 2483-INGAA)<sup>25</sup> note that EPA stated that it is also considering other types of inherently low-emitting wet seals. Commenter (2483-INGAA) has previously submitted information on mechanical wet seals that it believes is sufficient to designate such designs as BSER for compressors that use them.<sup>26</sup> The commenter submits additional information on mechanical wet seals in Attachment D to their comments. With respect to mechanical wet seals, the commenters add that when a differential pressure maintained on the system, there is no off gassing of the lube oil. The commenter attaches an example to their comment letter that shows that the oil is pumped via the seal oil pump to the seal gas bottle, when the seal oil pressure is maintained at 32 psi above discharge gas pressure. With the differential pressure applied, the oil follows the (yellow) line down to the seals to maintain mechanical contact between the carbon ring and the seal collar. The reference line serves 2 purposes: (1) as a reference for seal oil pressure and (2) to push sour oil through to processing. The green line is the sour oil drain to the Armstrong dump valves. The Armstrong dumps are regulated via a float/needle & seat valve. The only way to lift the float off its seat in the dump is to introduce a liquid (sour oil) to the pot. Another unique feature of this type of mechanical seal is that it is integrated into the compressor housing. It has pins holding it in place. It is more expensive to convert one of these units to dry seals because the housing would need to be machined out to remove it. Then a mechanical seal with limited venting is replaced with a dry seal that has continuous venting.<sup>27</sup>

Response II-10-13: Section XI.G.3 (Other inherently low-emitting compressor with wet seal configurations) of the preamble to the final rule responds to these comments.

Comment: Commenter (2433-EDF et al.) states that the EPA should further strengthen the wet seal compressor standards by prioritizing control methods that route captured gas to a process rather than a completion device. [This comment applies to both NSPS OOOOb and EG OOOOc.]

Response II-10-14: The EPA does not have information that would support requiring an owner or operator to route to a process over routing captured gas to a combustion control device. However, the EPA encourages owners and operators choose that option (where technically feasible) and the December 2022 Supplemental Proposal and the final regulatory requirements for demonstrating compliance with the routing to a process option are less than what is required

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<sup>25</sup> 2282-Kinder Morgan noted in their comments that they support all 2483-INGAA comments.

<sup>26</sup> INGAA Comments on 2021 Partial Proposal at 24.

<sup>27</sup> The cost difference to convert a mechanical wet seal to a dry seal is about \$150K-\$400K more than converting a clearance wet seal to a dry seal. The range depends on overhung (1 seal) vs beam (2 seals). Significant engineering is involved for mechanical wet seals manufactured by Delaval because the mechanical wet seal is locked in place using the bearing housing and there is no removable barrel. Therefore, machining the compressor case would be required.

if an owner or operator reduces emissions by routing to a combustion control device under both NSPS OOOOb standards and EG OOOOc presumptive standards.

Comment: The EPA solicited comment on its assumption that the emissions reduced by requiring the capture of gas and routing to a process is 95 percent or greater. The EPA also solicited comment on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa or other rules by routing emissions from the wet seal fluid degassing system to a process and the need for a vapor recovery unit (VRU) in order to be able to route emissions from the wet seal fluid degassing system to a process.

In response, commenter (2333-LongPath) states that their experience with continuous monitoring shows that continuous quantitative (emission rate) monitoring data is extremely effective at aiding operators in properly maintaining set points of VRUs. The commenter suggests that the EPA allow for quantitative continuous monitors with full site coverage to be usable as a form of VRU efficiency monitoring.

Response II-10-15: The EPA appreciates the commenter's input. While the EPA is not requiring continuous monitoring of VRU "set points" at this time as a form of VRU efficiency monitoring due to insufficient information, owners or operators would be allowed to employ continuous monitoring of "set points" of their VRUs as a form of VRU efficiency monitoring under the final NSPS OOOOb and EG OOOOc rule requirements.

### ***10.2.2 Dry Seal Compressors***

Comment: Commenter (2218-Texas Commission on Environmental Quality (TCEQ )) states that EPA's Oil and Gas Control Techniques Guidelines (CTG) model rule and current TCEQ rules do not require additional controls for centrifugal compressors with dual dry seals, which are already assumed to be 95.0 percent more effective than centrifugal compressors with wet seals. The model rule's additional centrifugal compressor dry seal control requirements are both economically unreasonable and unduly burdensome.

Response II-10-16: In response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble.

Comment: Commenter (2258-Marcellus Shale Coalition (MSC)) contends that the EPA should allow additional flexibility in means for reducing or controlling dry gas seal emissions. Technology to reduce emissions, such as seal gas recovery, is relatively new and emerging and the regulation should not discourage these options. In addition, the use of proven add-on controls, such as a combustor, should be allowed. Such options may be key for modified or reconstructed units.

Response II-10-17: In response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach for dry seal centrifugal compressor

affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble. As an alternative to meet the dry seal performance-based volumetric NSPS OOOOb standards and EG OOOOc presumptive standards, the EPA has revised the requirements for centrifugal compressors equipped with dry seals to allow owners and operators to comply with the VOC and GHG standards for compressors with dry seals by reducing VOC and methane emissions from each centrifugal compressor dry seal system by 95.0 percent, or by comply with the option to route the emissions from each centrifugal compressor dry seal system to a process.

Based on the final requirements, seal gas recovery would be allowed, however, the compressor would need to be able to comply with the final NSPS OOOOb standards and EG OOOOc presumptive standards (*e.g.*, by complying with either the performance-based volumetric flow rate standard or the route to process alternative option). Additionally, states can consider RULOF to support the need for alternative compliance options under EG OOOOc in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Comment: Commenters (2282- Kinder Morgan, Inc, 2483-INGAA) request that the EPA not adopt the currently proposed standard of 3 scfm because that standard is unsupported. The BSER determination upon which this standard is based contains no data whatsoever to support this purported standard or the cost that would be required to maintain it. If the EPA continues to believe that dry seal centrifugal compressors should be subjected to a standard, it must first obtain data – both on cost and, more importantly, feasibility and reasonableness of the standard itself – to support a proper BSER analysis. Any other approach would be arbitrary and capricious. The commenters add that any requirements adopted should be a work practice standard, where emissions exceeding a defined threshold trigger maintenance or seal replacement, and not an emission rate limitation.

Commenter (2258-MSC) states that the EPA’s volumetric flow rate of 3 scfm is not consistent with manufacturer’s data and further evaluation is needed. The commenter reports that the volumetric flow rate will vary per compressor model and suction pressure. Assuming a suction pressure of 500 to 1,000 pounds per square inch gauge (psig), manufacturer’s maximum seal gas leakage will be at least three-plus times this rate.

Several commenters (2282-Kinder Morgan, Inc, 2305-Williams, 2399-GPA, 2428-API)<sup>28</sup> recommend that EPA wait for more accurate data. However, if the EPA is intent on establishing a dry seal emissions threshold before receiving the Subpart W reports, commenters recommend relying upon the manufacturer’s specified maximum leak rate for a particular unit. A recent review of dry seal leak curves from a major supplier of centrifugal compressors to the natural gas industry indicates that dry seal leakage rates can vary from 2 to 20 scfm per compressor (with 2 seals per compressor), depending on the make, model, and operating suction pressure of the

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<sup>28</sup> 2428-API and 2282-KM support all 2399-GPA comments.

compressor.<sup>29</sup> If the EPA wishes to set one threshold applicable to all dry seal centrifugal compressors within the next year, the commenters recommend that the EPA set the threshold at 10 scfm per primary dry seal in order to allow for sufficient variability among existing dry seal leak rates. One commenter (2305-Williams) adds that since both dry seals on a dry seal compressor are commonly vented to a single vent stack, companies should be permitted to measure the combined flow rate from the common vent stack and divide by two to obtain the flowrate (scfm) vented per dry seal. Commenter (2428-API) adds that, as the Natural Gas STAR report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Response II-10-18: In response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach and performance-based volumetric flow rate per seal standard/presumptive standard for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble.

The EPA has also made clarifying changes to the final NSPS OOOOb and EG OOOOc regulatory text to clearly indicate that the standard is on a per seal basis. For details, please see discussion in section XI.G.3 (Clarification that the standard is based on a per-seal basis) of the final rule preamble.

Comment: Several commenters (2258 MSC, 2282-Kinder Morgan, Inc, 2305-Williams, 2366-Berkshire Hathaway Energy Company (BHE), 2399-GPA, 2428-API, 2483-INGAA)<sup>30</sup> request clarification that the volumetric standard applies to each seal and not each compressor and that the rule text clearly address manifolded vents on a combined basis to reflect this. The commenters cite the precedent set by the CARB where wet seal compressors in California are restricted to 3 scfm per seal, and not per compressor as set forth in 17 CCR § 95668 (as discussed for wet seal compressors under section 10.2.1 of this Chapter).

Commenter (2282-Kinder Morgan, Inc) notes that the EPA's preamble discussion, and at least some of the proposed rule text, imply that the emissions rate would be on a per-seal basis, and the commenter understands this to be the EPA's intent. The commenter asserts that it is important (as discussed for wet seal compressors under section 10.2.1 of this Chapter) that the EPA's final rule more clearly reflect this intent. Specifically, according to commenter (2428-API), the proposed text provided in 40 CFR 60.5380b or 40 CFR 60.5385b(a), does not provide the distinction that the limits are per seal. It would be impractical for a compressor with multiple seals (centrifugal) to operate the same as compressor with only a single seal. Further, the commenter adds that, as the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Commenter (2282-Kinder Morgan, Inc) (and supported by commenter 2428-API) states that the rule language must more clearly address manifolded vents on a combined basis. The commenter

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<sup>29</sup> Solar Turbines, Emissions from Centrifugal Compressor Dry Gas Seal System, PIL 251 Revision 1 (May 22, 2020).

<sup>30</sup> 2428-API and 2282-KM support all 2399-GPA comments.



states that the Supplemental Proposed NSPS preamble provides that the manifolded wet and dry seal flow rate must be “less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode).”<sup>31</sup> The commenters support this approach, as it reflects the practicalities of measuring emissions from manifolded seals. The commenters also note that the approach is supported by the 2006 Natural Gas STAR report, which states that emissions rates from two seal systems would be double the emissions from a single seal system.<sup>32</sup>

Commenter (2282-Kinder Morgan, Inc) states that it appears that this concept of multiple seals manifolded to one vent is intended to be captured in the proposed regulations at 40 CFR 60.5380b(a)(5)(i)–(ii), 60.5415b(d)(2), 60.5392c(a)(2)(i)–(ii) and 60.5415c(c)(1). However, the proposed regulatory sections addressing the actual volumetric flow rate requirement do not clearly incorporate the preamble concept of multiplying the emissions rate by the number of manifolded seals. Proposed 40 CFR 60.5380b(a)(4)(i) and 60.5392c(a)(1) provide that the volumetric flow rate must not exceed 3 scfm, but they do not mention manifolded seals. Likewise, proposed 40 CFR 60.5415b(d)(2) and 60.5415c(c)(1), pertaining to demonstrating compliance, do not mention manifolded seals either. The commenter notes that the lack of regulatory text on manifolded seals makes it difficult for operators to rely on the preamble text alone. Moreover, they note that, for internal compliance processes, operators do not always cross-reference the preamble pertaining to each regulatory provision.

Several commenters (2282-Kinder Morgan, Inc, 2305-Williams, 2428 API, 2483-INGAA) provide suggested regulation text changes that would clarify the intent of the Supplemental Proposed NSPS preamble to allow for grouping of manifolded wet and dry seal vents where an emissions rate limit is applicable to such seals and that the emissions rate standard is on a per-seal basis. The commenters provide suggested changes that parallel what was provided for similar comments on wet seal compressors (that would also apply for dry seal compressors) under section 10.2.1 of this Chapter. The recommended changes that are detailed under section 10.2.1 of this Chapter would clarify the allowance for grouping of manifolded wet and dry seal vents where an emissions rate limit is applicable to such seals, and make clear that the emissions rate standard is on a per-seal basis.

Response II-10-19: In response to comments received on the December 2022 Supplemental Proposal, the EPA has made clarifying changes to the final NSPS OOOOb and EG OOOOc regulatory text to clearly indicate that the standard is on a per seal basis. For details, please see discussion in section XI.G.3 (Clarification that the standard is based on a per-seal basis) of the final rule preamble.

Comment: Several commenters (2212-Union of Concerned Scientists (UCS), 2249-National Association of Clean Air Agencies (NACAA), 2256-Mille Lacs Band of Ojibwe, 2433-EDF et al) support setting methane and VOC standards for dry seal centrifugal compressors.

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<sup>31</sup> 87 Fed. Reg. at 74,790, 74,792.

<sup>32</sup> EPA, *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*, at 2 (Oct. 2006), [https://www.epa.gov/sites/default/files/2016-06/documents/11\\_wetseals.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/11_wetseals.pdf) (stating that “dry seals leak at a rate of 0.5 to 3 scfm across each seal (1 to 6 scfm for a two-seal system)”).

Response II-10-20: This is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2258-MSC) states that dry seal centrifugal compressors typically consist of a primary and secondary seal which use natural gas. In addition, the assembly has a buffer seal which uses air. The commenter requests that the EPA verify/clarify that measurement of air from the buffer seal is not required.

Response II-10-21: The commenter is correct that the intent of the rule is to not include the measurement of air from the buffer seal.

Comment: Commenter (2258-MSC) states that the EPA needs to expand its cost analysis. Estimated cost for repair is noted as \$15,000 per year. Parts and labor for a seal repair can range from \$100,000 to \$150,000. The commenter adds that an aggressive volumetric flow rate requirement may significantly increase the frequency of required repairs. In addition, the regulatory supplement assumes a typical repair will correct the volumetric flow rate. The commenter recommends that other options be available.

Response II-10-22: In response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach and performance-based volumetric flow rate per seal standard/presumptive standard for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble. In direct response to the comment, the EPA believes that if a repair is needed where the cost is in the range cited by the commenter, there are likely issues well beyond a seal leak that need to be addressed to ensure proper operation of the compressors. Such necessary repairs cannot be attributed to the regulation, even if the testing is what identifies the major issue.

Comment: Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2399-GPA, 2428-API, 2483-INGAA)<sup>33</sup> state that the EPA should not adopt the currently proposed dry seal standard of 3 scfm (per seal) because that standard is unsupported and not adequately justified. Specifically, two commenters (2282-Kinder Morgan, Inc, 2483-INGAA)<sup>34</sup> state that the EPA must first obtain data – both on cost and, more importantly, feasibility and reasonableness of the standard itself – to support a proper BSER analysis.<sup>35</sup> Any other approach would be arbitrary and capricious. The commenters cite three main concerns with the BSER determination:

- 1) The BSER determination contains no data whatsoever to support this purported standard or the cost that would be required to maintain it. The commenters dispute the appropriateness of reliance on §95668(d)(4-9), California’s Regulations<sup>36</sup> for Greenhouse Gas Emission

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<sup>33</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>34</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>35</sup> For example, EPA has recently proposed to require measurements for dry seal compressors under the GHGRP, proposed “Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule,” 87 Fed. Reg. 36,920, 36,974 (June 21, 2022). If EPA finalizes that requirement, it would start collecting data for dry seal emissions.

<sup>36</sup> [https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf](https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf).

Standards for Crude Oil and Natural Gas Facilities to support the standard. Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. According to the commenters, there are no data in the California rulemaking supporting any numeric standard for dry seals, much less a specific rate of 3 scfm. The commenters note both issues with the information/data (outdated or lack of data) used, and the record as provided in the Supplemental Proposal.

- 2) The BSER determination does not consider data that seal emission rate is a function of compressor size and suction pressure, and consequently, the standard should does not properly account for compressor size; and
- 3) The record is also devoid of any information (or data) indicating that proper maintenance and repair could reduce such compressors' dry seal emissions rate to 3 scfm or less, or any information regarding the associated costs of doing so.

The commenters (2282-Kinder Morgan, Inc, 2483-INGAA) state that there is better data available which should be reviewed and analyzed prior to setting a standard.

Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2399-GPA, 2428-API)<sup>37</sup> note that the emission threshold appears to be based on §95668(d)(4-9), California's Regulations<sup>38</sup> for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities which uses a severely limited number of outdated dry seal measurements. This data is referenced in the EPA's Natural Gas Star report, "Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors" (2006), and in Annex Tables 3.6-2 and 3.6-6 supporting the EPA's, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020." This underlying data dates back to 1996 (EPA/GRI study<sup>39</sup>) with few studies being performed since 2000. The commenters assert that the EPA should not rely on such stale data to establish an emission threshold as it is neither accurate nor representative of dry seal centrifugal compressors.

Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2483-INGAA)<sup>40</sup> state that the record of the California rulemaking includes no measured data at all. The basis of the California statement that dry seals have an average emission rate of 3 scfm is merely an EPA natural gas STAR document,<sup>41</sup> but that document is also devoid of any information providing adequate support for the 3 scfm rate cited by CARB staff. Further, the California regulation, which chose not to regulate dry seal units, but reported a typical dry seal emission rate as the basis for an alternative, optional standard for centrifugal compressors with wet seals. In identifying 3 scfm as the alternative limit for wet seal units, the California regulation cited an EPA Natural Gas STAR Lessons Learned document that provided limited information from a European company not representative of the prevalent centrifugal compressors in U.S. natural gas operations. In

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<sup>37</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>38</sup> [https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf](https://ww2.arb.ca.gov/sites/default/files/2020-03/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf).

<sup>39</sup> Methane Emissions From the Natural Gas Industry, Volume 2: Technical Report EPA-600 /R-96-C80b (June 1996).

<sup>40</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>41</sup> EPA: Lessons Learned from Natural Gas STAR Partners, "Replacing Wet Seals with Dry Seals in Centrifugal Compressors" (Oct. 2006), [https://www.epa.gov/sites/default/files/2016-06/documents/ll\\_wetseals.pdf](https://www.epa.gov/sites/default/files/2016-06/documents/ll_wetseals.pdf) (hereinafter "Lessons Learned from Natural Gas STAR Partners").

addition, the natural gas STAR program did not include quality control elements to verify emissions estimates, so use of such data as the sole basis for an NSPS standard is not adequate.

According to the commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2483-INGAA)<sup>42</sup>, the [Natural Gas STAR] document only provides, as a basis for this purported “average” rate for dry seals, a chart of estimated dry seal emission rates from a vendor that generally does not serve U.S. markets and is primarily associated with liquid pump products – not the natural gas compressor drivers that serve the U.S. transmission and storage markets. In short, the dry seal emission estimate in the 2006 natural gas STAR document is not based on any actual measured rates; just supposition upon supposition based on inapplicable data from a foreign manufacturer.

Commenters (2282-Kinder Morgan, Inc, 2483-INGAA)<sup>43</sup> add that California presumes the 3 scfm rate would be the average emission rate for well-maintained dry seals, as the EPA seems to acknowledge.<sup>44</sup> Therefore, some well-maintained dry seals will have an inherently higher rate than 3 scfm, and there is no evidence or even a suggestion in the record that proper maintenance would be sufficient to bring such a rate down to 3 scfm. Identifying an “average” rate as the basis for a standard is flawed, especially when data ranges associated with the average are not discussed nor their relevance analyzed. The commenter suggests that an average value should not serve as the basis for the standard unless its validity is clearly supported.

Commenters (2366-BHE, 2428-API) state that the dry seal emission standard does not properly account for compressor size and has not considered data that seal emission rate is a function of compressor size and suction pressure. According to commenter (2428-API), larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations. According to commenter (2366-BHE), information available from the primary manufacturer of transmission and storage segment turbines in the U.S. shows that dry seal emission rates are a function of compressor type (e.g., size) and operating (suction) pressure. For the transmission and storage segment, the majority of turbines are manufactured by Solar Turbines, and a Solar PIL presents emissions as a function of compressor suction pressure for different units. The PIL also explains dry seal technology. The U.S. manufacturer data clearly shows that 3 scfm will be exceeded during standard operations for many units and/or at many suction pressures that are common on transmission systems.

Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2483-INGAA)<sup>45</sup> state that the EPA has erroneously concluded that maintenance alone can ensure that a 3 scfm flow rate can be met. The commenters state that the record is devoid of any information whatsoever indicating that proper maintenance and repair could reduce such compressors’ dry seal emissions rate to 3 scfm or less, or any information regarding the associated costs. Commenter (2366-BHE) states that in the Technical Support Document (TSD), the EPA assesses maintenance costs (without support

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<sup>42</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>43</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>44</sup> [Id.]

<sup>45</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

for the assumed value) but provides no evidence or documentation to support a conclusion that dry seal emissions exceed 3 scfm when poorly maintained units or due to anomalous operations. In simple terms, the EPA makes assumptions with no technical support. The commenter adds that the EPA provides no information or data to support its assertion that maintenance or repair will lower emissions below that threshold for larger units and/or higher-pressure applications. This assertion is false based on available information (e.g., Solar PIL).

Commenters (2282-Kinder Morgan, Inc, 2483-INGAA)<sup>46</sup> states that there is no evidence anywhere – and certainly not in the California rulemaking – supporting the assumption that the emission rate of a dry seal fluctuates much or is susceptible to increasing because of lack of maintenance or repair. Because of the inherent design of a dry seal, the emission rate of a dry seal “is what it is” and it is much less than the very high emission rates (more than 50 scfm) that purportedly have been measured in the past for some wet seal compressors. The incentives for proper maintenance (or, more likely, replacement) exist regardless of whether these compressors are subject to a numeric standard or not. For example, Solar Turbines, the primary manufacturer of transmission and storage compressors used in the U.S., includes in some of its models an onboard operational control system to track seal health (primarily through pressure measurements). Owners have a strong incentive to follow Solar’s recommendations to replace the dry seal when measurements indicate a necessity to do so. The commenter states that where a dry seal has failed and is emitting at a rate materially higher than its inherent, design rate, the only maintenance and repair action available is to replace the seal, likely at a cost of \$100,000 or more.<sup>47</sup> Moreover, depending on the size of the compressor and the line pressure, no amount of maintenance, repair, or replacement will be sufficient to reduce the emissions rate of some dry seal compressors to 3 scfm (or any other unsupported level, unless that level was high enough to cover all well-functioning dry seals).

Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2428-API, 2483-INGAA)<sup>48</sup> note that more reliable information and data are available that could be used in developing a dry seal emission standard. Commenter (2428-API) states that based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.<sup>49</sup> The commenter does not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2 of the commenter’s letter provides more details on their short analysis showing variable sizes of both dry and wet seal compressors as reference. [Table 2. Variation in Compressor Driver Output as Reported under the EPA’s greenhouse Gas Reporting Program for Calendar Year 2021]

Several commenters (2282-Kinder Morgan, Inc, 2366-BHE, 2483-INGAA)<sup>50</sup> state that for transmission and storage, the majority of turbines are manufactured by Solar Turbines. The

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<sup>46</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>47</sup> A recompression system, which may be needed in some instances, would cost in excess of \$500,000.

<sup>48</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

<sup>49</sup> Information was extracted from EPA’s Envirofacts database using the GHG query builder: <https://enviro.epa.gov/query-builder/ghg>.

<sup>50</sup> 2282-KM noted in their comments that they support all 2483-INGAA comments.

commenters suggest that the Solar Turbine PIL<sup>51</sup> be considered as a superior reference compared to the Gas STAR document. Information available from Solar shows that dry seal emission rates are a function of compressor type (e.g., size) and operating (suction) pressure. The PIL also explains dry seal technology. The PIL provides data plots for a range of compressor sizes and suction pressures. The U.S. manufacturer data clearly shows that 3 scfm will be exceeded during standard operations for many units and/or at many suction pressures that are common on transmission systems. Since that data shows higher emission rates for many applications, it alone refutes the basis of the EPA's proposed 3 scfm emission rate. According to the commenters, if the EPA insists on proceeding with a standard for dry seal compressors at this time, that standard may have to be variable and a function of the operating conditions for the seal (i.e., unit size and suction pressure); or, if the standard is a single emission rate, it must be high enough to address the largest units and highest suction pressures in natural gas operations.

As a result of these concerns, several commenters provided recommendations to the EPA for development of a dry seal emission standard. Commenter (2366-BHE) offers their support to assist the EPA in developing a reasonable work practice standard for dry seal centrifugal compressors.

- Commenter (2428-API) states that the EPA should supplement the docket with information to support why the proposed value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).
- Commenters (2282-Kinder Morgan, Inc, 2399-GPA, 2428-API)<sup>52</sup> recommend that the EPA postpone establishing any type of quantitative threshold for dry seal centrifugal compressors until after it finalizes amendments to the Subpart W reporting rule. See 87 Fed. Reg. 36,920 (June 21, 2022) (proposed rule). Once implemented, the commenters contend that the EPA will have thousands of data points to give a more accurate dry seal centrifugal compressor measurements that can be used for a subsequent emissions threshold.
- Commenters (2282-Kinder Morgan, Inc, 2399-GPA, 2428-API)<sup>53</sup> state that if the EPA decides to re-propose a numeric emission standard for dry seal compressors, it must first identify reliable information about emission rates that are actually achieved by well-maintained dry seal compressors and the maintenance/replacement activity needed to achieve them. Because of the functional dependence on unit size and suction pressure, it is likely that a single emissions rate is not sufficient, unless that rate is high enough to address the largest units and highest suction pressures in natural gas operations.<sup>54</sup> Second, any emission rate standard must be expressed as a per seal standard.<sup>55</sup> If a compressor has more than one dry seal, it cannot possibly meet a standard developed on the basis of data from individual dry

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<sup>51</sup> Solar Turbines Product Information Letter (PIL) 251, "Emissions from Centrifugal Compressor Gas Seal Systems," January 2013 (Attachment C of their Comments). [Attachment C was redacted in full.]

<sup>52</sup> 2428-API and 2282-KM support all 2399-GPA comments.

<sup>53</sup> 2428-API and 2282-KM support all 2399-GPA comments.

<sup>54</sup> INGAA also believes EPA should investigate whether the types of onboard sensors that Solar Turbines provides with some of its models are prevalent in the industry. If that is the case, these sensors – even if they do not measure emission rates specifically, may be adequate to provide information about the health of the dry seals, possibly supporting a standard requiring seal replacement as recommended by the manufacturer.

<sup>55</sup> The source information cited by EPA (the California regulation and EPA natural gas STAR document) clearly indicate this is an emission rate per seal, as does the Solar Turbines PIL. If a dry seal emission rate threshold is retained in the final rule, it should be clearly indicated that the rate applies on a per seal basis.

seals. Finally, if the standard would require yearly measurements and monitoring of these compressors for the first time, as the current proposal does, the cost of monitoring<sup>56</sup> would be part of the proposed standard and should be accounted for in the BSER analysis.

- Commenter (2366-BHE) notes that, in principle, they do not object to a standard for dry seal compressors. The commenter states the EPA should: (1) recognize that 3 scfm is an approximate average rate for some dry seal compressors, but it is not characteristic of units that may have an emission rate several times higher – e.g., large compressors with relatively high suction pressure); (2) consider the upper end range or tiered emission rates in the standard; (3) conduct analysis and consider cost effectiveness of installing a seal vent recovery / control system if the emission rate cannot be met; (4) account for the cost of additional monitoring a numeric standard would require; (5) clarify that the selected standard applies for each dry seal, not for the entire compressor; and (6) if a standard is retained (considering the factors above), propose a work practice standard and define the schedule for operators to resolve the issue when a unit exceeds its defined emission rate threshold.

Response II-10-23: In response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach and performance-based volumetric flow rate per seal standard/presumptive standard for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) and section XI.G.2 (Numeric standard versus work practice standard) of the final rule preamble.

### **10.3 Emission Guidelines OOOOc Designated Facility/Definitions**

[**Note:** Comments provided in section 10.1 of this Chapter on NSPS OOOOb affected facility/definitions also apply to EG OOOOc designated facilities/definitions.]

### **10.4 EG OOOOc Proposed BSER**

[**Note:** BSER comments (and EPA's response to comments) that apply to both the proposal for NSPS OOOOb and EG OOOOc are presented in section 10.2 of this Chapter. Below are comments and EPA's responses to comments that were specifically provided for EG OOOOc.]

Comment: Commenter (2282-Kinder Morgan, Inc) supports the December 2022 EG OOOOc proposed approach for establishing a defined emissions flow rate rather than the 95.0 percent reduction of methane emissions that was based on the impractical and potentially dangerous BSER of routing emissions to a control device or process. The commenter supports the change in approach based on the feasibility and safety concerns discussed in the December 2022 Supplemental Proposal.

Response II-10-24: With regards to support for EPA's December 2022 EG OOOOc proposed approach for establishing a defined emissions flow rate rather than the 95.0 percent reduction of

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<sup>56</sup> For example, a flow meter is estimated to cost upwards of \$10,000 and installation also costs upwards of \$10,000.

methane, this is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2218-TCEQ) states that the proposed requirements for several types of designated facilities are economically unreasonable and should be revised. They state as an example that the model rule requires a capture and 95.0 percent effective control system for centrifugal compressors to “central production sites” regardless of their seal configuration.

Response II-10-25: The final EG OOOOc model rule includes capture and 95 percent control of emissions for centrifugal compressors to provide owners and operators an alternative compliance option in lieu of meeting the performance-based volumetric flow rate standards and is not required. Additionally, states can consider RULOF to support the need for alternative compliance options under EG OOOOc in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Comment: Commenter (2258-MSD) states that the compliance alternative of EG OOOOc, the requirement to reduce emissions, should note a reduction of 95 percent or less than the presumptive standard. The commenter recommends incorporating the following language (underlined text is new text and struck out text is deleted text):

an owner or operator of a centrifugal compressor equipped with wet seals can comply with EG OOOOc by reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent, which or achieves emission reductions resulting in emissions less than ~~greater than~~ or equal to the 3 scfm proposed presumptive standard.

Response II-10-26: While the EPA appreciates the concept put forth by the commenter, the implementation of such an alternative is problematic. For instance, in order to establish the reduction achieved by the 3 scfm standard, it would be necessary for the owner or operator to establish the baseline from which the reduction would be measured. The commenter did not recommend a process for the establishment of a baseline, but the EPA would anticipate that such a process would be burdensome and fraught with complications and issues. Therefore, the commenter’s suggestion was not incorporated in the final rule.

Comment: With regards to 40 CFR 60.5392c(a)(3) which includes the option to reduce methane emissions by 95.0 percent by routing to a control device or process, commenter (2282-Kinder Morgan, Inc) requests that EPA refer to their November 2021 proposal comments, dated January 31, 2022 (included as Exhibit B in their December 2022 proposal comment letter), where they express concerns regarding the safety, feasibility, and cost as it relates to routing a seal to control or process. The commenter supports a volumetric flow rate BSER. For the reasons discussed in the comments they submitted on the November 2021 proposal, the commenter opposes a BSER for wet and dry seals that would require reducing emissions from the seal by 95.0 percent reduction by routing to control or process. The commenter states that they recognize that the EPA presents this as an alternative to the volumetric flow rate, however, the commenter does not



believe these are feasible, or cost-effective, alternatives that should be reasonably drafted into a rule.

Response II-10-27: In response to the comment that EPA should not, even as an alternative to the performance-based volumetric flow rate standard, include the option to reduce emissions from seals by 95.0 percent by routing to control or a process, we disagree. Although the commenter may not opt to comply with this option because of feasibility or cost-effectiveness, that is not a reason to not provide these alternative options to other owners or operators that may find these options more attractive.

Comment: Commenter (2317-Alaska Oil and Gas Association (AOGA)) requests that the EPA revise the proposed EGs for existing wet seal centrifugal compressors to address the characteristics of the wet seal compressors deployed in Alaska oil production operations.

Commenter (2317-AOGA) reports that their members use wet seal compressors at their ANS and Cook Inlet production fields to increase the pressure of residual gas captured in production operations to enable delivery to gas processing plants and/or re-injection into well fields. There are about 40 compressor trains on the ANS installed for this purpose. The compressors in use on the ANS were installed in the late 1970s through mid-1980s and have not been modified or reconstructed. They range in size from 15,140 hp to 53,665 hp. None are currently subject to NSPS OOOO or NSPS OOOOa.

The commenter (2317-AOGA) states that all the wet seal centrifugal compressors in Alaska are equipped with a seal oil gas separation system that separates gas from the sour seal oil exiting the compressor seal assembly, upstream from the degassing drum. On the ANS the gas captured in the seal oil trap is routed to various outlets for use as turbine fuel, low pressure fuel gas, compressor suction, flare purge or to flare (for destruction). In Cook Inlet the gas is processed for delivery to market. The commenter notes that the EPA described this technology enthusiastically in the 2014 Natural Gas STAR Report. Sour seal oil passes through a “seal oil trap,” a type of separator, prior to routing to the seal oil degassing drum. The commenter notes that they described the seal oil traps in their comments on EPA’s 2021 proposal.<sup>57</sup> Attachment B<sup>58</sup> of the commenter’s letter resubmits that information, including a process flow diagram of the seal oil recovery system on an ANS wet seal compressor. The commenter notes that the EPA’s 2014 Natural Gas STAR report praises the seal gas recovery system deployed on the ANS as “highly effective at capturing degassing emissions from wet seal centrifugal compressors . . .”<sup>59</sup>

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<sup>57</sup> Letter of January 31, 2022, from Kara Moriarty to Karen Marsh (“2022 AOGA Comments”) at 10-12, Docket OAR-2021-0317-0916.

<sup>58</sup> Attachment B - Re-submittal of Alaska Oil and Gas Association comments "Proposed New Source Performance Standards and Emissions Guidelines for Control of GHG Emissions from the Oil and Natural Gas Sector, Docket ID No. EPA-HQ-OAR-2021-0317", dated January 31, 2022. (Attachment B).

<sup>59</sup> 2014 Natural Gas Star Report at 5. Page 5 of 11.

The commenter (2317-AOGA) also provides the following:

- Careful review of the CARB support document sources provides no support for the EPA’s proposed finding that preventive maintenance and repair will enable compliance with a 3 scfm flow limit at wet seal compressor seal vents.<sup>60</sup>
- The current NSPS Subpart OOOO and Subpart OOOOa require 95.0 percent control efficiency for VOCs (not methane) from new and modified wet seal compressors,<sup>61</sup> but neither standard includes a volumetric flow limit. Neither standard provides support for a 3 scfm flow limit as a “demonstrated” system of emission reduction for control of VOC and methane emissions from existing wet seal compressor vents.
- One document CARB cited is a 2014 EPA report on the use of seal oil traps to capture and recycle seal oil and entrained gas.<sup>62</sup> The 2014 EPA report contains no data supporting the feasibility of meeting a 3 scfm flow limit per seal from the degassing system vents. To the contrary it finds that gas volume from degassing centrifugal compressor seal oil varies due to site-specific features of each compressor.<sup>63</sup>
- A 2006 Natural Gas STAR report recommended the replacement of wet seals with dry seals. That report estimated that wet seals emit 50 scfm per seal, but dry seals emit only 3 scfm.<sup>64</sup> CARB based its 3 scfm wet seal flow limit on the estimated dry seal emission rate, explaining that the 3 scfm limit is “similar to” the NSPS 95.0 percent control efficiency requirement for new wet seal compressors.<sup>65</sup>
- The CARB Staff Report cites data collected in the 2007 CARB Oil and Gas Survey as support for its 3 scfm flow limit. That survey included 47 centrifugal compressors, but CARB did not request data on the size of the compressor, and the report does not differentiate between wet and dry seal designs.<sup>66</sup> The CARB Staff Report noted that there was only one uncontrolled wet seal centrifugal compressor operating in California at the time of the 2007 CARB survey.<sup>67</sup> The feasibility of meeting the 3 scfm flow limit at that one compressor may not have carried much weight in the development of the 3 scfm flow limit. CARB proposed as a compliance option to give the owner of the last uncontrolled compressor in California extra time to replace wet seals with dry seals by the compliance deadline, “if controlling the emissions with the use of a vapor collection system is not possible.”<sup>68</sup>
- Information provided to the EPA during the comment period on the 2021 proposal suggests that no wet seal compressor currently meets Subpart OOOOa capture and control requirements. Kinder Morgan explained that none of its 197 wet seals have been modified to trigger the 95.0 percent control standard, that Kinder Morgan’s practice for new compressors is to install dry seal units, and that at least one compressor

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<sup>60</sup> 87 Fed. Reg. at 74791.

<sup>61</sup> 40 CFR 60.5380(a)(1); 40 CFR 60.5380a(a)(1).

<sup>62</sup> EPA, Wet Seal Degassing Recovery System for Centrifugal Compressors (2014) at 3 (“2014 Natural Gas Star Report”), Attachment A to these comments.

<sup>63</sup> Id.

<sup>64</sup> EPA, Replacing Wet Seals with Dry Seals in Centrifugal Compressors (2006) at 3.

<sup>65</sup> CARB Staff Report at 100. Page 3 of 11.

<sup>66</sup> CARB, 2007 Oil and Gas Industry Survey Results, Final Report (Revised), Chapter 15 (October 2013).

<sup>67</sup> CARB Staff Report, Initial Statement of Reasons at 99.

<sup>68</sup> Id. at 100.

manufacturer questioned the safety of capturing and flaring emissions from a wet seal compressor degassing vent.<sup>69</sup>

- The experience of the commenter's members echoes the Kinder Morgan's comments. No ANS wet seal compressors have been installed or modified since adoption of the Subpart OOOO control requirements. The practice of ANS operators has been to install dry seal compressors when a new compressor is necessary. The EPA cited Kinder Morgan's comments to support its decision in the current proposal to shift its presumptive BSER recommendation for existing wet seal compressors from 95.0 percent control to a flow limit.<sup>70</sup> But the 3 scfm limit in the CARB standard assumes the same 95.0 percent control efficiency assumption that is unproven in practice for wet seal compressors.

In summary, the commenter (2317-AOGA) states that:

- The EPA candidly acknowledges that CARB developed the 3 scfm emission standard for wet seal compressor vents "because this was the equivalent to an average dry seal emission rate."<sup>71</sup>
- The three resources that CARB staff considered in developing the 3 scfm flow limit provide no support for the feasibility of meeting that limit at wet seal compressor vents.
- The EPA offers no other data supporting the viability of meeting a 3 scfm flow limit on a wet seal compressor vent through preventive maintenance and repair.
- The EPA offers no evidence that any wet seal compressor vent currently complies with CARB's 3 scfm flow limit. Even if one such compressor could be found, it would not support the 3 scfm flow limit because the flow rate from a wet seal compressor degassing drum varies broadly based on site-specific factors.
- The EPA concedes that it lacks "specific costs" for the maintenance and repair activities needed to meet 3 scfm.<sup>72</sup> But these acknowledgments understate the challenge of demonstrating that a well-maintained wet seal compressor can meet a 3 scfm flow limit per seal vent.

The commenter (2317-AOGA) supports the concept of adopting a volumetric limit based on diligent maintenance and repair as BSER for control of emissions from wet seal compressor vents. But the 3 scfm limit in the proposal is not based on data from wet seal compressors, and that limit.

The comment (2317-AOGA) supports the concept of adopting a flow limit based on maintenance and repair as BSER for control of emissions from wet seal compressor vents. That option avoids the safety risks, engineering challenges and extravagant cost of capturing and flaring low volume, low pressure vent streams. The problem with the EG OOOOc proposal is that the 3 scfm proposed limit does not account for variability in the size and configuration of wet seal compressors within the source category and is not demonstrated or achievable for wet seal

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<sup>69</sup> Comments of Kinder Morgan Inc. on EPA Proposed Standards and Emissions Guidelines for the Oil and Natural Gas Sector at 8, 13-14, Docket ID No. EPA-HQ-OAR-2021-0317-1375 ("Kinder Morgan Comments").

<sup>70</sup> 87 Fed. Reg. at 74791.

<sup>71</sup> 87 Fed. Reg. at 74785. Page 4 of 11.

<sup>72</sup> 87 Fed. Reg. at 74785-86.

compressors of the size and configuration of those deployed in oil and gas production operations in Alaska.

Response II-10-28: The EPA has made revisions to the final rule to address some of the commenter's concerns regarding their particular centrifugal compressors equipped with wet seals in the final rule (see below). While the EPA notes that it does not have sufficient information to establish separate performance-based volumetric flow rate work practice standards based on every size and configuration of centrifugal compressor equipped with wet seals, the EPA has received a lot of support from industry for proposing the 3 scfm per seal performance-based volumetric flow rate work practice standard as a compliance option in lieu of having to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent by routing emissions via a closed vent system (CVS) to a control device, or by routing emissions via a CVS to a process for existing sources. Nonetheless, the compliance options to route emissions to a control device or process are maintained in the final EG OOOOc presumptive standards. In addition, states can consider remaining useful life and other factors (RULOF) to support the need for an alternative performance-based volumetric standard for wet seal centrifugal compressors in their state plans. See section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).<sup>73</sup>

See Section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the preamble to the final rule responds to comments on the commenter's concerns that their centrifugal compressors cannot meet a 3 scfm per seal performance-based volumetric flow rate.

See also section XI.G.2 (Numeric standard versus work practice standard) of the final rule preamble that discusses EPA's decision to revise the format of the volumetric flow rate per seal performance standard for compressors equipped with wet seals to be implemented as a work practice standard and not a numeric limit where an exceedance would be considered a violation.

Comment: Commenter (2317-AOGA) would support the designation of seal oil traps as an EG OOOOc compliance option for Alaska wet seal compressors. For several reasons, however, Alaska wet seal compressors equipped with seal oil traps do not uniformly meet the proposed 3 scfm limit. The volume of seal oil slip from a wet seal compressor correlates with compressor shaft size, pressure and speed. Alaska wet seal compressors span a broad range of capacities, and the degassing drums serving the larger units vent higher volumes of seal gas. Attachment C <sup>74</sup>to their comments provides a table showing flow rate data from 27 wet seal compressor degassing vents sampled by AOGA member Hilcorp for the EPA GHG emissions reporting. The table shows the flow rate per seal, but a single degassing drum can discharge gas from up to four seal oil traps. The variability in the data reflects the variability in size and configuration of the

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<sup>73</sup> The D.C. Circuit vacated certain timing provisions within subpart Ba. *Am. Lung Assoc. v. EPA*, 985 F.3d 914 (D.C. Cir. 2021), petition for cert. pending, No. 20-1778 (filed June 23, 2021) (*Am. Lung Assoc.*). However, the court did not vacate the applicability provision. Therefore, 40 CFR part 60, subpart Ba, applies to the final EG. In addition, on November 17, 2023, the EPA finalized amendments to subpart Ba that address the provisions that were vacated in 2021 and make other updates to the implementing regulations applicable to this EG.

<sup>74</sup> Attachment C - Table of data titled "Hilcorp Alaska Wet Seal Combustion Turbines, Volumetric Flow Rate Per Seal (2016-2011). (Attachment C).

compressors and the fact that each seal oil trap operates on a discharge cycle, and a degassing drum may receive sour seal oil from up to four different seal oil traps at any moment. Depending on when in the cycle the sample is taken, the per seal flow rate can exceed 3 scfm.

Based on the degassing drum flow rate data summarized in Table 1 (of Attachment C to their comment letter) the commenter (2317-AOGA) proposes a volumetric flow limit for Alaska wet seal compressor vents of 9 scfm of methane and VOCs per seal, multiplied by the number of compressor seals venting through a common stack. For example, they note that a two-stage compressor has four seals (two per stage), all of which are manifolded into one vent to atmosphere. If the per seal flow limit was 9 scfm, the flow limit for the common vent should be 36 scfm.

Response II-10-29: Section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the preamble to the final rule responds to these comments.

Comment: Commenter (2317-AOGA) states that the NSPS OOOOb capture and control requirements for new wet seal compressors are not reasonably achievable for existing compressors in Alaska. The commenter notes that the December 2022 proposed EG OOOOc offers the NSPS OOOOb control options as a fallback for wet seal compressors that cannot meet the presumptive 3 scfm flow limit.<sup>75</sup> But these options would require a cover on the degassing drums, connected through a closed vent system to process or to a control device that achieves a 95.0 percent reduction in emissions, should an existing compressor ever be modified or reconstructed.<sup>76</sup> The commenter states that in Alaska oil and gas production operations there is no cost-effective option to recover degassing drum emissions. Degassing drums vent small volumes of methane and VOCs at atmospheric pressure. They refer to flow rates reported in Attachment C of their comment letter. The volumes are small because the seal oil traps capture and recycle most of the seal gas upstream of the degassing drum. They report that operators would need to install new compression devices to boost degassing drum vent gas pressure to the approximately 20 psi that would enable delivery of those streams to the flare header line. The commenter states that larger new compression devices would be required to boost vent gas to a much higher pressure that would enable delivery to a process line for injection into sub-surface reservoirs.

According to the commenter (2317-AOGA), the combination of low methane and VOC recoveries with high capture costs makes the capture and control alternative very expensive on a cost per ton basis. They note that Kinder Morgan's comments on the 2021 EPA proposal, where they provide that the 95.0 percent reduction requirement is technically infeasible and cost-prohibitive even for wet seal compressors located on natural gas pipelines in the lower 48.<sup>77</sup> For wet seal compressors deployed in Alaska production operations with seal oil traps the cost per ton of covering the degassing drum vents and reducing emissions from those vents by 95.0 percent would be prohibitive.

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<sup>75</sup> 87 Fed. Reg. at 74791.

<sup>76</sup> 87 Fed. Reg. at 74787; proposed § 60.5392c(3)-(4). Page 7 of 11.

<sup>77</sup> Kinder Morgan Comments 8-20.

Response II-10-30: Section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the preamble to the final rule responds to these comments.

Comment: Commenter (2433-EDF et al) states that the EPA should further strengthen the wet seal compressor standards by prioritizing control methods that route captured gas to a process rather than a completion device.

Response II-10-31: While the EPA agrees that routing to a process is a preferred option to routing to a combustion device, there is insufficient evidence to support a hierarchy that prioritizes routing to a process over routing to control. See Response II-10-14 for a response to this comment.

## **10.5 NSPS OOOOb and EG OOOOc Compliance Issues**

### ***10.5.1 Subpart KKK Wet Seal Compressor Requirements***

Comment: Commenter (2222-Wisconsin Department of Natural Resources (WDNR)) recommends that EPA incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants. The commenter states incorporating all the compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants would provide significant clarity and consistency to both state regulators and affected facilities. In addition, the EPA should consider taking this approach for other categories of affected facilities that will be covered by the new NSPS and EG as well as the existing NSPS.

Response II-10-32: The EPA evaluated this option and determined that incorporating compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants in NSPS OOOOb or EG OOOOc was unnecessary. The EPA is instead clarifying applicability of requirements in the final rule preamble and NSPS KKK regulatory text. See discussion in section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa?) of the final rule preamble.

### ***10.5.2 Recommended Work Practice Standard Provisions (Apply to All Centrifugal Compressors)***

Comment: Several commenters (2258-MS, 2282-Kinder Morgan, Inc, 2305-Williams, 2326-American Exploration and Production Council (AXPC), 2399-GPA, 2428-API, 2483-INGAA) assert that the rule should clarify the required compliance obligations, include a repair or replacement timeline, and eliminate avoidable emissions from repair to wet and dry seals. According to the commenters, the proposed NSPS rule is drafted to require an emissions flow rate limit for wet and dry seals. If the individual seal exceeds the 3 scfm (or a group of seals exceeds the applicable threshold), the EPA expects the operator to repair, or replace, that seal, as appropriate.<sup>78</sup> The rule does not describe what is required if the measurement at the seal vent

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<sup>78</sup> See, e.g., 87 Fed. Reg. at 74,711-12 (Table 3).

exceeds the applicable flow rate. The commenters recommend that dry seal centrifugal compressors and self-contained wet seal compressors be regulated through work practice standards. And that the rule provide a proposed timeline for repair or replacements, as well as delay of repair provisions, consistent with nearly all other NSPS drafted by the EPA.

According to commenter (2483-INGAA), the EPA, without any explanation or analysis of the consequences, summarily turned California's work practice standard into an emission rate limitation. There is nothing in the record about what it would technically take, and the associated cost, to meet such a limitation. The commenter states that a delay of repair provision in such a regulatory scheme appropriately recognizes that the unit must be shut down to affect any such repair and replacement and that parts availability and supply chain disruptions may be relevant to how quickly the repair or replacement can be made. In addition, there is nothing in the record to indicate that it is feasible for the source to anticipate that a well-functioning wet seal that meets the 3 scfm limitation one year will exceed it before the next year's test, or the cost of doing so (if possible).

Several commenters (2282-Kinder Morgan, Inc, 2428-API, 2305-Williams, 2399-GPA) suggest that the EPA allow one of the following corrective actions by an operator within two years if the applicable emission threshold is exceeded:

- (1) repair or replace the dry seal, wet seal or internal seal gas recovery system; and
- (2) route emissions from the dry seal vent through a closed vent system or from the degassing vent using a cover and closed vent system a control device; or
- (3) route emissions from the primary dry seal vent through a closed vent system or route the degassing vent using a cover and closed vent system to a process.

The commenters (2282-Kinder Morgan, Inc, 2305-Williams, 2399-GPA, 2428-API) recommend that if an operator cannot complete the corrective action within two years, then a corrective action plan with work scope and alternate schedule be submitted to the EPA under a work-practice-based framework. According to the commenters, two years is a reasonable corrective action period since the corrective actions listed above can require significant planning, scheduling, engineering, and construction. Exceedance of the emissions threshold after two years (in the absence of a corrective action plan), or after the time stated in the corrective action plan, would result in a deviation subject to recordkeeping and reporting requirements similar to other types of compressors.

Commenters (2282-Kinder Morgan, Inc, 2399-GPA) the delay of repair provision is consistent with delay of repair requirements under 40 CFR 60.5397a(h)(3), requiring repair within two years, or the next scheduled shutdown (whichever is earlier) where repairs are technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair. Further, the EPA has taken this approach before in

most if its NSPS regulations.<sup>79</sup> In fact, the EPA has also proposed a delay of repair approach in other contexts of the Proposed NSPS Rule where emissions caused by the repair would exceed the existing leak rate.<sup>80</sup>

Commenter (2282-Kinder Morgan, Inc) proposes 90 days as a reasonable timeframe given the significant variety of repair methods (including replacement) that may be appropriate for these units, as the EPA recognizes in its preamble.

Commenters (2282-Kinder Morgan, Inc, 2483-INGAA) propose revisions to regulatory language to implement the requested work practice approach and delay of repair provision.

The following revised rule language is proposed by commenter (2282-Kinder Morgan, Inc) for dry and wet seals in the proposed new 40 CFR 60.5392c(d) and redesignating the existing paragraph (d) as paragraph (e) (underlined text is new text and struck out text is deleted text):

(d) If the results of the initial (§60.5410c(c)) or continuous (§60.5415c(c)) compliance measurement demonstrate that the wet or dry seal emissions flow rate is greater than 3 scfm, you must repair or replace the wet or dry seal within 90 days from the date of the initial or continuous flow rate measurement.

(1) If the repair or replacement is technically infeasible, would require a vent blowdown, a process unit or facility requires shutdown, parts or materials are unavailable, or it would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled process unit or facility shutdown for maintenance, after a scheduled vent blowdown, or within 2 years, whichever is earliest. For purposes of this paragraph (d)(1), a vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

~~(e)~~ You must perform the reporting as required by §60.5420c(b)(1) and (4) and (b)(10) through (12), as applicable, and the recordkeeping as required by §60.5420c(c)(3) and (c)(7) through (12), as applicable. The following revised rule language is proposed by commenter (2483-INGAA) for dry and wet seal compressors:

*40 CFR 60.5392c(a) and 60.5380b(a):*

*Recommended 40 CFR 60.5392c(a)(1) and (a)(1)(iii) changes (underlined text is new text and struck out text is deleted text):*

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<sup>79</sup> See, e.g., 40 C.F.R. §§ 60.482-9(c)(1) (delay of repair allowed if emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair), 60.5416(b)(10) (delay of repair permitted if emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair).

<sup>80</sup> See, e.g., proposed § 60.5400b(h)(6)(ii)(A) (Delay of repair showing requires in part “that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair.”).



(1) You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. If the volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceeds 3 standard cubic feet per minute (scfm) multiplied by the number of wet seals connected to the vent, the wet and dry seals connected to the measured vent must be repaired as provided in paragraph (a)(1)(iii) of this section.

[...]

(iii) The seal repair must be conducted no later than the next scheduled compressor station shutdown for maintenance. Delay of repair beyond the next compressor station shutdown for maintenance is allowed for a centrifugal compressor wet and dry seal, if seal replacement is necessary during the compressor station shutdown for maintenance, seal supplies have been depleted, and seal supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next compressor station shutdown for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance. You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section within 15 days after the repair to document that the rate has been reduced to less than 3 scfm per seal.

Recommended *40 CFR 60.5392c(a)(2)(i)* changes (struck out text is deleted text):

(i) For centrifugal compressor dry or wet seal vents in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry or wet seal vent using one of the methods specified in paragraphs (a)(2)(i)(A) through (C) of this section. ~~If there is more than one dry seal compressor or wet seal compressor seal vent, determine the aggregate centrifugal compressor dry or wet seal vent volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for each dry seal compressor or wet seal compressor vent on the compressor.~~

Recommended *40 CFR 60.5380b(a)(4)(i)* changes (underlined text is new text and struck out text is deleted text):

(i) ~~The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm).~~ You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section. If the volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, exceeds 3 standard cubic feet per minute (scfm) multiplied by the number of wet seals connected to the vent, the seals connected to the measured vent must be repaired as provided in paragraph (a)(6) of this section.

Recommended new paragraph *40 CFR 60.5380b(a)(6)* (underlined text is new text):

(6) The seal repair must be conducted no later than the next scheduled compressor station shutdown for maintenance. Delay of repair beyond the next compressor station shutdown for maintenance is allowed for a centrifugal compressor wet and dry seal, if seal replacement is necessary during the compressor station shutdown for maintenance, seal supplies have been depleted, and seal supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next compressor station shutdown for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance. You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section within 15 days after the repair to document that the rate has been reduced to less than 3 scfm per seal.

Recommended changes to *40 CFR 60.5380b(a)(5)(i)* (struck out text is deleted text):

(i) For centrifugal compressor dry seal vents or self-contained wet seal centrifugal compressor in operating-mode or in standby-pressurized-mode, determine volumetric flow rate at standard conditions from each dry seal vent or self-contained wet seal centrifugal compressor using one of the methods specified in paragraphs (a)(5)(i)(A) through (C) of this section. ~~If there is more than one dry seal vent or self-contained wet seal centrifugal compressor, determine the aggregate dry seal vent or self-contained wet seal centrifugal compressor volumetric flow rate for the compressor as the sum of the volumetric flow rates determined for xv each centrifugal compressor dry seal vent or self-contained wet seal centrifugal compressor.~~

Response II-10-33: In response to comments on the December 2022 Supplemental Proposal, the EPA reconsidered establishing the performance based volumetric flow rate standard as a numeric standard.

The EPA evaluated the comments provided and have finalized the performance-based volumetric flow rate standards and presumptive standards as work practice standards (including adding repair and delay of repair provisions) and has clarified in both the preamble to the final rule and in edits to the final NSPS OOOOb and EG OOOOc regulatory text that the performance-based volumetric flow rate standards for centrifugal compressors are on a per-seal basis. Under the final NSPS OOOOb and EG OOOOc seal repair requirements, seal repair must be conducted within 90 calendar days from the date of the volumetric emissions measurement. If the repair of the wet or dry seal is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair can be delayed but must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years, whichever is earliest. In addition, if the repair requires replacement of the compressor seal or a part thereof, but the necessary replacement seals or parts cannot be acquired and installed within the repair timelines specified due to supplies being unavailable (where previously sufficiently-stocked), a delay of repair is allowed. However, in order to qualify for a delay of repair, the required seal or parts replacement must be ordered no later than 10 calendar days after the centrifugal compressor seal is added to the delay of repair list due to parts unavailability. The repair must then be completed

as soon as practicable, but no later than 30 calendar days after receipt of the replacement seal or part.

For details, please see discussion in section XI.G.2 (Numeric standard versus work practice standard), and section XI.G.3 (Clarification that the standard is based on a per-seal basis) of the final rule preamble. See also a summary of the final requirements for centrifugal compressors in section X.G of the final rule preamble.

Comment: Commenter (2258-MS) states that clarification is needed on the timing of the repair. Repair of the seal will require the compressor to be taken out of service resulting in a significant reduction in facility capacity. The commenter notes that the availability of parts is also a concern. The commenter recommends that the timing of repair be similar to fugitive emissions where parts availability and performing repairs during the next equipment outage are relevant.

Response II-10-34: As noted in response II-10-33, in response to comments on the December 2022 Supplemental Proposal, the EPA reconsidered establishing the performance based volumetric flow rate standard as a numeric standard. The EPA evaluated the comments provided and have finalized the performance-based volumetric flow rate standards as work practice standards (including adding repair and delay of repair provisions). For details, please see discussion in section XI.G.2 (Numeric standard versus work practice standard). See also a summary of the final requirements for centrifugal compressors in section X.G of the final rule preamble.

Comment: Commenters (2282-Kinder Morgan, Inc, 2305-Williams, 2399-GPA, 2428-API) request that EPA clarify in the final rule that if a defective primary dry seal or a wet seal or internal gas recovery system is repaired or replaced, or if vented emissions from a wet or dry seal compressor are routed to a process; that volumetric flow rate monitoring is not required. If vented emissions from a dry seal compressor or self-contained wet seal compressor are routed to a control device, then volumetric flow rate monitoring should be required every 26,000 hours (or three years) of operation. The commenters add that recordkeeping and reporting requirements be the same as those currently in place for other types of compressors.

Response II-10-35: For centrifugal compressors equipped with wet seals, an owner or operator that complies with the routing to a process or control device options to meet the final standards would not need to comply with the performance-based volumetric flow rate work practice standards.

Under the NSPS OOOOb, centrifugal compressor affected facilities with wet seals must comply with the GHG and VOC standards by reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent by routing emissions via a CVS to a control device. As an alternative to routing the CVS to a control device, an owner or operator may also route the CVS to a process. For specified centrifugal compressors (*i.e.*, self-contained wet seal compressor, wet seal compressor equipped with a mechanical seal, centrifugal compressors equipped with sour seal oil separator and capture system, centrifugal compressors equipped with dry seals), an owner or operator has the option to comply with the rule by meeting

the work practice performance-based volumetric flow rate standards in lieu of them being required to meet emissions be routed to a control device or process.

Thus, the EPA disagrees that there is a need to make changes to the rule for self-contained wet seal compressors that route emissions to a control device or process as those wet seal compressors are already allowed to comply with those rule requirements in lieu of the performance-based volumetric flow rate monitoring requirements under the final NSPS OOOOb standards and EG OOOOc presumptive standards.

Under the NSPS EG OOOOc, each centrifugal compressor designated facility that is a wet seal centrifugal compressor, each self-contained wet seal centrifugal compressor, and each Alaska North Slope centrifugal compressor equipped with sour seal oil separator and capture system, must comply with the GHG standards, using volumetric flow rate as a surrogate. Alternatively, owners or operators have the option of complying with the GHG standards for compressors with wet seals by reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent by meeting the requirements, or the option of routing the emissions from each centrifugal compressor wet seal fluid degassing system to a process.

For centrifugal compressors equipped with dry seals, in response to comments received on the December 2022 Supplemental Proposal, EPA has finalized a different regulatory approach for dry seal centrifugal compressor affected/designated facilities. For details, please see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble. While not required, the EPA has revised the requirements for centrifugal compressors equipped with dry seals to allow owners and operators to comply with the VOC and GHG standards for compressors with dry seals by reducing VOC and methane emissions from each centrifugal compressor dry seal system by 95.0 percent, or by comply with the option to route the emissions from each centrifugal compressor dry seal system to a process.

See also a summary of the final requirements for centrifugal compressors in section X.G of the final rule preamble.

### ***10.5.3 Recommended Monitoring Provisions (Apply to All Centrifugal Compressors)***

Comment: Commenters (2282-Kinder Morgan, Inc, 2399-GPA, 2428-API)<sup>81</sup> suggest that the EPA's detailed calibration requirements for high-volume samplers, in proposed 40 CFR 60.5386b(c)(5)(i)(B), use a more general requirement that samplers be calibrated in accordance with the manufacturer's specifications. Daily field calibration of methane concentrations and volumetric flow rate vary by manufacturer such that one set of calibration instructions is not appropriate for all high-volume samplers and should not be subject to a universal rule or standard.

Response II-10-36: EPA disagrees with the commenters and is maintaining the calibration requirements from the proposed rule. The approach we are finalizing is performance-based and designed to verify the measurement system for its application in the rulemaking. EPA also notes

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<sup>81</sup> 2428-API and 2282-KM support all 2399-GPA comments.

that if a manufacturer design is not compatible with the requirements in the final rule, the owner or operator may petition the Administrator for an alternative test method under §60.8(b).

Comment: Commenter (2282-Kinder Morgan, Inc) states that the EPA should allow the use of anemometers, calibrated bags, and other suitable methodologies approved by the EPA for measuring emission rates from dry and wet seals, consistent with Subpart W.

The commenter (2282-Kinder Morgan, Inc) states that the EPA's proposed emissions rate limit applicable to new dry seals requires flow rate measurement every 8,760 hours of operation.<sup>82</sup> To perform such flow rate measurements, the December 2022 proposed NSPS requires specific testing methods.<sup>83</sup> These testing methods require operators to incur significant costs and would not be as practical to implement as the use of anemometers, calibrated bags, and other suitable testing methods approved by the Administrator. For this reason, the commenter request that the EPA allow additional testing methods, including the use of either a hotwire or vane anemometer or calibrated bags, consistent with the measurement methodologies allowed by Subpart W.<sup>84</sup> The commenter does not suggest replacing the currently proposed measurement methods with the use of anemometers; rather, requests the use of additional compliance approaches for more flexibility, as proposed below.

The commenter (2282-Kinder Morgan, Inc) explains that the December 2022 proposed NSPS OOOOb requires that testing of volumetric flow rates using one of two methods: (1) use of a temporary or permanent flow meter according to Method 2D in Appendix A-1 of 40 C.F.R. Part 60; or (2) use of a high-volume sampler according to the methods set forth in 40 CFR 60.5386b(c).<sup>85</sup>

Beginning with the high-volume sampler method, the commenter (2282-Kinder Morgan, Inc) reports that they requested quotes from a vendor for the costs of high-volume samplers, and an individual high-volume sampler would cost \$43,100. In order to have enough high-volume samplers on hand for performing testing, the commenter would need to have approximately 32 samplers across its subsidiaries and affiliates, making the total cost to procure high-volume samplers approximately \$1,380,000. The commenter notes that this is just the capital cost for the equipment necessary to conduct testing with high-volume sampling. Additional operational costs would also result from implementing testing protocols specified in proposed 40 CFR 60.5386b(c), as well as the on-site testing. Notably, the commenter states that these costs have not been factored into the EPA's analysis of cost-effectiveness.<sup>86</sup>

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<sup>82</sup> See Proposed 40 CFR 60.5380b(a)(4)(iii). Additionally, proposed § 60.5392c(a)(1) includes the same requirements for Subpart OOOOc.

<sup>83</sup> See Proposed 40 CFR 60.5380b(a)(5)(i)(B) (providing for use of a temporary or permanent flow meter pursuant to methods in 40 CFR 60.5386b(b)), 60.5380b(a)(5)(i)(C) (providing for use of a high-volume sampler according to the method set forth in 40 CFR 60.5386b(c)). See also proposed 40 CFR 60.5392c(a)(2)(i) (same requirements, applicable in proposed EG OOOOc).

<sup>84</sup> 40 C.F.R. 98.233(o)(2)(ii), (o)(4)(ii)(B).

<sup>85</sup> See Proposed 40 CFR 60.5380b(a)(5)(i), 60.5386b(b)–(c).

<sup>86</sup> See, e.g., 87 Fed. Reg. at 74,785–86 (only considering costs of maintenance and repairs required to achieve 3 scfm emissions rate without considering testing costs).

Turning to the second method, the commenter (2282-Kinder Morgan, Inc) notes that using a temporary or permanent flow meter pursuant to Method 2D in Appendix A-1, is a less costly option than a high-volume sampler, but it is more invasive and requires physical modification to a system. Method 2D provides for measurement in a pipe or duct “through a rotameter, orifice plate, or similar device to measure flow rate or pressure drop.”<sup>87</sup> According to the commenter, this would require installing a three-way block and bleed valve on the vent system, which would cost an estimated \$2,500.00 per vent for both temporary and permanent setups. For permanent meters, the commenter reports it would cost an additional approximately \$7,400.00 for the meter to be installed permanently. These costs assume no automation.

The commenter (2282-Kinder Morgan, Inc) suggests that a flexible approach would be to also allow the use of hotwire or vane anemometers to measure flow rates, consistent with Subpart W’s approach for measuring emissions from wet seal degassing vents.<sup>88</sup> This methodology would streamline compliance activities for operators by remaining consistent with the approach under Subpart W. In the commenter’s experience, hotwire anemometers are particularly well suited to detecting small gas flows and have strong resolution at low gas flows. Additionally, to ensure accuracy, the commenter has its hotwire anemometers checked and calibrated annually by the manufacturer. Finally, they state that this approach would avoid the unnecessarily high cost of the high-volume samplers. The costs for the anemometer would involve the \$2,500 for the three-way block and bleed valve. Typically, the commenter adds that the anemometer could be used at multiple sites and would not be permanently installed.

Another approach suggested by the commenter (2282-Kinder Morgan, Inc) would be to allow the use of calibrated bags for measuring volumetric flow rates. The commenter reports that they have been successfully utilizing calibrated bags to quantify leaks on various units, including but not limited to vents and flanges, for at least the last seventeen years. This method has proven effective, reliable, and economically feasible. The commenter explains that calibrated bags are a simple concept—the volume of the bag is known, meaning the flow rate can be determined based on the amount of time needed to fill the bag. This measurement method is allowed by the EPA in Subpart W and, notably, by California’s regulations addressing methane emissions from combined seals.<sup>89</sup> Thus, in addition to anemometers, the commenter requests the EPA allow the use of calibrated bags for measuring emissions from wet and dry seals (centrifugal compressors) and rod packing (for reciprocating compressors).

In addition to these validated technologies, and recognizing that technologies continue to evolve and improve, the commenter (2282-Kinder Morgan, Inc) recommends that EPA also allow the use of any other Administrator-approved measuring method, either already approved pursuant to Subpart W, or independently approved by the Administrator pursuant to application of any final version of the Proposed NSPS Rule. They note that this is already contemplated by the EPA’s

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<sup>87</sup> 40 C.F.R. Part 60, Appendix A-1, Method 2D, § 2.0.

<sup>88</sup> Id. § 98.233(o)(2)(ii).

<sup>89</sup> See, e.g., id. §98.233(o)(2)(i)(A), (o)(4)(ii)(B), (p)(2)(ii)(A), (p)(4)(ii)(B); 17 Cal. Code Regs. §95668(c)(4)(B), (d)(4).

proposed 40 CFR 60.5405c(d), addressing “What test methods and procedures must I use for my centrifugal compressor and reciprocating compressor designated facility.”<sup>90</sup>

The commenter (2282-Kinder Morgan, Inc) states that the concept of new (undefined), alternative proposals, however, is not consistently drafted into the rule. The commenter proposes specific rule changes reflected below, and in the attached Exhibit A of their comment letter [included here], to address this concern.

Recommended *40 CFR 60.5392c(a)(2)(i)(A)* proposed changes (underlined text reflects new text and struck out text reflects deleted text):

(A) You may choose to use any of the methods set forth in §60.5405c(a) to screen for leaks/emissions. For the purposes of this paragraph, when using any of the methods in §60.5405c(a), emissions are detected whenever a leak is detected according to the method. If emissions are detected using the methods set forth in §60.5405c(a), then you must use one of the methods specified in paragraph (a)(2)(i)(B) ~~or through (F)~~ or through (F) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5405c(a), then you may assume that the volumetric ~~emissions~~ flow rate is ~~are~~ zero.

Recommended *40 CFR 60.5392c(a)(2)(i)(D) through (F)* additions (underlined text indicates new text):

(D) Use a hotwire or vane anemometer according to the methods set forth in §98.234(b).

Hotwire or vane anemometers are a common measurement method that provides reliable data, and it is more cost-effective than a flow meter or high-volume sampler. Hotwire or vane anemometers are also authorized under Subpart W, and it is a method operators are familiar with. The commenter notes that this 40 CFR 98.234(b) is a reference to the methods for use of this technology, as referenced in 40 CFR 98.233(o)(4)(ii)(B).

(E) Use a calibrated bag according to the methods set forth in §98.234(b).

40 CFR 98.234(b) notes that this is a reference to the methods for use of this technology, as referenced in 40 CFR 98.233(o)(2)(ii). The commenter states that they would be open to re-locating the same/similar methodology description into §60.5405c if that is preferred by the EPA.

(F) Use of an alternative method, as set forth in §60.5405c(d).

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<sup>90</sup> Proposed § 60.5405c(d) (“As an alternative to a high-volume sampler, you may use any other method that has been validated in accordance with the procedures specified in Method 301 in appendix A in 40 CFR part 63, subject to Administrator approval, as specified in §60.8(b).”).

Technologies continue to advance and improve. The commenter states that the EPA recognizes this in §60.5405c(d) and should explicitly state it here.

Response II-10-37: EPA disagrees with the commenter. While we acknowledge that the methods suggested by the commenter are allowed in 40 CFR part 98 subpart W and are adequate for estimating emission inventories, as noted in the December 2022 Supplemental Proposal, these types of measurements are not as well defined or prescriptive as the methods EPA generally requires for demonstrating compliance with a standard. As such, we are not updating the final rule to include these additional types of measurements.

Comment: Commenters (2366-BHE, 2428-API) recommend that for both wet and dry seal compressors, the EPA more clearly explain and define requirements for measuring seal methane emission rates. The commenters recommend that measurements include both flowrate and the methane content of the stream (measured at operators' discretion) so that scfm of methane can be determined. For wet seals with closed systems, commenter (2366-BHE) recommends that the units not require measurement or monitoring because the inherent design limits emissions. For cases where measurement is conducted, the commenter suggests that requirements be more clearly defined such that the emission threshold should be 3 scfm of methane, not a flowrate of 3 scfm.

According to commenter (2428-API), both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. The commenter recommends that the EPA make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed. The commenter specifically suggests that the EPA expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow such as:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

Response II-10-38: EPA notes that when measurement of flow rate is required, owners and operators may use a high-volume sampler. When using a high-volume sampler, the high-volume sampler must have a methane sensor. As such, the measurement is taken in terms of methane and a separate method for methane determination is not needed.

Comment: Commenter (2258-MSC) states that the EPA should allow flexibility regarding methods for identifying the need for a seal repair. The commenter notes that centrifugal compressors can be monitored for many parameters to ensure proper operation and to prevent damage to the unit. This includes monitoring and regulating gas pressure to the seals. The



commenter requests that this type of monitoring be allowed as an alternative to annual volumetric flow monitoring.

Response II-10-39: EPA notes that it has provided some flexibility in monitoring centrifugal compressor seals. For example, OGI or EPA Method 21 may be used to screen for leaks in lieu of measuring the volumetric flowrate.

#### ***10.5.4 Performance-Based Monitoring Alternative for Measurement of VOC and Methane Flow Rate***

Comment: Commenter (2317-AOGA) requests that EPA add a performance-based monitoring alternative for measurement of VOC and methane flow rate from seal gas vents. The commenter explains that wet seal compressors deployed in the natural gas transportation sector process pipeline quality natural gas which is 95.0 to 98.0 percent methane.<sup>91</sup> Compressors installed in upstream oil and gas production operations process gas that includes other constituents, such as carbon dioxide and ethane, and that exhibits sharp variations in flow volume over short intervals. A volumetric flow limit for VOCs and methane from seal gas vents in oil and gas production must be supported by a monitoring method that is capable of screening out other constituents in the vent gas stream. The two methods proposed in EG OOOOc to monitor the seal gas vent flow rate, Method 2D and a high-flow sampler,<sup>92</sup> lack that capability [same two methods included in NSPS OOOOb].

Commenter (2317-AOGA) notes that Method 2D – Measurement of Gas Volume Flow Rates in Small Pipes and Ducts, requires that all the gas flow in the pipe or duct is directed through a rotameter, orifice plate or similar device to measure volume flow rate or pressure drop. The method also requires that the device has been previously calibrated in a manner that ensures its proper calibration for the gas being measured. Absolute temperature and pressure measurements are made to allow correction of volumetric flow rates to standard conditions. The method also provides general specifications for the gas meter. “A rotameter, orifice plate, or other volume rate or pressure drop measuring device capable of measuring the stack flow rate to within  $\pm 5$  percent. The metering device shall be equipped with a temperature gauge accurate to within  $\pm 2$  percent of the minimum absolute stack temperature and a pressure gauge (accurate to within  $\pm 5$  mm Hg). The capacity of the metering device shall be sufficient for the expected maximum and minimum flow rates at the stack gas conditions.”

Commenter (2317-AOGA) notes that gas flow rates from centrifugal compressor vents may be very low and non-continuous. Volumetric flow meter technologies prescribed by Method 2D may not be able to accurately measure these low volume flow rates. Other technologies, e.g., thermal mass flow meters (TMFMs), are capable of accurately measuring very low gas flow rates. TMFMs measure mass flow, which can easily be converted to volume flow based on engineering knowledge of the gas being measured. In fact, the EPA has evaluated TMFMs and determined that the technology can measure flow as accurately or more accurately than volume

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<sup>91</sup> <https://www.epa.gov/natural-gas-star-program/overview-oil-and-natural-gas-industry>.

<sup>92</sup> Proposed § 60.5405c(b). 28 Proposed § 60.5405c.

flow meters. TMFMs can meet or exceed the  $\pm 5$  percent accuracy requirements in Method 2D, but they do not meet the requirement in that method to measure volume flow rate.

Commenter (2317-AOGA) recommends that the proposal be revised to set performance-based flow measurement criteria, as an alternative to Method 2D. Any commercially available technology that is suitable and capable of accurately measuring gas flow to within  $\pm 5$  percent should be authorized to monitor compliance with the volumetric flow limit for centrifugal compressor seal gas vent flow. Thermal mass flow meters should be authorized, even though they do not directly measure volumetric flow rate. They added that other current or future commercially available technologies should also be allowed, if they meet minimum performance specifications. Importantly, the accuracy specifications should accommodate variability resulting from low flow conditions.

Commenter (2317-AOGA) states that the proposal allows parties to apply to the EPA for validation of alternate test methods following the procedures of Method 301, subject to Administrator approval as specified in 40 CFR 60.8(b). However, the commenters contend that this option is unnecessarily burdensome and time-consuming, where a performance-based set of measurement criteria can ensure accuracy while providing flexibility to adapt measurement techniques to the challenges of low flow volumes, variability in the composition, density and molecular weight of vent gas and variability in the flow rate. The commenter requests that the rules allow flow rate measurement (volume or mass) approaches using any instrument appropriate for the vent stream being measured, properly calibrated and meeting  $\pm 5$  percent accuracy requirements. With these refinements, the commenter would support a volumetric de minimis limit as a vehicle to establish BSER for wet seal compressors deployed in Alaska production operations.

This commenter (3839-AOGA) also provided additional information on their concerns related to being able to account for non-methane and non-VOC gas accounting when conducting volumetric flow rate monitoring methods. They reiterated that the two methods proposed by EPA to monitor the seal gas vent flow rate, Method 2D and a high-flow sampler, lack that capability.” The commenter notes that upstream field gas compressed by centrifugal wet seal compressor (and dry seal compressors) likely has significant volumes of non-methane/non-VOC constituents in the gas (ethane, carbon dioxide, etc.). The state that these constituents should be able to be subtracted from the volumetric measurement using engineering knowledge and calculations. Then the resulting flow measurement can be compared against the propose volumetric standard. They add that TMFMs should be allowable to derive a volumetric flow in low pressure/low flow situations like those on the ANS for wet seal compressor vents. They contend that they are also more precise than the technologies described in Method 2D for low pressure/low flow circumstances. As written, they state that the precision requirements ( $\pm 5\%$ ) of Method 2D will likely not be able to be achieved for these low pressure/low flow situations, which necessitates a compliance option that is feasible. The commenter believes that would be the allowance of a TMFM, but a different proposal would be to change the precision requirements for these applications to allow a wider range of precision that what is in Method 2D. AOGA suggests an allowance of up to  $\pm 10\%$  for low pressure/low flow situations.

Response II-10-40: Mass thermal flowmeters rely on knowledge of the gas stream in order to provide accurate measurements. EPA is concerned that due to the variability in the gas that may leak from the compressor a mass thermal flowmeter may not be able to provide accurate measurements. Without further information to demonstrate that the variability of the gas stream is unimportant to the precision of the measurement, EPA considers the more direct measurement techniques of EPA Method 2D to be more appropriate for measuring the volumetric flowrate from the compressor.

EPA Method 2D describes how to conduct the measurement of flow through direct measurement or by using pressure drop measurements to calculate flow. The method allows for many different types of measurement devices, including but not limited to rotameters and orifice plates, to accomplish the measurement, as long as the device measures the gas flow (volume rate or pressure drop) accurately. Because EPA Method 2D is not limiting in the types of measurement devices that can be used, we believe the method provide owners and operators with enough flexibility to choose the type of measurement device that works best for the situation.

EPA notes that when measurement of flow rate is required, owners and operators may use a high-volume sampler. When using a high-volume sampler, the high-volume sampler must have a methane sensor. As such, the measurement is taken in terms of methane and a separate method for methane determination is not needed.

## Chapter 11. Reciprocating Compressors

### 11.1 New Source Performance Standard (NSPS) OOOOb Affected Facility/Definitions

[**Note:** Many of the comments provided for reciprocating compressors would also apply to designated facilities under EG OOOOc. For comments that were provided with the specific focus on EG OOOOc, see section 11.4 of this Chapter.]

Comment: Commenter (2227-Western Energy Alliance (WEA)) states that the EPA should not be regulating reciprocating compressors that are non-emitting. The commenter notes that rod packings routed to a closed vent system (CVS) provide a solution for eliminating emissions, yet EPA is treating them as affected facilities with unnecessary regulation. If any leaks were to occur in the CVS, the emissions would be detected and repaired through leak detection and repair (LDAR) inspection requirements.

Response II-11-1: The final NSPS OOOOb standards and EG OOOOc presumptive standards both allow for owners and operators, as an alternative to meeting a performance-based volumetric flow rate standard, to collect emissions (methane and/or VOC) from their reciprocating compressor rod packing using a rod packing emissions collection system that is operated to route the rod packing emissions to a process through a closed vent system. In order to comply with this option, the owner or operator must equip the reciprocating compressor with a closed vent system that meets design requirements and operates with no identifiable emissions, which consists of using procedures for conducting OGI as specified under the CVS requirements. The EPA disagrees that these affected facility/designated facility requirements constitute unnecessary regulation as there is a need to ensure the integrity of the CVS, and EPA has included the minimum requirements necessary to ensure compliance.

See section X.I. of the final rule preamble for a summary of the final standards/presumptive standards for reciprocating compressors. See final standards/presumptive standards at 40 CFR 60.5385b and 40 CFR 60.5393c.

Comment: Commenters (2257-Michigan Oil and Gas Association (MOGA), 2326-American Exploration and Production Council (AXPC)) support the EPA's exemption of reciprocal compressors "located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility" as provided in both new source performance standards (NSPS) OOOO and NSPS OOOOa. According to commenter (2257-MOGA), well operators visit and service these wells and associated compressors daily to inspect for proper operation, leaks and to conduct maintenance and repair activities. Any necessary repairs are repaired as soon as possible to avoid product loss and to maximize profit returns. Further, the commenter suggests that if the EPA wishes to propose monitoring for well site compressors, the commenter recommends the EPA allow the more feasible and cost-effective monthly Auditory, Visual & Olfactory (AVO) inspection and documentation, similar to the requirements allowed under 40 CFR 60.5416a.

Response II-11-2: Section XI.I.5 of the preamble to the final rule details EPA's rationale and reasoning regarding the applicability of requirements to compressors located at centralized

production facilities. Reciprocating compressors located at well sites are not subject to requirements. However, reciprocating compressors located at centralized production facilities that consist of equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells (including reciprocating compressors) are subject to reciprocating compressor requirements.

Comment: Commenters (2305-Williams, 2428-American Petroleum Institute (API)) state that the rule does not address conducting annual measurements on temporary, portable and emergency compressors. The commenters contend that these compressors should be exempt from 40 CFR 60.5365b(c) because, according to commenter (2428-API) conducting these measurements is logistically impractical and that equipment that is intended for temporary use and is not a stationary source should not be subject to either NSPS OOOOb or emission guidelines (EG) OOOOc.

According to commenter (2305-Williams), these compressors are on-site typically less than 12 calendar months and/or operate for 10-20% of normal annual operating schedule. They add that many states provide for this operating flexibility within existing permits or the current structure of air regulations.

Commenter (2428-API) requests the EPA make the following clarifications to address this concern (underlined text reflects new text):

*40 CFR 60.5365b(c):*

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.

Response II-11-3: With regards to the commenters' request that the applicability of the rule not apply to temporary, portable and emergency compressors because conducting measurements is logistically impractical, the EPA disagrees. The EPA considered similar comments on the November 2021 Proposal, see discussion in section IV.I.1.b of the December Supplemental Proposal preamble,<sup>1</sup> and maintains that basing reciprocating compressor flow rate monitoring on the hours of operation (*i.e.*, 8,760 hours) in lieu of requiring monitoring based on a calendar year addresses limited-use reciprocating compressors and allows owners and operators flexibility when planning maintenance and an exemption is not warranted.

Comment: Commenter (2172-Kentucky Oil and Gas Association (KOGA)) suggests that the EPA's proposal to define an additional group of well affected facilities (*i.e.*, the "small well

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<sup>1</sup> 87 FR 74796, December 6, 2022.

site”) and allowing a single well with a single piece of production equipment (such as a small compressor) to perform fugitive emission surveys as in what is required for a single well, should also be extended to cover reciprocating compressors.

Response II-11-4: Section XI.I.5 of the preamble to the final rule details EPA’s intent regarding the applicability of requirements to compressors located at centralized production facilities. That intent is that reciprocating compressors located at well sites are not subject to reciprocating compressor requirements. This is included in the final rule. However, reciprocating compressors located at centralized production facilities that consist of equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells (including reciprocating compressors) are subject to reciprocating compressor requirements.

## **11.2 NSPS OOOOb Proposed Best System of Emission Reduction (BSER)**

[*Note:* Most of the comments provided on the BSER for NSPS OOOOb also apply to EG OOOOc. For specific comments that apply to EG OOOOc, see section 11.4 of this Chapter).]

### ***11.2.1 Work Practice Standard vs Emission Limitation Standard***

Comment: Several Commenters (2305-Williams, 2326-AXPC, 2399-GPA Midstream Association (GPA), 2428-API, 2483-Interstate Natural Gas Association of America (INGAA)) state that reciprocating compressor rod packing requirements should be considered a work practice standard instead of an emission standard. The commenters state that under a work practice standard, the operator would screen the compressor to determine the volumetric leak rate from each cylinder and replace the rod packing where the volumetric leak rate exceeds the applicable threshold. So long as the operator timely replaces rod packing, there is no deviation. Therefore, the volumetric flow rate would serve as a trigger for repair activity under a work practice standard instead of a numeric emission standard.

Commenter (2483-INGAA) states that in the November 2021 proposal, the EPA described a work practice standard that would require yearly monitoring and replacement of the rod packing when the measured emissions exceed 2 standard cubic feet per minute (scfm). The EPA cited the Natural Gas STAR document in the November 2021 proposal that described a work practice approach for rod packing replacement. The commenter further states that the work practice approach, including a 2 scfm threshold for triggering rod packing replacement, was further demonstrated at the EPA’s November 2019 Natural Gas STAR and Methane Challenge Workshop.<sup>2</sup> The commenter adds that the California regulation<sup>3</sup> cited by the EPA in the Technical Support Document (TSD) is also a work practice standard with a 2 scfm threshold. However, the commenter notes that the EPA appears to have proposed an emission limitation standard in the December 2022 proposal. The 2022 Supplemental Background TSD does not

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<sup>2</sup> “DTE Energy Rod Packing Evaluation and Replacement Program,” U.S. EPA 2019 Natural Gas STAR & Methane Challenge Workshop (November 2019).

<sup>3</sup> CARB. “[Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.]” Oil and Gas Final Regulation Order (ca.gov).

include any information to support an emission standard rather than a work practice – and the October 2021 original Background Technical Support Document<sup>4</sup> envisioned a work practice. Thus, if EPA intended to propose an emission limitation standard, it gave no justification for, or analysis of, the change, which the commenter states is arbitrary and capricious. The commenter continues that based on the two TSDs; it appears that EPA intended to propose a work practice standard that triggers rod packing maintenance when the threshold is exceeded. The extensive and case-by-case nature of rod packing replacement makes it particularly unsuitable for an emission limitation standard.

Commenter (2399-GPA, 2428-API)<sup>5</sup> states that similar to the LDAR program, owners and operators would have to monitor the rod packing to determine if fugitive emissions have reached a threshold level and, if the threshold is reached, repair or replace the rod packing. Such a situation accords with the statute’s determination of when using a work practice standard is appropriate: where “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” 42 U.S.C. § 7411(h)(2).

Commenters (2305-Williams, 2399-GPA, 2428-API)<sup>6</sup> state that as an emission standard, the proposed rod packing requirements are unworkable. Operators would be forced to decide between continuing to operate out of compliance until a maintenance shutdown can be scheduled or shutting down the compressor immediately to conduct the repair and venting or flaring gas that can no longer be compressed and transported during the unscheduled shutdown. A forced shutdown will likely result in significantly more emissions than continuing to operate until the next scheduled maintenance shutdown. For systems that are at capacity, shifting the incoming gas to another station is not a feasible or reliable option, resulting in additional flaring and venting, which is magnified given the time it takes to have producers shut-in wells. According to commenter (2305-Williams), the December 2022 proposal also makes an incorrect assumption that the gas can simply be rerouted to other natural gas compression facilities, but often that is not a possibility as piping is not in place to bypass a facility, or there may not be an alternative facility available. Commenter (2428-API) adds that while it is true that flow can be measured, it is not technically or economically practicable to install measurement systems that would assure compliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

Commenters (2305-Williams, 2399-GPA) suggest that under a work practice framework (which they say is the only supported option), companies would be required to complete a corrective action within 720 hours of operation (equivalent to 30 days) and allow for delay of repair, similar to leak monitoring programs, of up to two years if repair goes beyond the replacement of rod packing. The commenters note that exceeding the vent rate threshold after the time for corrective action would be a deviation, but exceeding the vent rate within the time allotted to correct would not.

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<sup>4</sup> EPA, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) (Oct. 2021), Docket ID No. EPA-HQ-OAR-2021-0317-0166 (hereinafter “2021 Background TSD”).

<sup>5</sup> API endorses GPA’s comments.

<sup>6</sup> API endorses GPA’s comments.

Response II-11-5: Section XI.I.1 (Numeric standard versus work practice standard) of the preamble to the final rule details EPA's rationale and reasoning that responds to the numeric standard versus work practice standard comments and establishes final standards/presumptive standards related to reciprocating compressors as work practice standards.

Comment: Commenter (2428-API) states the EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, the commenter suggests that the EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. According to the commenter, the EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. The commenter states that the EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, the commenter (2428-API) argues that, if the EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that the EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If the EPA takes this path, a re-proposal is necessary so that commenters can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record.

Response II-11-6: Section X.I.1 (Numeric standard versus work practice standard) of the preamble to the final rule details EPA's rationale and reasoning that responds to the numeric standard versus work practice standard comments and establishes final standards/presumptive standards related to reciprocating compressors as work practice standards.

### ***11.2.2 Clarification that Emissions Threshold is on a Per Cylinder Basis***

Comment: Several commenters (2258-Marcellus Shale Coalition (MSC), 2282-Kinder Morgan, Inc., 2305-Williams, 2326-AXPC, 2366-Berkshire Hathaway Energy Company (BHE), 2391-Chesapeake Energy Corporation (CEC), 2399-GPA, 2428-API, 2483-INGAA) request clarification that the volumetric standard applies to each rod packing (or throw) or set of packing and not the entire compressor and that the rule text clearly addresses manifolded vents on a combined basis. The commenters cite the precedent set by the California Air Resources Board (CARB) where reciprocating compressors in California are restricted to 2 scfm per rod packing, and not per compressor as set forth in 17 CCR § 95668(c)(4)(D), Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities) (allowing for "a combined rod packing or seal emission flow rate greater than the number of compression cylinders multiplied by two (2) scfm") which states:

(6) with a rod packing or seal with a measured emission flow rate greater than two (2) standard cubic feet per minute (scfm), or a combined rod packing or seal emission flow



rate greater than the number of compression cylinders multiplied by two (2) scfm...

The commenters (2258-MSA, 2282-Kinder Morgan, Inc., 2305-Williams, 2326-AXPC, 2366-BHE, 2391-CEC, 2399-GPA, 2428-API, 2483-INGAA) state that this approach makes sense and is consistent with the proposed BSER from the November 2021 proposal. In addition, the EPA based its proposal to measure the flow rate of each cylinder on volumetric emission factors used in the 1996 EPA/GRI report quantifying methane emissions from the U.S. natural gas industry—which EPA notes are per cylinder. See 86 Fed. Reg. at 63216 & n.277.

Commenter (2399-GPA, 2428-API)<sup>7</sup> states that combining is appropriate because a single reciprocating compressor may have multiple cylinders (also referred to as compression cylinders, throws, or packing case vents) routed to a common vent stack, making rod packing-specific measurements impractical and unreasonable.

According to commenter (2282-Kinder Morgan, Inc.), the EPA’s preamble discussion, and at least some of the proposed rule text, imply that the emissions rate would be on a per-rod packing basis, and the commenter understands this to be the EPA’s intent. It is important that the EPA’s final rule more clearly reflect this intent. Specifically, according to commenter (2428-API), the proposed text provided in 40 CFR 60.5380b or 40 CFR 60.5385b(a), does not provide the distinction that the limits are per cylinder. It would be impractical for a compressor with multiple cylinders to operate the same as a compressor with only a single cylinder.

Commenter (2282-Kinder Morgan, Inc.) states that the rule language must more clearly address manifolded vents (of multiple rod packing units) on a combined basis. The commenter supports the approach to determine the required leak rate for the manifolded units, whereby the operator would multiply the required flow rate by the number of units flowing to that single vent. It appears that this concept of multiple seals manifolded to one vent is intended to be captured in the proposed regulations at 40 CFR 60.5380b(a)(5)(i)–(ii), 60.5415b(d)(2), 60.5392c(a)(2)(i)–(ii), and 60.5415c(c)(1). However, the proposed regulatory sections addressing the actual volumetric flow rate requirement do not clearly incorporate the preamble concept of multiplying the emissions rate by the number of manifolded cylinders or throws. The commenter asserts that this lack of regulatory text on manifolded vents makes it difficult for operators to rely on the preamble text alone.

Several commenters (2282-Kinder Morgan, Inc., 2305-Williams, 2391-CEC, 2399-GPA, 2428-API, 2483-INGAA) provide suggested changes to regulation language to address concerns. The commenters urge the EPA to adopt their proposed revisions. They explain that their suggested changes will clarify the regulatory text to align with the intent of the December 2022 proposal preamble to allow for grouping of manifolded vents where an emissions rate limit is applicable to such rod packing or throw.

- Commenter (2305-Williams) recommends that 40 CFR 60.5385b(a) be revised as follows (underlined text reflects new text):

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<sup>7</sup> GPA comments endorsed by API.

*40 CFR 60.5385b-*

(a) The volumetric flow rate, measured in accordance with paragraphs (b) or (c) of this section, must not exceed 2 standard cubic feet per minute (scfm) per cylinder or a combined rod packing emission flow rate greater than the number of compression cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

- Commenter (2391-CEC) suggests adding “of each compressor cylinder” or similar language as appropriate in proposed 40 CFR 60.5385b and 60.5393c. They also request that EPA also make conforming edits to other provisions in both NSPS OOOOb and EG OOOOc, as necessary. Example language follows:

§60.5385b What GHG and VOC standards apply to reciprocating compressor affected facilities?

Each reciprocating compressor affected facility must comply with the GHG and VOC standards, using volumetric flow rate of each compressor cylinder as a surrogate, in paragraphs (a) through (c) of this section, or the GHG and VOC standards in paragraph (d) of this section. You must also comply with the requirements in paragraphs (e) through (g) of this section.

(a) The volumetric flow rate of each compressor cylinder, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm). You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.\*\*\*

- Commenter (2399-GPA) suggests the following edits to 40 CFR 60.5385b(a) (underlined text reflects new text):

*40 CFR 60.5385b(a)-*

The volumetric flow rate, measured in accordance with paragraphs (b) or (c) of this section, must not exceed 2 standard cubic feet per minute (scfm) per cylinder, or a combined rod packing emission flow rate greater than the number of compression cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

- Commenter (2483-INGAA) suggests the following edits to 40 CFR 60.5385b(a) and 60.5393c(a) (underlined text reflects new text and struck out text reflects deleted text):

*40 CFR 60.5385b(a)/40 CFR 60.5393c-*

~~(a) The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm). You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section and determine the volumetric flow rate in accordance with paragraph (b) of this section. If the volumetric flow rate, measured in accordance with paragraph (b) of this section, for a rod packing exceeds 2 standard cubic feet per minute (scfm), or if the combined volumetric flow rate, measured in accordance with paragraph (b) of this section, for multiple rod packings that are manifolded together exceeds 2 scfm multiplied by the number of rod packings, the rod packing or packings must be repaired as provided in paragraph (a)(3) of this section.~~

- Commenter (2428-API) suggests the following edits to 40 CFR 60.5385b(a) and 60.5393c(a) (underlined text reflects new text):

*40 CFR 60.5385b(a)/40 CFR 60.5393c(a)-*

(a) The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

- Commenter (2282-Kinder Morgan, Inc.) requests that the EPA incorporate modest changes to 40 CFR 60.5393c(a), 60.5410c(d)(1), and 60.5415c(f)(1), as well as the respective NSPS OOOOb provisions.<sup>8</sup> The commenter notes that their proposed changes would align the regulatory language with the intent that the required flow rate for more than one rod packing unit that are manifolded to one vent would be the rate limit for an individual rod packing unit, multiplied by the number of units and to clarify the standards' applicability to individual rod packing units rather than an entire compressor. Recommended changes are provided below (underlined text reflects new text and struck out text reflects deleted text). [This comment applies to both NSPS OOOOb and EG OOOOc, although change recommendations were only provided for EG OOOOc regulation.]

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<sup>8</sup> The commensurate sections in Subpart OOOOb would be §§60.5385b(a), and 60.5410b(e)(1).

*40 CFR 60.5393c(a)-*

(a) The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm), or in the case of manifolded groups of reciprocating compressor rod packing vents, 2 scfm multiplied by the number of individual reciprocating compressor rod packing units. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.

*40 CFR 60.5393c(a)(1) suggested changes (underlined text reflects new text)-<sup>9</sup>*

(1) You must conduct your first volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after the effective date of an approved state or tribal plan or on or before 8,760 hours of operation after startup, whichever is later.

The commenter (2282-Kinder Morgan, Inc.) proposes to use “applicable” here given their suggested revisions above which clarify that if there is more than one rod packing unit, the target threshold is 2 scfm multiplied by the number of units.

*40 CFR 60.5393c(a)(2) suggested changes (underlined text reflects new text and struck out text reflects deleted text) -<sup>10</sup>*

(2) You must conduct subsequent volumetric flow rate measurements from your reciprocating compressor rod packing vent on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 2-scfm-applicable volumetric flow rate.

*40 CFR 60.5410c(d)(1) suggested language (underlined text reflects new text and struck out text reflects deleted text) -*

(1) If you comply with §60.5393c(a) by maintaining volumetric flow rate ~~below 2 scfm~~, you must maintain the volumetric flow rate for each rod packing unit below 2 scfm (or in the case of manifolded groups of reciprocating compressor rod packing vents, 2 scfm multiplied by the number of individual reciprocating compressor rod packing units), and you must conduct your initial annual volumetric flow rate measurement as required by §60.5393c(a)(1).

*40 CFR 60.5415c(f)(1) suggested language (underlined text reflects new text and struck out text reflects deleted text) -*

(1) You must maintain the volumetric flow rate at or below 2 scfm (or in the case of manifolded groups of reciprocating compressor rod packing vents, 2 scfm multiplied

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<sup>9</sup> The Subpart OOOOb section to which these changes should also apply is 40 CFR 60.5410b(e)(1).

<sup>10</sup> The Subpart OOOOb section to which these changes should also apply is 40 CFR 60.5410b(e)(2).

by the number of individual reciprocating compressor rod packing units) and you must conduct the required volumetric flow rate measurement of your reciprocating compressor rod packing in accordance with §60.5393c(b) on or before 8,760 hours of operation after your last volumetric flow rate measurement which demonstrated compliance with the ~~2-scfm~~applicable volumetric flow rate.

Response II-11-7: Section XI.I.3 (Clarification that the standard is based on a per-cylinder basis) of the preamble to the final rule responds to these comments. The EPA agrees that the basis and intent of the performance-based volumetric flow rate standard is that it be applied on a per-cylinder basis and that clarity was needed in both the NSPS OOOOb and EG OOOOc regulatory text. EPA considered the comments/suggested edits and made the necessary clarifying changes to the final NSPS OOOOb and EG OOOOc regulatory text to address commenter's concerns.

### ***11.2.3 Other Comments on Proposed Standards***

Comment: Several commenters (2282-Kinder Morgan, Inc., 2410-California Office of the Attorney General (CA AG) et al, 2433-Environmental Defense Fund (EDF) et al, 2483-INGAA) express general support for the EPA's proposed standard for all reciprocating compressors, except those located at well sites.

However, while commenter (2433-EDF et al) expresses support for key aspects of the EPA's proposed standards for reciprocating compressors, including extending requirements to existing sources and to centralized production facilities in the production segment, the commenter urges the EPA to lower the emissions threshold for rod packing replacement based on annual monitoring and to consider measures to reduce the significant emissions from compressor exhaust.

Response II-11-8: For comments that are supportive comments on reciprocating compressor requirements as of the December 2022 Proposal, the proposed requirements have not changed and no response is required.

In response to the comment urging EPA to lower the emissions threshold for rod packing replacement, there is insufficient information at this time to support the establishment of a standard based on a lower volumetric flow rate.

In response to the commenter's request that EPA consider measures to reduce emissions from compressor exhaust, see Response II-11-20.

Comment: Commenter (2180-Pennsylvania Department of Environmental Protection (PADEP)) disagrees with the proposed rule requirements for reciprocating compressors. Since 2018, the commenter reports that the State of Pennsylvania has required similar reciprocating compressors to replace the rod end packing after every 26,000 hours of operation or every 36 months. The commenter also disagrees with the EPA's proposal mandating that oil and gas operators must monitor and quantify emissions from the rod end packing and replace the packing if the volumetric flow rate exceeds 2 standard cubic feet per minute (scfm). The commenter recognizes that the proposed emission limit of 2 scfm is equivalent to a flow rate of 120 standard cubic feet

per hour (scfh), which is approximately double the maximum emission rate of reciprocating compressors found in Table 7-2 of the technical support document (TSD) (EPA-HQ-OAR-2021-0317-0166). The commenter suggests that the EPA either reconsider the 2 scfm emission rate and reduce the emission rate to 1 scfm or less to be consistent with the emission rates in Table 7-2; or, maintain the 26,000 operating hour or 36-month replacement schedule.

Response II-11-9: In response to the comment requesting that EPA lower the emissions threshold for rod packing replacement, there is insufficient information at this time to support the establishment of a standard based on a lower volumetric flow rate.

With regards to the comment noting that the 2 scfm performance-based volumetric flow rate standard is more than double the maximum emission rate of reciprocating compressors found in Table 7-2 of the November 2021 TSD, and that the emission rates in Table 7-2 support requiring a lower performance-based volumetric flow rate standard for reciprocating compressors, we disagree. The baseline estimates in Table 7-2 represent an average and individual reciprocating compressor volumetric flow rates would be expected to be both higher and lower than the rates included in Table 7-2. As noted in the November 2021 TSD, the emissions after the replacement of the rod packing were calculated using an emission rate of 11.5 scfh/cylinder, which is the emission factor identified by EPA's Natural Gas Star program as representing emissions from newly installed rod packing.<sup>11</sup> Emissions would be expected to increase (and emission reductions decrease) in subsequent years until the next time the annual measurements require that the rod packing be replaced. As for the request that the EPA maintain the 26,000 operating hour or 36-month replacement schedule, see section XI.I.2 (Rod packing changeout schedule-based approach) of the preamble to the final rule for EPA's response to that comment.

Comment: Commenter (2248-North Dakota Petroleum Council (NDPC)) states that they believe the requirements [for reciprocating compressors] are onerous and costly. The commenter contends that any benefits that could potentially come from requiring replacement will be outweighed by these significant costs.

Response II-11-10: The EPA maintains, as it did in sections XII.E.1.d and 2 of the November 2021 Proposal preamble, that BSER under the NSPS OOOOb standards and EG OOOOc presumptive standards is annual rod pack flow rate monitoring and replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm for all segments. The commenter's inference is that the requirement to repair or replace rod packing to maintain the performance-based volumetric standard will require that owners or operators will need to replace the rod packing more frequently than under the NSPS OOOOa fixed-schedule requirement to replace rod packing. The EPA contends that, based on the performance-based flow rate monitoring standard, while there will be some reciprocating compressors that will be required to change out rod packing more frequently, there will also be some reciprocating compressors that will be required to change out rod packing less frequently.

Comment: Several commenters (2258-MS, 2305-Williams, 2399-GPA, 2428-API) request that they have the option to use proven add-on controls, such as an existing combustor or flare, be

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<sup>11</sup> 2011 TSD, pg. 6-13.

allowed in addition to routing to a process. The commenter explain that such options may be key for existing units and units that are modified or reconstructed.

Commenters (2305-Williams, 2399-GPA, 2428-API)<sup>12</sup> provide several reasons for why it may not always be feasible to route rod packing vents back to the process:

- Depending on the pressure differential between nearly ambient rod packing vents and pressurized piping, substantial horsepower may be required to achieve capture.
- Recompression designs require substantial horsepower and could require gas engines of variable horsepower to achieve the recompression, negating some of the emissions reductions this rule seeks to achieve.
- Currently available rod packing capture systems attempted by Williams and others in the industry have performed poorly or are ineffective in certain applications or configurations.
- Rod packing vents are essentially at ambient pressure, creating a situation where oxygen could be introduced into the process gas leading to safety concerns.
- The gas quality in the rod packing vents may not be compatible with the only technically feasible location in the process, based on pressure differentials, for the gas to be routed. For example, if the gas in the compressor is sour gas, but the only technically feasible place for the gas to be absorbed in the process is the fuel gas system, the sour gas is often not a good candidate for fuel gas use due to the detrimental effect on components.

According to commenter (2399-GPA), currently available rod packing capture systems that have been attempted by the commenter and their members have not performed as intended and, in some applications, have not worked at all. They explain that even if these systems were as effective as advertised, timing is a significant concern as the supply is not currently available to meet demand. The commenter recommends that where rod packing vents are routed to a control device, they recommend that the flow be measured every 26,000 hours of operation. The commenter provides that this would ensure that rod packing is appropriately maintained while overall emissions are greatly reduced.

Commenter (2428-API) suggests that the emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95 percent destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This, according to the commenter, is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

Response II-11-11: Section X.I.4 (Routing to process or control device) of the preamble to the final rule responds to these comments. The EPA has revised the final reciprocating compressor requirements under NSPS OOOOb and EG OOOOc to allow owners or operators of

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<sup>12</sup> Comments provided by GPA are endorsed by API.

reciprocating compressors the option of routing emissions to a control device that achieves 95 percent control to meet the final rule standards and presumptive standards.

Comment: Several commenters (2227-WEA, 2258-MSO, 2282-Kinder Morgan, Inc., 2298-Pioneer Natural Resources USA, Inc. (Pioneer), 2326-AXPC, 2366-BHE, 2399-GPA, 2428-API, 2483-INGAA) note that given the uncertainties of the assumptions underlying the BSER evaluations for the two options, and that the cost effectiveness of the two options are very close, they urge the EPA to provide flexibility to affected facilities by adopting both standards as BSER alternatives with the operator selecting their preferred approach.

According to commenter (2366-BHE), retaining the schedule-based approach is warranted because that compliance option has not only been implemented at NSPS OOOOa facilities, but also through state regulations and voluntary actions by companies. The prescribed maintenance schedule is also an EPA-approved best management practice for the voluntary Methane Challenge program. Due to these EPA decisions, the commenter reports that many companies have “built out” reciprocating compressors rod packing maintenance programs using schedule maintenance, including existing compressors not subject to the federal mandate or state rules. According to the commenter, it is critical that these existing and successful company programs not be supplanted by different requirements in NSPS OOOOb and EG OOOOc.

Several commenters note specific suggestions with respect to a fixed schedule:

- Several commenters (2258-MSO, 2298-Pioneer, 2326-AXPC) request that the EPA allow rod packing replacement every 8,760 operating hours.
- Commenter (2428-API) requests that the EPA allow replacement annually or 8,760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and NSPS OOOOa.
- Commenter (2366-BHE) requests retaining the NSPS OOOOa approach, requiring the replacement of rod packing every 3 years or 26,000 hours of operation (if operating hours are monitored).

Several commenters (2227-WEA, 2298-Pioneer, 2326-AXPC, 2399-GPA, 2428-API) request that the EPA specify that where operators choose to replace rod packing on a fixed schedule, that they not be required to measure volumetric flow rates.

Response II-11-12: Section X.I.2 (Rod packing changeout schedule-based approach) of the preamble to the final rule responds to these comments.

Comment: Commenter (2366-BHE) requests that EPA provide data to support the 2 scfm emission rate threshold for higher pressure scenarios. They note, for example, that compressors at natural gas storage facilities may warrant a higher threshold for operations with significantly higher operating pressures.

Response II-11-13: Available information does not include flow rate/emissions data by operating pressures and the commenter did not provide any information to support their claim or to establish a different standard.



Comment: Commenter (2172-KOGA) states that the proposal for operators to monitor rod packing emissions to determine when the rod packing needs to be repaired or replaced is appropriate for large compressors or compressor stations. However, the commenter states that this type of monitoring of the typical small compressors used in the Appalachian Basin to deliver gas to intermediate gathering systems from fields of low volume/low pressure wells for sale, is problematic. The commenter explains that most small reciprocating compressors, compressors that may have pistons as small as 2", may not be equipped with crank case ports from which to measure blowby. There is a concern as to what would happen to the lubricant in the crankcase when pressure is added to be able to measure the packing emission volume.

The commenter (2172-KOGA) adds that the EPA's previously proposed requirement of replacing rod packing on a schedule is still a viable option to measuring packing blow by for a small operator. However, the commenter believes that the 36-month requirement for the typical small compressor of the Appalachian Basin is too short of a time frame. The commenter states that rod packing compressors that run at a low RPM and pressure can typically exceed 36 months.

Commenter (2172-KOGA) recommends that the EPA adopt a two-tiered approach to emissions control from reciprocating compressors. Production facilities with more than one compressor would be required to have rod packing repaired or replaced in the case of measurable blowby of 2 cubic feet per hour. For production facilities with a single compressor, rod packing repairs or replacement is not to exceed every 48 months or 35,040 hours of run time. This two-tiered approach differentiates requirements because small operators rarely operate facilities with more than one compressor at a time. Production facilities with more than one compressor are more typical of large-company and transmission pipeline operations who would be more apt to have the technical ability to measure crankcase blow by.

Response II-11-14: Section X.I.1 (Numeric standard versus work practice standard) of the preamble to the final rule details EPA's rationale and reasoning that responds to the numeric standard versus work practice standard comments and establishes final standards/presumptive standards related to reciprocating compressors as work practice standards, including repair and delay of repair requirements. These requirements apply to both large and small operators. Where an owner or operator is complying with the performance-based volumetric flow rate standard, if the measured volumetric flow rate 2 scfm or below, an owner or operator would not be required to change out the rod packing, which could be the case for a small reciprocating compressor, even after 26,000 hours of operation.

In response to comment that small compressors may not be equipped with crank case ports from which to measure blowby, the final rule allows owners or operators to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, they would be allowed to conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

The final requirements for reciprocating compressors under NSPS OOOOb and EG OOOOc also include several alternative compliance options to the performance-based volumetric flow rate

standard that an owner or operator can comply with to meet the standards. See section X.I. of the final rule preamble for a summary of the final standards/presumptive standards for reciprocating compressors. See final standards/presumptive standards at 40 CFR 60.5385b and 40 CFR 60.5393c.

Comment: Commenter (2202-Texas Oil & Gas Association (TXOGA)) states that the reciprocating compressor rod-packing measurement standard announced in the December 2022 proposal should be abandoned, and if any standard is issued, it should be consistent with the limits in the November 2021 Notice. The November 2021 Notice explained that the EPA was planning to find that the BSER for reciprocating compressors is to “replace the rod packing” when, “based on annual flow rate measurements,” there are “indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels.”<sup>13</sup> Now, in the December 2022 proposal, the EPA states that the BSER is “replacement of the rod packing and/or other necessary repair and maintenance activities to maintain emissions at or below 2 scfm.”<sup>14</sup>

The commenter (2202-TXOGA) notes that the EPA states that its “BSER analysis is unchanged from what was presented in the November 2021 [Notice],” and describes as a “clarification” its introduction of a numeric standard of 2 scfm.<sup>15</sup> Be it a “clarification” or an actual change, the “major difference” between this standard and what the EPA explained in November 2021 is that, “under this supplemental proposal, owners and operators would be required to maintain emissions at or below the emission limit (emission flow rate of 2 scfm);” whereas, “under the November [Notice], owners or operators would have been required to change out the rod packing only after discovering an exceedance of 2 scfm.”<sup>16</sup> According to the commenter, this is no minor difference.

Upon finalization of this standard of performance, the commenter (2202-TXOGA) states regulated community would be required to actively monitor all reciprocating compressors for a leak flow rate of less than 2 scfm. The commenter provides that it is reasonably anticipated that this will result in significantly increased monitoring costs for owners and operators, yet these costs are not accounted for in the proposal, nor is the analysis of the statutory factors for BSER addressed. Further, additional repair to and replacement of reciprocating compressors would also increase owners and operators’ costs, providing, at best, a de minimis benefit. According to the commenter, this is especially true, when, as the EPA states in its December 2022 proposal, 2 scfm is considered only “indicative” of rod packing failure and does not necessarily mean that such failure has in fact taken place or even that it will likely occur in the near future.<sup>17</sup> Exacerbating the burden is that many companies rent, and do not own, such equipment. The proposal to make exceeding the 2 scfm rate a violation, even though the packing may be perfectly fine and even though emissions would not exceed expected levels that served as basis for the BSER analysis, does not constitute reasoned decision-making. The commenter asserts

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<sup>13</sup> 86 Fed. Reg. at 63,215.

<sup>14</sup> 87 Fed. Reg. at 74,797.

<sup>15</sup> Id.

<sup>16</sup> Id. (emphasis added).

<sup>17</sup> See id. at 74,796 (emphasis added).

that the EPA should return to the BSER for reciprocating compressors as originally described in the November 2021 Notice.

Response II-11-15: Section X.I.1 (Numeric standard versus work practice standard) of the preamble to the final rule details EPA's rationale and reasoning that responds to the numeric standard versus work practice standard comments and establishes final standards/presumptive standards related to reciprocating compressors as work practice standards, including repair and delay of repair requirements.

The EPA maintains as set out in sections XII.E.1.d and 2 of the November 2021 proposal preamble,<sup>18</sup> that annual rod pack flow rate monitoring and replacement of the packing where flow rate monitoring indicates a measurement that exceeds 2 scfm represents BSER for NSPS OOOOb and EG OOOOc for all segments including reciprocating compressors located at centralized productions facilities (with the exception of compressors at stand-alone well sites). Monitoring costs were included in the November 2021 proposed BSER analyses.<sup>19</sup> The analyses assumed the same reciprocating compressor monitoring costs used under Part 98 subpart W information collection request (ICR).<sup>20</sup>

Comment: Commenter (2383-Baker Hughes) recommends against the proposal to trigger rod packing replacement or repair based on a one-size-fits-all leak rate of 2 scfm, because frequent replacement of rod packing will lead to unnecessary compressor blowdowns and emissions. Rather, the commenter recommends tuning the leakage threshold based on the operating parameters of the compressor, mainly flow and pressure. The commenter explains that packing seals always leak some amount of the compressed media, even when newly installed. For larger applications, such as transmission compressors, historical data shows that newly installed packing leaks at a rate of approximately 1 scfm. According to the commenter, the proposed actionable leak rate of 2 scfm will lead to a significant increase in packing replacement for large, transmission sector, compressors. This in turn will lead to a significant increase in compressor blowdowns with associated large volumes of emitted blowdown methane. Before adopting such a proposal, the commenter recommends that EPA analyze the increased volume of methane emissions from more frequent blowdowns compared to increasing the actionable leak rate, especially for the larger transmission compressors.

Response II-11-16: In response to comments received on the December 2022 Proposal, EPA has finalized the performance-based volumetric flow rate standard as a work practice standard under both the NSPS OOOOb and EG OOOOc, including repair and delay of repair provisions (including if there would be a need for a blowdown to conduct repairs). See section XI.I.1 of the preamble to the final rule which provides EPA's rationale and reasoning for finalizing the performance-based volumetric flow rate standard as a work practice standard.

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<sup>18</sup> 86 FR 86 63215-63219, November 15, 2021.

<sup>19</sup> November 2021 TSD. Pgs. 7-12 to 7-14.

<sup>20</sup> Greenhouse Gas Reporting Program (EPA ICR No. 2300.18, OMB Control No. 2060-0629) to the Office of Management and Budget (OMB).

Comment: Commenter (2433-EDF et al) does not support the EPA's proposed change to allow monitoring of reciprocating compressors only every 8,760 operational hours as opposed to annually. The commenter states that an annual monitoring requirement is reasonable and does not impose an undue burden on operators. They note that, while it is true that compressors may not be continuously operated all year at all facilities, the risk of malfunction from compressors that are only operated intermittently is high because nonuse can cause components to shift or corrode while unobserved. Compressors that operate for even 1,000 hours a year have an equally high, if not higher, risk of malfunction or deterioration as compared to compressors that operate continuously. The commenter contends that only requiring compressors to be monitored just once every nine years is unreasonable. According to the commenter, such a monitoring schedule would likely allow for emissions well above the threshold to go unchecked.

Response II-11-17: The EPA acknowledges the commenter's concern, however, the EPA proposed and is finalizing its allowance that performance-based volumetric flow rate monitoring be done based on operational hours as opposed to annually. With regards to the comment that the risk of malfunction from compressors that are only operated intermittently is high because non-use can cause components to shift or corrode while unobserved, the commenter did not provide evidence to support their hypothetical claim. The EPA reiterates its position, as outlined in Section IV.I.1.b of the December 2022 Supplemental Proposal preamble, that it makes sense to require periodic reciprocating compressor flow rate monitoring based on the hours of operation (*i.e.*, 8,760 hours) to allow owners and operators the needed flexibility to plan maintenance for limited-use reciprocating compressors.<sup>21</sup>

Comment: Commenter (2433-EDF et al) states that the EPA should lower the emissions threshold for rod packing replacement in reciprocating compressors. The commenter notes that the EPA has proposed requiring replacement when emissions exceed 2 scfm, which the agency estimates will achieve a 92 percent reduction in emissions for reciprocating compressors in all segments.<sup>22</sup> However, as explained in the Clean Air Task Force's (CATF's) Reciprocating Compressor Cost Memo and Spreadsheet,<sup>23</sup> the EPA likely overestimates the emissions reductions associated with replacement at the 2 scfm threshold, because only compressors with emissions that exceed that threshold will replace rod packing and thus reduce emissions. For compressors with emissions below that threshold, there will be no such reductions.

To ensure emissions are meaningfully reduced based on an annual monitoring program, the commenter (2433-EDF et al) requests that the EPA lower the threshold for replacement to 0.5 scfm, which we estimate will reduce approximately 80 percent of compressor station emissions while remaining highly cost-effective. While the EPA did not estimate the cost-effectiveness of replacement at lower thresholds, the CATF estimates that imposing a 0.5 scfm threshold would entail a cost of \$270/ton of methane not accounting for gas savings, and \$89/ton of methane after accounting for gas savings, at gathering and boosting compressors, which is the highest cost

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<sup>21</sup> 87 FR 74797, December 6, 2022.

<sup>22</sup> Initial TSD, *supra* note 413, at 7-1 through 7-33.

<sup>23</sup> See Lesley Fleischman, Reciprocating Compressor Cost Memo (Jan. 24, 2022) (included as Attachment U to 2022 Joint Environmental Comments, *supra* note 1); Clean Air Task Force, Reciprocating Compressor Cost Spreadsheet (Jan. 24, 2022) (included as Attachment V to 2022 Joint Environmental Comments, *supra* note 1).

segment. Table 19 of their comment letter shows the CATF cost summary for all segments; these abatement costs are very similar to costs for the current NSPS OOOOa requirement for new sources.<sup>24</sup> [Table 19 VOC and Methane Cost of Control (\$/ton) for all Segments (Gathering and Boosting, Processing, Transmission, Storage).] The commenter provides that a detailed description of the cost calculation methodology is an attachment to their comment letter (Reciprocating Compressor Cost Memo and Spreadsheet). The commenter reports that a lower threshold is also in line with standards adopted in Canadian jurisdictions, which, as EPA notes, require rod packing replacement at vent volume thresholds ranging from 0.49 to 0.81 scfm/cylinder.<sup>25</sup>

Response II-11-18: In response to comment requesting that EPA lower the emissions threshold for rod packing replacement, there is insufficient information at this time to support the establishment of a standard based on a lower volumetric flow rate. While EPA can apply costs and emissions based on a lower volumetric flow rate as provided by the commenter, the commenter did not provide evidence that 0.5 scfm represents deterioration of the rod packings, or that it is even achievable with newly replaced rod packings.

Comment: Commenter (2433-EDF et al) states that the EPA should not allow for repair instead of replacement of rod packing unless the emissions threshold is lowered to at least 0.5 scfm. If the EPA maintains the currently proposed emission threshold of 2 scfm, the agency must require replacement of rod packing (as opposed to also allowing for repair). Conversely, if the EPA were to adopt an emissions threshold of 0.5 scfm, then repair of rod packing would offer emissions abatement that is comparable to that of replacing the rod packing. Table 20 of their comment letter shows the projected emissions reductions from rod packing replacement versus repair at both 2 scfm and 0.5 scfm. At a threshold of 2 scfm, merely repairing rod packing offers significantly less emissions reductions than would be possible with replacement.

Response II-11-19: See Response II-11-18 of this Chapter.

Comment: Commenter (2433-EDF et al) requests that EPA develop standards to reduce emissions from compressor exhaust. The commenter states that these emissions are substantial: The commenter estimates 393,355 tons of methane emissions resulting from gathering and boosting compressor exhaust in 2019. The commenter has recommended to EPA in the past, the agency should consider requiring that compressors be driven by turbines or electric motors, since according to emissions factors in the Greenhouse Gas Inventory (GHGI), turbines produce less methane per horsepower-hour than reciprocating internal combustion engines (RICE) by about a factor of 25.<sup>26</sup>

Response II-11-20: The EPA acknowledges the commenter's input. However, the scope of the oil and natural gas industry sources that are subject to NSPS OOOOb standards and EG OOOOc

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<sup>24</sup> Initial TSD, *supra* note 413, at Table 7-9 and 7-10.

<sup>25</sup> 86 Fed. Reg. at 63218.

<sup>26</sup> Sierra Club et al., Comment Letter on New Source Performance Standards: Oil and Natural Gas Sector; Review and Proposed Rule for Subpart OOOO, at 48 (Nov. 30, 2011), <https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-4240>.

presumptive standards excludes the regulation of RICE and was therefore not evaluated under the NSPS OOOOb and EG OOOOc rules.

#### ***11.2.4 Alternative Compliance Option***

Comment: Commenter (2383-Baker Hughes) states that they support the proposed alternative compliance option, 40 CFR 60.5411b(d), of allowing operators to collect the methane and VOC emissions from a reciprocating compressor rod packing using collection system (a closed vent system that meets the requirements of the final emission standard) and to route the rod packing emissions to a process. The commenter recommends that in addition, the EPA allow operators to adjust compressor performance to bring the leak rate down below an established threshold. If performance of the compressor at a lower flowrate or lower pressure meets the needs of the operator, and by adjusting those performance parameters, the leak rate can be held down, this should be a viable mitigating action that allows the operator time to make repairs once seal wear leads to unacceptable performance.

Response II-11-21: The final NSPS OOOOb and EG OOOOc rules require that the volumetric flow rate of each cylinder not exceed 2 standard cubic feet per minute (scfm). If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. Adjusting the performance of the compressor to decrease the cylinder leak rate below 2 scfm per cylinder would be allowed.

With regards to the comment that requests that, if a packing leakage system is in place that captures all packing leakage in a closed loop that routes the leakage away for re-use or sales, then the packing leak rate should not be the trigger for abatement action as there are no emissions connected with the leak rate. As an alternative to having to meet the 2 scfm performance-based emissions standard per cylinder, the final rule allows owners and operators to route emissions from the rod packing via a CVS to a process or to a control device achieving 95 percent control. See sections X.I.1 and 2 of the final rule preamble for a summary of the final reciprocating compressor standards included in NSPS OOOOb and EG OOOOc.

Comment: Commenter (2258-MS) supports the removal of the language “under negative pressure” as part of the requirement of routing rod packing emissions to a process. The commenter requests that additional flexibility be allowed in the regulatory requirements for reducing or controlling rod packing emissions. The commenter states that technology to reduce emissions, such as seal gas recovery, is relatively new and emerging and the regulation should not discourage these options. The commenter explains that these systems will be monitored as fugitive emission sources and the additional requirements of them being closed vent systems does not provide additional value. They note that simply requiring a reduction of 95 percent of emissions and fugitive emissions monitoring should be adequate to verify compliance.

Response II-11-22: With regards to the comment supporting the removal of the language “under negative pressure” from the routing rod packing emissions to a process requirement, this is a supportive comment on an aspect of the December 2022 Proposal that has remained unchanged in the final rule; as such, no response is required.

With regards to the commenter's suggestion that the EPA should allow the option of routing rod packing emissions to a process without the need for owners and operators having to comply with closed vent system requirements, see Response II-11-21 of this Chapter.

See section X.I. of the final rule preamble for a summary of the final standards/presumptive standards for reciprocating compressors. See final standards/presumptive standards at 40 CFR 60.5386b and 40 CFR 60.5393c.

Comment: Commenter (2177-Ute Tribe) responds to the EPA solicitation for comment regarding its assumption that the emissions reduced by requiring the capture of gas and routing to a process are greater than the requirement to maintain the flow rate from the reciprocating compressor rod packing at or below 2 scfm; and on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa by capturing and routing emissions from the reciprocating compressor rod packing to a process.

The commenter (2177-Southern Ute) states that capturing these emissions and routing them to a process may require installation of additional compression equipment. This needs to be assessed on a site-by-site basis and should not just be assumed that it will result in a reduction in emissions. The commenter continues that other regulations (NESHAP ZZZZ, NSPS OOOOa) require the replacement of rod packing, and not the monitoring for rod packing leaks. The commenter notes that this provision has the potential for a source to be required to conduct both rod packing replacement and monitoring, creating unnecessary requirements. The commenter requests that requirements be aligned with other subparts to prevent an unnecessary burden on operators.

Response II-11-23: The commenter suggests that a fixed rod packing replacement schedule under other regulations (specifically, NESHAP ZZZZ and NSPS OOOOa) means that an owner or operator might be required to conduct both rod packing fixed-schedule replacement and monitoring requirements.

While the commenter is correct that there may be overlapping regulations, overlapping of requirements would not occur under NSPS OOOOa and NSPS OOOOb or NESHAP ZZZZ and NSPS OOOOb. If you are a new or modified source subject to NSPS OOOOb, you would not be subject to NSPS OOOOa. And NESHAP ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions and not reciprocating compressors regulated under NSPS OOOOb standards/EG OOOOc presumptive standards. Nonetheless, if an owner or operator is required to change out packing every three years (or every 26,000 hours of operation) on a fixed schedule and must also meet the requirements of NSPS OOOOb, an owner or operator would be required to do monitoring under NSPS OOOOb, but would only be required to conduct more frequent repair or rod packing change-outs if the performance-based volumetric flow rate standard is exceeded.

Comment: In response to EPA no longer including option under the alternative compliance option to route emissions to a control device, commenter (2305-Williams) states that there is a timing concern for facilities that would need to retrofit existing design to accommodate EPA's

proposed rule changes. The commenter notes that supply of these systems is not sufficient to meet current demand even absent this regulatory driver. They add that additional delay in application is also reasonably likely due to the need for reengineering of facility processes. Assuming a facility can be redesigned to route rod packing vents back to process, the capture and return to process is an engineering modification requiring adequate time for a facility to undergo the necessary design and review process to ensure any changes to safety mechanisms and process programs are understood and mitigated.

Response II-11-24: See section XI.I.5 of the final rule preamble for EPA's decision to allow routing of vented emissions to a control device achieving a 95 percent reduction in VOC and methane emissions as an acceptable alternative compliance option under the final NSPS OOOOb standards and EG OOOOc presumptive standards for reciprocating compressors.

### ***11.2.5 BSER Analysis/Emissions/Costs***

Comment: Commenter (2483-INGAA) states that the EPA's BSER analysis did not consider that in some circumstances, rod packing replacement is not sufficient to reduce the emission rate to 2 scfm. In these situations, it may be necessary to conduct a complete "tear down" or to replace the rod also. It is often necessary to replace both a rod and the surrounding rod packing at the same time to ensure there are no differences in the metallurgy of the components that could render them incompatible. Separately, even if replacement of rod packing sufficiently reduces the emissions rate, installation of newer types of lower-emissions packing requires pulling out the rod, which requires additional time.

Commenter (2483-INGAA) notes that these activities have a much higher cost than replacing the rod packing, potentially making their cost effectiveness unreasonable or at a minimum affecting repair schedule. Such a scenario cannot be predicted or planned for in advance, as there are multiple factors that affect the type of repair that is appropriate in each instance. In those instances where rod packing replacement does not sufficiently reduce the emission rate, an operator may have to remove the rod assembly and piston, and potentially replace the rod as well as components like the piston rings, rider bands, and the compressor liner. The costs of such a replacement project could approach \$100,000. The commenter suggests that the EPA analyze these situations to determine whether they are cost effective and, if not, the EPA should adopt provisions to either exempt these situations from the limitation requirements or that otherwise address them in a cost-effective manner, with an appropriate schedule allowed.

Response II-11-25: In situations where it might be necessary to complete a "tear down" or to replace the rod (and not just the rod packing), that would not be considered an added emissions control cost, but an indication of equipment failure/age/malfunction that impacts emissions. Owners and operators would need to address these major issues without regard to the NSPS.

Comment: Commenter (2383-Baker Hughes) suggests condition monitoring as BSER. According to the commenter, there are commercially available condition monitoring solutions for reciprocating compressors, considering performance parameters, that can be used to predict the need for seal replacement in a timelier manner than annual seal leak monitoring, and should be considered as a BSER for minimizing compressor seal leakage for new and existing



reciprocating compressors. As one of the oldest compressor designs, reciprocating compressors enjoy unique capabilities such as broad capacity control ranges, interstage cooling, the flexibility to efficiently compress gas regardless of mole weight or k value, and extremely high compression ratios. Consequently, the commenter reports that they are an ideal fit for selected applications such as hydrogen compression. However, reciprocating compressors suffer from one very serious drawback: higher maintenance costs. In fact, compared to similarly sized centrifugal compressors, reciprocating compressors can consume as much as five times the amount of maintenance dollars. Smart compression condition monitoring technology monitors performance and other analytics of the compressor to ascertain if maintenance is required and can adjust performance of the compressor to optimize performance when degradation has been sensed. Operators can optimize performance while operating below a prescribed emission threshold rather than relying on annual detection to signal the need to corrective action.

Response II-11-26: Smart compression condition monitoring technology that monitors the performance of the compressor and optimizes performance when degradation has been sensed is certainly allowed, but not required under the final NSPS OOOOb standards or EG OOOOc presumptive standards. Owners and operators can use this option as an internal operational and maintenance procedure to constantly check the status of integrity of the rod packings to ensure that, when the periodic measurement is made that the flow rate is below 2 scfm. The EPA has insufficient information to evaluate condition monitoring technology as BSER.

Comment: Commenter (2196-Massengale) provides the following analysis:

A failed rod packing @ 2 scfm is (~56.63 l/m) or 1,051,188 standard cubic feet (scf)/year (yr) or 5.36 pounds (lbs)/hour (hr) or 46,953.6 lbs/yr CH<sub>4</sub>.

- EPA “Natural Gas Star Circular 2006: Reducing Methane Emissions From Compressor Rod Packing Systems” published data on Rod packing venting and NG compression infrastructure said there are about 51,000 compressors in natural gas industry. For example, purposes, let’s assume there are 60,000 compressors as of now.
- If we assume (for example purposes) 4 rod packing vents per compressor. That is 240,000 rod packing vents.
- 240,000 “Vents” x 5.36 lbs/hr (vent failure) x 8760 hrs/yr = 11,268,864,000 lbs per year if they all failed @ 2 scfm all year - worst-case scenario (i.e., failed for a year before being found).
- NSPS OOOO required Rod packing be replaced every “3 years” ... assume 33% fail per year and assume that they are found halfway thru a yearly cycle.
- 11,268,864,000 lbs x 33% failure rate x 0.5 (failure found half-way thru 1 yr fail cycle) = 1,859,362,560 lbs or 929,681 tons/yr CH<sub>4</sub> from rod packings.

The commenter (2196-Massengale) contends that leaks can be found 4 times faster due to 40 CFR 60.5397 quarterly optical gas imaging (OGI) frequency (with little or no additional costs) by requiring that the rod packings be checked at the associated 40 CFR 60.5397 frequency and if no leak “nothing is done” as far as volumetric flow rate requirement as indicated in 40 CFR 60.5385b(c)(2)(iv). We can argue mass numbers and validity of assumptions above, but the

benefit of finding and stopping rod packing leaks faster with very little to NO additional or associated cost should be considered. The commenter recommends that rod packing vents be inspected with OGI at the frequency (and most times same time as) required in 40 CFR 60.5397b (which will be quarterly in majority of the cases).

Using the same assumption scenario above:

- A leak (averaging) could be found half-way thru a quarterly cycle or 45 days.
- As opposed to ~182.5 days (1/2 yearly cycle), which is approximately 25% of the emissions above (all else being equal). Or 232,420 tons per year (tpy) instead of 929,681 tpy. Or a reduction in emissions of 697,261 tpy. Or, a 75 percent reduction.

Thus, the commenter (2196-Massengale) adds that whatever numbers we choose in our modeling of emissions above, finding leaks sooner with little or no additional costs (excluding recordkeeping) could reduce rod packing venting by percent over proposal.

Response II-11-27: The EPA acknowledges the commenter's illustrative analysis. While the EPA agrees that more frequent monitoring could identify leaks sooner in some cases, we believe that the monitoring frequency based on 8,760 hours of operation is sufficient.

### **11.3 NSPS OOOOb and EG OOOOc Compliance Issues**

[*Note:* Most of the comments provided on the BSER for NSPS OOOOb also apply to EG OOOOc. For specific comments that just apply to EG OOOOc, see section 11.4 of this Chapter).]

#### ***11.3.1 Test Methods and Procedures (Apply to Both NSPS OOOOb and EG OOOOc)***

Comment: Commenter (2227-WEA) states that volumetric flow measurements must be conducted using rate meters conforming to EPA Method 2D. However, they note that Method 2D does not list specific rate meters or technologies that could be used and there are few meter technologies commercially available to measure low volumetric flow rates from very small vents. The commenter notes that annual flow measurements present many complexities and costs.

Commenter (2326-AXPC) proposes an alternative to conducting the annual inspection via Method 2D. The commenter proposes, that in lieu of annual Method 2D test, an operator can utilize an OGI camera as a screening tool to scan the rod packing vent during the required fugitive emission surveys – e.g., quarterly for compressor stations subject to NSPS OOOOb or EG OOOOc. Under this alternative, the commenter notes that, if the operator detects no emissions with an OGI camera during a routine fugitive emissions survey, no action is required because the volumetric flow rate from the compressor cylinder is assumed to be well below the proposed 2 scfm limit, given that OGI cameras are capable of detecting hydrocarbon emissions well below a 2 scfm flowrate. However, if the operator observes emissions with the OGI camera, the operator would confirm within 30 days that the emissions are below the 2 scfm limit via a high-volume flow sampler using Method 2D. The commenter believes this proposal is very

conservative given that OGI cameras can detect emissions much lower than the proposed 2 scfm. The commenter believes this is a cost-effective alternative because it allows operators to take advantage of staff already onsite to conduct the fugitive emission survey, and the OGI camera can detect emissions well below the proposed threshold. Further, this approach may alleviate high volume flow sampler supply issues noted just below.

Response II-11-28: EPA Method 2D describes how to conduct the measurement of flow through direct measurement or by using pressure drop measurements to calculate flow. The method allows for many different types of measurement devices, including but not limited to rotameters and orifice plates, to accomplish the measurement, as long as the device measures the gas flow (volume rate or pressure drop) accurately. Because EPA Method 2D is not limiting in the types of measurement devices that can be used, we believe the method provide owners and operators with enough flexibility to choose the type of measurement device that works best for the situation.

In response to commenter requesting an alternative approach to conducting inspection via Method 2D, the December 2022 Supplemental Proposal regulatory text for reciprocating compressors under NSPS OOOOb and EG OOOOc does not require volumetric flow rate monitoring if screening for emissions or leaks from the reciprocating compressor rod packing using optical gas imaging (OGI) or Method 21 does not indicate a leak. This has been maintained in the final NSPS OOOOb and EG OOOOc requirements. See final test methods and procedures for reciprocating compressors at 40 CFR 60.5385b and 40 CFR 60.5405c.

Comment: Commenter (2282-Kinder Morgan, Inc.) states that the EPA should allow the use of calibrated bags, anemometers, as well as any other suitable measurement methods for measuring emission rates from rod packing. They add that EPA should also allow the use of anemometers and calibrated bags for flow rate measurement from rod packing. Allowing the use of anemometers and calibrated bags would be more straightforward for operators to implement and would be lower cost, while still providing reliable and robust data. As they noted on their comments on centrifugal compressor monitoring, they note that anemometers are a cost-effective and accurate measurement tool that the EPA should allow for measurements from rod packing. The commenter incorporates the same arguments that they provided for centrifugal compressor monitoring with respect to measurements from rod packing.

In addition, the commenter (2282-Kinder Morgan, Inc.) reports that they have successfully utilized calibrated bags for measuring emissions from rod packing for reporting under Subpart W. This measurement method is allowed by the EPA in Subpart W,<sup>27</sup> and has been successful implemented by the commenter for nearly two decades. Thus, in addition to anemometers, the commenter requests the EPA allow the use of calibrated bags for measuring emissions from rod packing.

The commenter (2282-Kinder Morgan, Inc.) requests that the EPA expressly allow the use of any other Administrator-approved measurement method, either already approved pursuant to Subpart W, or independently approved by the Administrator pursuant to application of any final version of the NSPS Rule. The commenter proposes the following specific rule changes below and in the

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<sup>27</sup> See, e.g., 40 CFR 98.233(p)(2)(i)(A), (p)(2)(ii)(A), (p)(2)(iii)(B).

Exhibit A of their comment letter to address their concerns (underlined text reflects new text and struck out text reflects deleted text) [Track change versions of regulatory language and reasoning four suggested changes included with their comment letter.]:

- *40 CFR 60.5393c(b)(1)*<sup>-28</sup>

(b) You must determine the volumetric flow rate from your reciprocating compressor rod packing as specified in paragraph (b)(1) or (2) of this section.

(1) For reciprocating compressor rod packing equipped with an open-ended vent line on compressors in operating or standby pressurized mode, determine the volumetric flow rate of the rod packing using one of the methods specified in paragraphs (b)(1)(i) through ~~(viii)~~ of this section.

(i) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a high-volume sampler according to methods set forth in §60.5405c(c).

(ii) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a temporary or permanent meter, according to methods set forth in §60.5405c(b).

(iii) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a hotwire or vane anemometer according to the methods set forth in §98.234(b).

(iv) Determine the volumetric flow rate at standard conditions from the open-ended vent line using a calibrated bag according to the methods set forth in §98.234(b).

(iv) Determine the volumetric flow rate at standard conditions from the open-ended vent line using an alternative method, as set forth in §60.5405c(d).

~~(viii)~~ Any of the methods set forth in §60.5405c(a) to screen for leaks and emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected according to any of the methods in §60.5405c(a). If emissions are detected using the methods set forth in §60.5405c(a), then you must use one of the methods specified in paragraph (b)(1)(i) and (b)(1)(ii) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5405c(a), then you may assume that the volumetric ~~emissions~~ flow rate ~~are~~ is zero.

- *40 CFR 60.5393c(b)(2)*<sup>-29</sup>

(2) For reciprocating compressor rod packing not equipped with an open-ended vent line on compressors in operating or standby pressurized mode, you must determine the

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<sup>28</sup> The NSPS OOOOb section to which this change should also apply is 40 CFR 60.5385b(b)(1).

<sup>29</sup> The NSPS OOOOb section to which this change should also apply is 40 CFR 60.5385b(b)(2).

volumetric flow rate of the rod packing using the methods specified in paragraphs (b)(2)(i) and (iiv) of this section.

(i) You must use the methods described in §60.5405c(a) to conduct leak detection of emissions from the rod packing case into an open distance piece, or, for compressors with a closed distance piece, you must conduct annual leak detection of emissions from the rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing. You must measure emissions found in paragraph (b)(2)(i) of this section using:

(ii) ~~You must measure emissions found in paragraph (b)(2)(i) of this section using a~~ A meter or high-volume sampler according to methods set forth in §60.5405c(b) or (c).

(iii) A hotwire or vane anemometer according to the methods set forth in §98.234(b).

(iv) A calibrated bag according to the methods set forth in §98.234(b).

(v) An alternative method, as set forth in §60.5405c(d).

- *40 CFR 60.5393c(c)* (underlined text reflects new text and struck out text reflects deleted text)-<sup>30</sup>

(c) For conducting measurements on manifolded groups of reciprocating compressor designated facilities rod packing, you must determine the volumetric flow rate from ~~reciprocating compressor~~ the rod packing vent as specified in paragraph (c)(1) and (2) of this section.

(1) Measure at a single point in the manifold downstream of all ~~compressor~~ rod packing inputs and, if practical, prior to comingling with other non-~~compressor~~ rod packing emission sources.

(2) Determine the volumetric flow rate of the rod packing at standard conditions from the common stack using one of the methods specified in paragraph (c)(2)(i) through (iv) of this section.

(i) A temporary or permanent flow meter according to the methods set forth in §60.5405c(b).

(ii) A high-volume sampler according to methods set forth §60.5405c(c).

(iii) A hotwire or vane anemometer according to the methods set forth in §98.234(b).

(iv) A calibrated bag according to the methods set forth in §98.234(b).

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<sup>30</sup> The NSPS OOOOb section to which this change should also apply is 40 CFR 60.5385b(c)(2).

(iiiiv) An alternative method, as set forth in §60.5405c(d).

(ivi) Any of the methods set forth in §60.5405c(a) to screen for emissions. For the purposes of this paragraph, emissions are detected whenever a leak is detected when using any of the methods in §60.5405c(a). If emissions are detected using the methods set forth in §60.5405c(a), then you must use one of the methods specified in paragraph (c)(2)(i) through (iiiv) of this section to determine the volumetric flow rate. If emissions are not detected using the methods in §60.5405c(a), then you may assume that the volumetric ~~emissions-flow rate are~~ is zero.

Response II-11-29: EPA disagrees with the commenter. While we acknowledge that the methods suggested by the commenter are allowed in 40 CFR part 98 subpart W and are adequate for estimating emission inventories, as noted in the December 2022 Supplemental Proposal, these types of measurements are not as well defined or prescriptive as the methods EPA generally requires for demonstrating compliance with a standard. As such, we are not updating the final rule to include these additional types of measurements.

Comment: Commenter (2399-GPA, 2428-API)<sup>31</sup> states that high-volume samplers should be calibrated according to manufacturer specifications. The commenter suggests that the EPA's detailed calibration requirements for high-volume samplers be removed and replaced with a more general requirement that samplers be calibrated in accordance with the manufacturer's specifications. The commenters note that daily field calibration of methane concentrations and volumetric flow rate vary by manufacturer such that one set of calibration instructions is not appropriate for all high-volume samplers and should not be subject to a universal rule or standard.

Response II-11-30: EPA disagrees with the commenters and is maintaining the calibration requirements from the proposed rule. The approach we are finalizing is performance-based and designed to verify the measurement system for its application in the rulemaking. EPA also notes that if a manufacturer design is not compatible with the requirements in the final rule, the owner or operator may petition the Administrator for an alternative test method under §60.8(b).

Comment: Commenter (2196-Massengale) states that the oil and gas rule states in every "standard citation for each affected facility" that it is a "GHG and VOC" standard. Then we go to the 40 CFR 60.5386b which is "the test methods and procedures I must use for my centrifugal compressor and reciprocating compressor affected facilities" .... which is regulated by 40 CFR 60.5385b - What GHG and VOC standards apply to reciprocating compressor affected facilities ..... it becomes a methane (or GHG) only test method. The commenter suggests that the EPA strive not to limit or choose specific instrument manufacturers when specifying equipment requirements for test methods and procedures. They state that this is a GHG and VOC rule. As such, the commenter notes that specifying that the sensor should be methane only is counter to the rule itself. Historically, the commenter notes that sensors have been VOC sensors, though they always have been calibrated to methane in the same fashion that the legacy Method 21 VOC analyzers have always been and more recently required (to be calibrated to methane).

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<sup>31</sup> API endorsed comments submitted by GPA.

Manufacturers have recently begun making methane only sensors due to recent focus on “GHG’s/Global warming”. A VOC sensor that is calibrated to methane that is reading a natural gas or field gas line should be acceptable if it meets the other criteria in this section. According to the commenter, by codifying a “methane selective or specific sensor” the EPA is “choosing a winner”, or limiting or eliminating competition that will ultimately drive technology prices down. Legacy GHG programs have allowed VOC sensors for the GHG rod packing testing programs and have come up with calculation procedures to account for the mixed streams that are inevitably present in our industry. The commenter contends that methane specific sensors will underestimate emissions when used for field gas. Methane concentrations (percent) in field gas can be in the high 70’s (percent) with remainder being mostly C2 and C3 [hydrocarbons] with much lower amounts of C4 thru C6 or C7 [hydrocarbons].

The commenter (2196-Massengale) recommends that the EPA allow the use of a methane specific or VOC sensor calibrated to methane in High volume sampler, and recommends the following rule text changes to address this issue:

*40 CFR 60.5386b(c)(3)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b*: [What test methods and procedures must I use for my reciprocating compressor affected facilities?]

*40 CFR 60.5386b (c)(3)(i)*: Deals with a methane specific sensor, if using a methane specific sensor. *NOTE*: A methane specific sensor will underestimate emissions from field gas. Though the amount of underestimation from field gas compressors would vary based on actual field gas composition.

*40 CFR 60.5386b(c)(3)(ii)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b(c)(3)(iii)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b(c)(5)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b(c)(5)(i)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b(c)(6)(iii)*: Replace “Methane” with “VOC or Methane”

*40 CFR 60.5386b(c)(6)(iv)*: In the calculation, when using a “VOC sensor” that is calibrated to methane all readings are referenced as methane for the purposes of determining 2 scfm compliance level. The VOC sensor reading can be input directly into this equation and result would be a total VOC reading as methane which would be more representative of leak rate (when testing field gas compressor rod packing vents). It is “my opinion” that we not try to over-calculate (or over-think) this calculation procedure. Input the value ... keeping in mind all the of the high-volume samplers being developed take the flow rate and concentration and give leak rate (i.e., Q) using the procedure referenced in this citation. Thus, the equipment manufacturer’s give “Q” in units that can be selected from a menu setting. *NOTE*: 2 of the 3 or 4 Hi volume samplers tested at

METEC [Methane Emissions Technology Evaluation Center] are Methane only sensors. The other was a VOC detector.

Response II-11-31: EPA disagrees with the commenter. We are finalizing the requirement, as proposed that the high-volume sampler must have a sensor that is selective to methane. As the commenter notes, methane is the predominant constituent of the gas stream, and as such, it is appropriate to use methane emissions as a surrogate when determining emissions from the compressor. Additionally, the methane sensors used with the high-volume samplers are generally more reliable than other sensors that would be used for VOC measurement.

### ***11.3.2 Clarification of Compliance Deadlines***

Comment: Commenters (2399-GPA, 2428-API)<sup>32</sup> state that there are certain conflicting compliance deadlines which require clarification. Specifically, the commenters note that there are portions of the proposed regulatory text that include compliance dates that are inconsistent with other portions of the text that they cross-reference. The commenters urge the EPA to resolve these conflicting dates before issuing any final rule.

- Proposed 40 CFR 60.5370b(a)(1)(i) requires compliance with 40 CFR 60.5385b(a)(1) on or before 12 months after publication of the final rule or 12 months after the source's initial startup, whichever is later. This is inconsistent with proposed 40 CFR 60.5385b(a)(1) which requires owners and operators to "conduct your first volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after" the final rule publication date "or on or before 8,760 hours of operation after startup, whichever is later." The EPA should clarify that the compliance timeline referenced in proposed 40 CFR 60.5370b(a)(1)(i) should be on or before 8,760 hours of operation after either the final rule publication date or the startup date, whichever is appropriate.
- Proposed 40 CFR 60.5370b(a)(1)(ii) requires compliance with proposed 40 CFR 60.5385b(a)(2) within 30 days after compliance with proposed 40 CFR 60.5385b(a)(1) (referenced above). This 30-day compliance date, however, is inconsistent with proposed 40 CFR 60.5385b(a)(2). That requires owners and operators to "conduct subsequent volumetric flow rate measurements from your reciprocating compressor on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with the 2 scfm volumetric flow rate." The EPA should clarify that the compliance date referenced in proposed 40 CFR 60.5370b(a)(1)(ii) should be 8,760 hours of operation, as identified in proposed 40 CFR 60.5385b(a)(2).
- Proposed 40 CFR 60.5370b(a)(1)(iii) requires compliance with proposed 40 CFR 60.5385b(a)(3) upon initial startup. However, there is no 40 CFR 60.5370b(a)(3) in the proposed regulatory text. The EPA should clarify whether 40 CFR 60.5370b(a)(3) is missing or if proposed 40 CFR 60.5370b(a)(1)(iii) should be deleted. This would impact 40 CFR 60.5370b(a)(1) as well, which requires compliance with 40 CFR

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<sup>32</sup> API endorsed GPA comments.



60.5370b(a)(1)(iii). If proposed 40 CFR 60.5370b(a)(1)(iii) is deleted, that should be noted in proposed 40 CFR 60.5370b(a)(1) by deleting the reference.

- Proposed 40 CFR 60.5415b(g) requires that reciprocating compressors complying with proposed 40 CFR 60.5385b(d) must demonstrate continuous compliance with 40 CFR 60.5415b(g)(4) through (g)(6). However, there are no paragraphs (g)(5) or (g)(6) in the proposed regulatory text. The EPA needs to clarify if paragraphs (g)(5) and (6) are real requirements that are missing from the regulatory text or if the text should be changed to only list paragraph (g)(4).

Response II-11-32: The EPA agrees that clarification of compliance deadlines is needed. The EPA has made the following clarifications:

- The EPA has made clarifying revisions to the language of 40 CFR 60.5370b(a)(1)(i) as follows:

(i) You must comply with the requirements of §60.5385b(a)(1) and (d)(3) on or before 8,760 hours of operation after [INSERT DATE 60 DAYS AFTER PUBLICATION OF FINAL RULE IN THE FEDERAL REGISTER], on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever is later; and
- The EPA has made clarifying revisions to the language of 40 CFR 60.5370b(a)(1)(ii) as follows:

(ii) You must comply with the requirements of §60.5385b(a)(2) within 8,760 hours after compliance with §60.5385b(a)(1) and (d)(3).
- The EPA has made clarifying revisions to the language of 40 CFR 60.5370b(a)(1)(iii) as follows:

(iii) You must comply with the requirements of §60.5385b(d)(1) and (2) for your reciprocating compressor upon initial startup.
- Several revisions were made to 40 CFR 60.5415b(g) in the final rule and the referencing issue identified by the commenter is no longer an issue.

### ***11.3.3 Timeline for Repair or Replacements (Apply to Both NSPS 0000b and EG 0000c)***

Comment: Several commenters (2258-MSA, 2282-Kinder Morgan, Inc., 2305-Williams, 2366-BHE, 2399-GPA, 2428-API, 2483-INGAA) state that the rule should clarify the required compliance obligations, specifically, what is required when annual monitoring yields a measured flow rate for an individual cylinder that exceeds 2 scfm. The commenters recommend the rule provide a proposed timeline for repair or replacements, as well as delay of repair provisions, consistent with nearly all other NSPS drafted by the EPA.

According to commenter (2483-INGAA), because rod packing replacement is a major

maintenance activity that can be undertaken only during a shutdown, the EPA should make clear in the regulatory language that rod packing replacement would be required at the next planned shutdown for maintenance after such a measurement. The EPA should revert to a work practice that requires timely replacement of rod packing after the emission rate is measured to exceed 2 scfm and provide a suitable delay of repair provision.

According to commenters (2282-Kinder Morgan, Inc., 2399-GPA, 2428-API),<sup>33</sup> a delay of repair provision in such a regulatory scheme appropriately recognizes potential issues with obtaining necessary parts or equipment in the time required to make repairs or where weather makes compressors in remote areas inaccessible. This would be consistent with multiple federal fugitive monitoring programs (specifically NSPS VVa, and NSPS OOOOa) and California regulations. See also 87 Fed. Reg. at 74,798 (acknowledging the need for a delay of repair option for “scenarios beyond the owner or operator’s control”). Thus, the commenters note that a delay of repair option is a commonly used and well understood compliance option for certain scenarios. The commenters had diverse recommendations as to the length of delay as noted below:

- Commenter (2282-Kinder Morgan, Inc.) suggests that the EPA allow an operator to repair or replace the rod packing measuring above the volumetric flow rate threshold within 90 days from the date of the applicable measurement. However, such a requirement would only be triggered after a measurement required every 8,760 hours of operation. Additionally, and as an exception to the 90-calendar day timeframe, the agency must provide a delay of repair provision if the repair or replacement would require a vent blowdown, or otherwise be infeasible or unsafe, until the next process unit shutdown.
- Commenter (2428-API) recommends that 40 CFR 60.5380b and 60.5385b be amended to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with 40 CFR 60.5397b(h)(3).
- Commenter (2483-INGAA) recommends that repair be required no later than the next scheduled compressor station shutdown for maintenance.
- Commenter (2399-GPA) suggests repair within 720 operating hours which would be more consistent with the hours of operation limitations in proposed 40 CFR 60.5385b(a)(1) and (2).
- Commenter (2305-Williams) requests a two-year delay of repair timeline that matches the leak monitoring program for streamlining. Additionally, the time to repair rod packing has all similar repair timing constraints as fugitive components.

Commenters (2282-Kinder Morgan, Inc. I, 2483-INGAA) propose specific regulatory language revisions to implement the requested work practice approach and delay of repair provision.

The following revised rule language is proposed by one commenter (2483-INGAA) for the proposed new section 40 CFR 60.5385b(a) and 60.5393c(a) (underlined text reflects new text and struck out text reflects deleted text):

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<sup>33</sup> API endorsed GPA comments.

~~(a) The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm). You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section and determine the volumetric flow rate in accordance with paragraph (b) of this section. If the volumetric flow rate, measured in accordance with paragraph (b) of this section, for a rod packing exceeds 2 standard cubic feet per minute (scfm), or if the combined volumetric flow rate, measured in accordance with paragraph (b) of this section, for multiple rod packings that are manifolded together exceeds 2 scfm multiplied by the number of rod packings, the rod packing or packings must be repaired as provided in paragraph (a)(3) of this section.~~

A new paragraph 40 CFR 60.5393c(a)(3) and 60.5385b(a)(3) should be added as follows (underlined text reflects new text):

(3) The rod packing repair must be conducted no later than the next scheduled compressor station shutdown for maintenance. Delay of repair beyond the next compressor station shutdown for maintenance is allowed for a reciprocating compressor rod packing, if rod packing replacement is necessary during the compressor station shutdown for maintenance, rod packing supplies have been depleted, and rod packing supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next compressor station shutdown for maintenance will not be allowed unless the next compressor station shutdown for maintenance occurs sooner than 6 months after the first compressor station shutdown for maintenance. You must conduct volumetric flow rate measurements from each repaired rod packing using the methods specified in paragraph (b) of this section within 15 days after the repair to document that the rate has been reduced to less than 2 scfm per rod packing.

The following revised rule language is proposed by commenter (2282-Kinder Morgan, Inc.) for reciprocating compressors to address their concerns:

40 CFR 60.5393c(g) and 60.5393c(g)(1)<sup>34</sup> suggested additions include (underlined text reflects new text):

(g) If the results of the initial (§60.5410c(d)) or continuous (§60.5415c(f)) compliance measurement demonstrate that the rod packing flow rate is greater than 2 scfm, you must repair or replace the rod packing within 90 days from the date of the initial or continuous flow rate measurement.

(1) If the repair or replacement is technically infeasible, would require a vent blowdown, a process unit or facility requires shutdown, parts or materials are unavailable, or it would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled process unit or facility shutdown for maintenance, after a scheduled vent blowdown, or within 2 years, whichever is earliest. For purposes of this paragraph (d)(1),

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<sup>34</sup> The Subpart OOOOb section to which this change should also apply is §60.5385b.

a vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

Response II-11-33: In response to comments received on the December 2022 Proposal, EPA has finalized the performance-based volumetric flow rate standard as a work practice standard under both the NSPS OOOOb and EG OOOOc, including repair and delay of repair provisions. See section XI.I.1 of the preamble to the final rule which provides EPA's rationale and reasoning for finalizing the performance-based volumetric flow rate standard as a work practice standard.

As such, and in consideration of the comments above, the EPA has included the following repair and delay of repair requirements in 40 CFR 60.5385b(a)(3) and 40 CFR 60.5393c(a)(3):

(3) The rod packing must be repaired or replaced within 90 calendar days after the date of the volumetric emissions measurement that exceeded 2 scfm per cylinder. You must conduct follow-up volumetric flow rate measurements from compressor vents using the methods specified in paragraph (b) of this section within 15 days after the repair (or rod packing replacement) to document that the rate has been reduced to less than 2 scfm per cylinder. Delay of repair will be allowed if the conditions in paragraphs (a)(3)(i) or (ii) of this section are met.

(i) If the repair (or rod packing replacement) is technically infeasible, would require a vent blowdown, a compressor station shutdown, or would be unsafe to repair during operation of the unit, the repair must be completed during the next scheduled compressor station shutdown for maintenance, after a scheduled vent blowdown, or within 2 years of the date of the volumetric emissions measurement that exceeds the applicable required flow rate per cylinder, whichever is earliest. A vent blowdown is the opening of one or more blowdown valves to depressurize major production and processing equipment, other than a storage vessel.

(ii) If the repair requires replacement of the rod packing or part, but the replacement cannot be acquired and installed within the repair timelines specified under this section due to the condition specified in paragraph (a)(3)(ii)(A) of this section, the repair must be completed in accordance with paragraph (a)(3)(ii)(B) of this section and documented in accordance with §60.5420b(c)(5)(viii) through (x).

(A) Rod packing or part supplies had been sufficiently stocked but are depleted at the time of the required repair.

(B) The required rod packing or part replacement must be ordered no later than 10 calendar days after the reciprocating compressor is added to the delay of repair list. The repair must be completed as soon as practicable, but no later than 30 calendar days after receipt of the replacement rod packing or part, unless the repair requires a compressor station shutdown. If the repair requires a compressor station shutdown, the repair must be completed in accordance with the timeframe specified in paragraph (a)(3)(i) of this section.

## 11.4 EG OOOOc Proposed BSER

[**Note:** Many of the comments provided for reciprocating compressors included in sections 11.1 through 11.3 of this Chapter would also apply to the reciprocating compressor requirements proposed to be regulated under EG OOOOc. This section provides comments that were submitted on the proposed reciprocating compressor requirements that focused on EG OOOOc.]

### 11.4.1 Applicability

Comment: Commenter (2173-Northeast Natural Energy LLC (NNE)) states that for existing RICE engines under EG OOOOc the operator must determine if vent emissions exceed 2 scfm w/8,760 hours of the effective date of the approved state plan. The commenter suggests that this seems to conflict with the "up to three years compliance date" language found elsewhere in the proposal. The commenter asserts that the EPA needs to clarify why they do not defer to whatever compliance date is in the approved state plan.

Response II-11-34: The EG OOOOc presumptive standards (nor the NSPS OOOOb standards) for reciprocating compressors do not apply to Reciprocating Internal Combustion Engines (RICE) engines. See Compliance Requirements for Stationary Engines (including RICE) at <https://www.epa.gov/stationary-engines/compliance-requirements-stationary-engines>.

Owners or operators of reciprocating compressor designated facilities under the final rule must conduct their first volumetric flow rate measurements from their reciprocating compressor cylinder vents on or before 8,760 hours of operation after the effective date of an approved state or tribal plan, or on or before 8,760 hours of operation after last rod packing replacement, or on or before 8,760 hours of operation after startup, whichever is later. Owners or operators must conduct subsequent volumetric flow rate measurements from their reciprocating compressor cylinder vents on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with a volumetric flow rate of 2 scfm per cylinder (or a combined cylinder emission flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever is later.

### 11.4.2 Proposed Standards

Comment: Commenters (2305-Williams, 2399-GPA, 2428-API)<sup>35</sup> state that the proposed rules for reciprocating compressors need to consider the full costs and technical challenges with retrofitting each existing reciprocating compressor cylinder for monitoring ports. Each cylinder does not necessarily have its own vent. There would need to be alterations made to the piping to allow for monitoring to be conducted on a per-cylinder basis. The costs required to add new piping so each cylinder has its own vent and install monitoring ports have not been considered. Should the EPA choose to move forward with a proposed rule, the commenter assert that the

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<sup>35</sup> API endorses GPA comments.

EPA should issue guidelines allowing a phased approach to adequately account for port installation.

Response II-11-35: The final rule does not require that each cylinder be equipped with a monitoring port. Individual cylinders can be manifolded to a single open-ended vent line/vent, where the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. Further, EPA proposed in the December 2022 Supplemental Proposal (and is maintaining in the final rule) that an owner or operator does not have to conduct volumetric flow rate monitoring if screening for emissions or leaks from the reciprocating compressor rod packing using OGI or Method 21 does not indicate a leak. See final standards/presumptive standards at 40 CFR 60.5386b(a) and 40 CFR 60.5405c(a) test methods and procedures for reciprocating compressors.

In addition, as an alternative to the reciprocating compressor performance-based volumetric flow rate per cylinder presumptive standard, the final EG OOOOc reciprocating compressor requirements allow owners or operators to meet several other compliance options to meet the final NSPS OOOOb standards and EG OOOOc presumptive standards.

Comment: Commenter (2218-Texas Commission on Environmental Quality (TCEQ)) states that the proposed requirements for several types of designated facilities are economically unreasonable and should be revised. The EPA's Oil and Gas Control Techniques Guidelines (CTG) model rule and current TCEQ rules have three control options for reciprocating compressors, including two that simply impose time limits on packing change-outs. The commenter states that the proposed 40 CFR 60.5393c requires packing volumetric flow rate measurements for all affected reciprocating compressors, regardless of when the packing change-outs last occurred. This is unnecessarily burdensome for sources with recently changed packing.

Response II-11-36: The EPA evaluated this and other similar comments. It was not the EPA's intent for affected reciprocating compressors to be required to conduct volumetric flow rate measurements where sources recently changed rod packing. The final EG OOOOc presumptive standards have been revised to clarify that an owner or operator must conduct their first volumetric flow rate measurements from their reciprocating compressor cylinder vents on or before 8,760 hours of operation after the effective date of an approved state or tribal plan, on or before 8,760 hours of operation after last cylinder rod packing replacement, or on or before 8,760 hours of operation after startup, whichever is later. Similarly, owners or operators are required to conduct subsequent volumetric flow rate measurements from reciprocating compressor cylinder vents on or before 8,760 hours of operation after the previous measurement which demonstrates compliance with a volumetric flow rate of 2 scfm per cylinder (or a combined cylinder emission flow rate greater than the number of compression cylinders multiplied by 2 scfm), or on or before 8,760 hours of operation after last rod packing replacement, whichever is later.

## **11.5 Regulation Text Correction**

Comment: Commenter (2298-Pioneer, 2326-AXPC, 2428-API) seeks clarification on a missing cross-referenced section in the reciprocating compressor proposed requirements. Specifically,

they requested that EPA clarify the rule text of 40 CFR 60.5370b(a)(1)(iii), which cross-references a non-existent 40 CFR 60.5385b(a)(3).

Response II-11-37: The EPA evaluated the cross-reference issue identified by the commenters. The EPA has revised 40 CFR 60.5370b(a)(1)(iii) to correctly reference 40 CFR 60.5385b(d) and not 40 CFR 60.5385b(a)(3) in the final rule.

## Chapter 12. Equipment Leaks at Natural Gas Processing Plants

### 12.1 Monitoring Requirements

#### *12.1.1 Inspection Frequency*

Comment: Commenter (2211-Lambda Energy Resources LLC) urges EPA to consider semi-annual monitoring, rather than the proposed bi-monthly surveys for greenhouse gas (GHG) emissions, which would impose significant and unnecessary additional costs on plant operations. The commenter states that they currently employ leak detection and repair (LDAR) monitoring and monitor most components quarterly using EPA Method 21, as well as monitoring for GHG annually with optical gas imaging (OGI) technology. The commenter believes that these existing monitoring programs have proven to be effective and have resulted in minimal emissions. The commenter also urges the EPA to consider delay of repair (DOR) leniency in the event GHG components are found leaking and cannot be repaired or replaced without a process unit shutdown.

Response II-12-1: Regarding the monitoring frequency for OGI monitoring, the EPA has found that bimonthly OGI monitoring is the best system of emission reduction (BSER) for monitoring equipment leaks at onshore natural gas processing plants for both components “in VOC service” (traditional applicability) and components in GHG service that are not in VOC service. We disagree that annual monitoring of components that are not in VOC service but in GHG service is BSER. The commenter did not provide information showing that EPA’s BSER analysis is incorrect in any aspect or supporting its claim that bimonthly OGI monitoring imposes significant and unnecessary additional cost. In addition, the EPA has also finalized an alternative LDAR program that allows the owner/operator to comply with an EPA Method 21 program like that required for onshore natural gas processing plants in New Source Performance Standards (NSPS) OOOOa and OOOO, which has been implemented at onshore natural gas processing plants subject to these subparts for many years. This alternative allows quarterly monitoring for valves and annual monitoring for connectors. The EPA did not find this long standing LDAR program based on Method 21 as the BSER because it is not as cost effective as OGI, but our modeling indicated that the Method 21 alternative applied to all components with a potential to emit methane or VOC provided equivalent emission reductions as bimonthly OGI. <sup>1</sup>This EPA Method 21 alternative is also like the requirements that Lambda Energy Resources described in their comments.

Regarding DOR leniency in the event GHG components are found leaking and cannot be repaired or replaced without a process unit shutdown, the final NSPS OOOOb and the model rule implementing EG OOOOc allow for the DOR for equipment that cannot be repaired or replaced without a process unit shutdown.

Comment: Commenter (2240-Rose Rock Environmental Services, LLC) suggests that while bimonthly OGI is an excellent method for manually monitoring for leaks, low-cost continuous monitoring solutions provide a more cost-effective means of further reducing emissions by

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<sup>1</sup> See 86 FR 63232, November 15, 2021.



providing immediate detection of leaks down to 3 standard cubic feet per hour (scfh). The commenter encourages EPA to also allow continuous monitoring technology solutions as a BSER for natural gas processing plants to minimize methane emissions.

Commenter (2333-LongPath Technologies, Inc. (LongPath)) suggests that continuous methane emissions monitoring technologies with the ability to provide valid quantification (emission rate) should be allowable to meet the proposed standard.

Response II-12-2: The EPA agrees with the commenters that employing continuous monitoring technology to detect VOC and methane leaks from equipment at onshore natural gas processing plants can be used to achieve emission reductions equivalent to those achieved by bimonthly OGI. The use of a continuous monitoring technology is not directly specified in this final rule because the application of a continuous monitoring network that achieves equivalent emission reduction to bimonthly OGI (BSER) is very site-specific, dependent on the plant layout and prevailing meteorological conditions, to assess proper number and placement of continuous monitors based on the sensitivity of the monitoring sensors. Because a site-specific approach is needed, this final rule provides a pathway for allowing the use of continuous monitoring technology as an alternative on a site-specific basis.

Comment: Commenter (2433-Environmental Defense Fund (EDF) *et al.*) supports EPA's proposal to require bimonthly OGI monitoring in accordance with Appendix K for all pumps, valves, and connectors located within affected process units at onshore natural gas processing plants. The commenter states this is an appropriate BSER for both new and existing processing plants that is cost-effective and can significantly reduce emissions.

Response II-12-3: Comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2180-Pennsylvania Department of Environmental Protection) recommends that for natural gas processing plants, audio, visual, and olfactory (AVO) be conducted monthly, and instrument-based inspections should be conducted quarterly. The commenter states that Pennsylvania has required this inspection frequency since 2013.

Response II-12-4: A combined monitoring of quarterly OGI and monthly AVO was not evaluated as BSER for natural gas processing plants because, unlike well sites and compressor station sites, natural gas processing plants typically are manned and because AVO is not expected to be effective for identifying leaks from all potential methane leak source, such as leaks of treated natural gas. The rule provides AVO requirements based on the fact that some equipment leaks can be identified via AVO methods as part of daily operational duties. For example, pumps in light liquid service must be visually monitored weekly for indications of liquids dripping. Open-ended valves and lines, pumps, valves, and connectors in heavy liquid service, and pressure relief devices in light liquid or heavy liquid service are subject to leak repair anytime there is evidence of a leak by AVO. As discussed in Response II-12-1, the EPA has found that bimonthly OGI monitoring using Appendix K is the BSER for equipment leaks at onshore natural gas processing plants, and the commenter did not provide information showing that EPA's BSER analysis is incorrect in any aspect.

Comment: Commenter (2193-California Air Resources Board) believes the application of LDAR requirements should be uniformly applied to all facilities. The commenter notes that the proposed structure creates different LDAR requirements for every different type of facility, which the commenter believes is likely to result in extreme difficulty with respect to enforcement and compliance due to the different rules for nearly every type of facility, as well as a great deal of regulatory complexity in implementation. The commenter cites to California's Greenhouse Gas Emissions Standards for Crude Oil and Natural Gas Facilities<sup>2</sup> which the commenter states have the same LDAR requirements regardless of the facility type. The commenter believes that amending this portion of the proposed rule to require quarterly EPA Method 21 inspections, or alternatively, bimonthly advanced technology inspections with annual OGI monitoring, regardless of the type of facility, would ensure a streamlined process for states to implement and enforce in their plans.

Response II-12-5: The EPA is required by CAA section 111 to establish the best system of emission reduction (BSER) for each type of affected facility. The EPA has found that bimonthly OGI monitoring using Appendix K is BSER for monitoring VOC and methane leaks from equipment at onshore natural gas processing plants. EPA has also finalized an alternative LDAR program that allows the owner/operator to comply with an EPA Method 21 program like that required in NSPS OOOOa. EPA has found that BSER at single wellhead only sites and small well sites is quarterly AVO, BSER at multi-wellhead only sites is quarterly AVO and semiannual monitoring using OGI, BSER at well sites with major production and processing equipment and centralized production facilities is bimonthly AVO and quarterly monitoring using OGI, and BSER at compressor stations is monthly AVO and quarterly monitoring using OGI. BSER at well sites and compressor station sites in Alaska North Slope was determined to be annual monitoring using OGI. The commenter did not provide information that EPA's BSER analysis is incorrect in any aspect.

### ***12.1.2 Use of OGI vs. EPA Method 21***

Comment: Commenter (2214-BlueCrest Alaska Operating, LLC) requests that EPA allow EPA Method 21 as an alternative to OGI in all instances, as EPA Method 21 can be conducted anytime and allows prompt monitoring and repair, whereas OGI requires advanced scheduling with a contractor.

Response II-12-6: EPA has finalized an alternative LDAR program that allows the owner/operator to comply with an EPA Method 21 program like that required in New Source Performance Standards (NSPS) OOOOa.

Comment: Commenter (2362-Environmental Integrity Project (EIP) *et al.*) states that EPA's proposed requirements related to OGI are arbitrary and capricious and do not constitute BSER for several reasons. First, the commenter states that while OGI can indeed be a useful way to respond to large leaks more rapidly, EPA has not adequately or rationally explained - or explained at all - why it is not requiring sources to also use EPA Method 21 in tandem with OGI. Nor, according to the commenter, has the agency rationally explained, or explained at all, why it would be more cost-effective, in terms of the dollars spent per ton of volatile organic compounds

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<sup>2</sup> See California Code of Regulations, Title 17, Sections 95665-95677.

(VOC) and methane emissions reduced, to eliminate the requirement to conduct full LDAR surveys that identify leaks at or above 500 parts per million (ppm) in return for OGI surveys that are limited to finding leaks that exceed 100,000 ppm, according to the commenter. In the proposed rule, the commenter states that EPA recognizes that LDAR can detect leaks at 500 ppm and although the proposed rule requires OGI equipment to be capable of imaging gas at a concentration of 10,000 ppm, EPA elsewhere recognizes that OGI cannot reliably detect leaks smaller than 100,000 ppm.<sup>3</sup> Thus, by eliminating any requirement to use EPA Method 21, the commenter states that EPA's proposal allows oil and gas sources to ignore leaks that range from 500 to 100,000 ppm. The commenter believes that requiring OGI in combination with regular Method 21 monitoring would detect leaks in the 500 to 100,000 ppm range, would better reduce fugitive emissions of VOCs and methane, and is cost-effective. As part of its cost-effectiveness analysis and rationale, the commenter asserts that the EPA must make available any relevant studies or data that compare the percentage of leaks, and mass and volume of VOCs and methane released during such leaks, as detected by OGI versus Method 21.

Second, the commenter (2362-EIP *et al.*) states, as noted above, while the proposed rule requires OGI equipment to detect leaks at 10,000 ppm, EPA elsewhere suggests that OGI cannot reliably detect leaks smaller than 100,000 ppm. The commenter asserts that EPA must resolve and rationally explain this conflict in the record. If EPA maintains that OGI can detect leaks below 100,000 ppm, they state that the Agency must provide evidence that this is the case.

Response II-12-7: The EPA has found that bimonthly OGI monitoring conducted according to Appendix K is the BSER for equipment leaks at onshore natural gas processing plants and that it achieves equivalent emission reduction to the "quarterly" EPA Method 21 historically required for natural gas plants as provided in NSPS OOOO/OOOOa without the need for an annual EPA Method 21 monitoring requirement. We attribute this to two factors: more effective OGI monitoring based on the requirements of Appendix K and the ability of OGI to readily detect methane and other light hydrocarbons in process streams at natural gas processing sites. These two factors allow a work practice of bimonthly OGI surveys to achieve equivalent emissions reductions to the current EPA Method 21-based work practice in NSPS OOOOa. We assessed including an annual EPA Method 21 requirement in addition to bimonthly OGI surveys but determined that the additional emission reductions achieved by the annual EPA Method 21 monitoring was not cost effective for natural gas plants. Therefore, we did not include an annual EPA Method 21 monitoring as part of the BSER.

We also note that the commenter is misinterpreting the model inputs when they suggest that OGI does not detect leaks below a concentration of 100,000 ppmv. That is not the case. The model assumption that the commenter is referencing is related to the probability of detection - we assumed OGI would detect 100% of leaks with a concentration above a 100,000 ppmv EPA Method 21 concentration; that does not mean that an OGI camera will not detect leaks below 100,000 ppmv. The OGI camera required for surveys of fugitive emissions components in NSPS OOOOa requires a demonstration that it can image a gas mixture of propane and methane with a concentration of 10,000 ppmv. As EPA stated in the preamble to the final rule for NSPS OOOOa, "Available data show that OGI can detect fugitive emissions at a concentration of at

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<sup>3</sup> See EPA-HQ-OAR-2021-0317-0166, Attachment 6 [Excel sheet] at "Introduction" Tab (assuming an OGI concentration sensitivity of 100,000 ppm).

least 10,000 ppm when restricting its use during certain environmental conditions such as high wind speeds. Due to the dynamic nature for the OGI detection capabilities, OGI may also image emissions at a lower concentration when environmental conditions are ideal.”<sup>4</sup> Studies performed in support of the final TSD for Appendix K show that in the right conditions, a cooled, midwave infrared camera can easily see leaks at a concentration below 10,000 ppmv.

The primary factor used to determine OGI detection was the projected mass emission rate of the leak, not the concentration of the leak. It is possible to have high emission rate leaks at both low and high concentrations. Across a large number of Monte Carlo simulations where EPA Method 21 concentration leaks were randomly assigned a mass emission rate consistent with EPA correlation equations<sup>5</sup> and the variability therein, we determined that bimonthly OGI conducted following methods in Appendix K is BSER and achieves equivalent emission reductions as “quarterly” Method 21 included in NSPS OOOOa at natural gas plants without an annual Method 21 monitoring survey.

Comment: Commenter (2362-EIP *et al.*) believes that EPA should require oil and gas sources to keep records of all OGI images and not just a subset of those images. The commenter notes, for example, if EPA is allowing sources to retain only those images that capture leaks as determined by the owner or operator, this would leave EPA and state agencies with no independent ability to assess whether sources are accurately interpreting OGI data. The commenter states that relying on independent contractors for such an assessment will not suffice.

Response II-12-8: EPA disagrees with the commenter. EPA determined that bi-monthly OGI monitoring in accordance with Appendix K is the BSER for equipment leaks at on-shore natural gas processing plants. At these facilities, EPA expects that the effectiveness of the OGI program will be assessed through reviewing facility reports and EPA inspections. Additionally, for sites conducting OGI surveys with Appendix K, EPA and state agencies will be able to review training records, semiannual audits, and daily quality assurance videos for OGI camera operators to assess the ability of an OGI camera operator, as well as facility monitoring plans and records of OGI surveys. These records include information on the meteorological conditions at the site and the length of time surveying was conducted. Reviewing all of this information together will provide EPA and state agencies with information necessary to assess the quality of the OGI survey.

EPA notes that facilities utilizing OGI for leak detection under the alternative work practices at 40 CFR 60.18 and 63.11 must continue to keep video records of the leak survey results, including a time and date stamp for each monitoring event. Whether Appendix K and its recordkeeping requirements is BSER for other industry sectors and should be incorporated into other subparts will be considered in rulemaking for the subparts specifically applicable to those sectors.

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<sup>4</sup> 81 FR 35856-35857 (June 3, 2016).

<sup>5</sup> Protocol for Equipment Leak Emission Estimates. November 1995. EPA-453/R-95-017. Available here: [https://www.epa.gov/sites/default/files/2020-09/documents/protocol\\_for\\_equipment\\_leak\\_emission\\_estimates.pdf](https://www.epa.gov/sites/default/files/2020-09/documents/protocol_for_equipment_leak_emission_estimates.pdf).

### 12.1.3 Use of Appendix K

Comment: Commenter (2248-North Dakota Petroleum Council (NDPC)) believes that the OGI camera is an effective tool for finding leaks. In many ways superior to EPA Method 21; however, the commenter notes that Appendix K as written, will discourage use of OGI in the natural gas processing sector.

Response II-12-9: Regarding OGI, this comment is a supportive comment on an aspect of the November 2021 Proposal that has remained unchanged in the final rule; as such, no response is required.

Regarding Appendix K, see responses to relevant comments in this chapter, as well as Volume I, Chapters 15 and 22, and Volume II, Chapter 22.

Comment: Commenter (2196-Private Citizen) states that if Appendix K is finalized as proposed, the current trend to use the alternative work practice (AWP) at gas plants (which has been allowed for years) will revert back to the use Method 21. As written, the commenter is concerned there are too many compliance traps due to the recordkeeping burden. The commenter believes the protocol and the time spent on response factors etc., is designed with chemical species other than light alkanes in mind. The commenter provides a sample hydrocarbon analysis of field gas and sales gas and states that due to the consistency of feed (*i.e.*, field gas) to a natural gas processing plant being essentially 96-98 percent methane and ethane, requiring the use of Appendix K to establish a program to use OGI for the suite of light hydrocarbons (which the commenter states has been established is valid using the methods in 40 CFR 60.5397b) is an unnecessary burden on the industry. The commenter recommends that natural gas facilities be allowed to use the OGI camera as specified 40 CFR 60.5397b or Appendix K. The commenter provides the following recommended changes to the regulatory text at *40 CFR 60.5400b(b)* [introductory text] (suggested additions are underlined):

(b) *Monitoring surveys.* You must monitor for leaks using optical gas imaging in accordance with appendix K of this subpart or as specified in §60.5397b, unless otherwise specified in paragraphs (c) or (d) of this section. [...]

The commenter (2196-Private Citizen) states that Appendix K becomes relevant when other industries with chemicals species that fall outside of the well-established light hydrocarbon range (C<sub>5</sub> and less), where there is about a decade of data showing that the OGI camera adequately images these hydrocarbons. These other industries, such as refining and synthetic organic chemical manufacturing industry (SOCMI), can incorporate Appendix K by reference, states the commenter.

Response II-12-10: We disagree with the commenter that the compliance provisions in the final Appendix K are too burdensome and will force facilities to revert back to using EPA Method 21. The commenter did not specify which recordkeeping provisions are problematic from a compliance standpoint, The EPA carefully balanced recordkeeping burden with the minimum records needed to ensure that the requirements of Appendix K are followed. We also disagree that we should allow the OGI method for fugitive emission components as specified in

§60.5397b for gas plants. The detection limit requirements in Appendix K are lower than those specified in §60.5397b. The lower detection limits in Appendix K were critical in our determination that OGI provided equivalent emission reductions to EPA Method 21 for gas processing plants.

Regarding Appendix K, see responses to relevant comments in this chapter, as well as Volume I, Chapters 15 and 22, and Volume II, Chapter 22.

Comment: Commenter (2286-Colorado Department of Public Health and Environment (CDPHE)) agrees that LDAR is a necessary program to reduce emissions at natural gas processing plants, but the commenter is concerned about the potential shortage of expertise to conduct necessary inspections for Colorado’s approximately 60 natural gas processing gas plants, due to the level of credentials and experience required to be an Appendix K LDAR technician. The commenter notes the state has long required the owners or operators of natural gas processing plants located in Colorado’s ozone nonattainment area to comply with LDAR requirements, beginning in 2003 with EPA’s LDAR program in NSPS KKK, and currently requires the owners or operators of natural gas processing plants to comply with the LDAR requirements in EPA’s NSPS OOOO or NSPS OOOOa on a state-wide basis. According to the commenter, these facilities may have to revise their LDAR programs to comply with EPA’s presumptive standards for natural gas processing plants within 36 months after the specified state plan submittal date. Should there be a shortage of credentialed Appendix K technicians, the commenter is concerned that Colorado’s gas plants may be unable to complete the initial and ongoing LDAR inspections.

Response II-12-11: See Response II-22-15 and II-22-28 of Volume II, Chapter 22 of this RTC.

Comment: Commenter (2305-Williams Companies, Inc.) appreciates revisions made in response to comments between the November 2021 Proposal and December 2022 Supplemental Proposal. However, the commenter still has concerns as it relates to gas processing plants. Specifically, the commenter recommends:

- Instead of requiring a dwell time of 2 seconds per component at multiple angles, a minimum of 3 seconds per scene would be more appropriate. When looking for fugitive emissions the actual component is not looked at but instead around the component to see movement of “smoke” that indicates an emission.
- The development of the operating envelope is overly complicated and could inadvertently introduce more issues. Instead, daily field checks would be adequate. These field checks would ensure the camera operator is able to identify fugitive emissions and set a maximum viewing distance. These daily field checks would be completed utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys. Field conditions can change throughout the day so any time there are weather changes that could significantly alter the viewing distance (*e.g.*, large temperature changes of 10 degrees or significant wind changes) a new check would be completed and documented to ensure the viewing distance set point is still adequate to identify fugitive emissions.

- Prescriptive breaks should not be required. When a fugitive emissions survey is being completed the camera operator is not looking through the camera lens for periods longer than 1-2 minutes at a time before the camera is put down so the operator can see their surroundings and walk to the next viewing location. Additionally, when a fugitive emission is identified a more prolonged break is completed while the leak record is being made giving the operator many opportunities to rest their eyes.

Response II-12-12: See Responses II-22-30 and II-22-38 of Volume II, Chapter 22 of this RTC, and section XIV.B.1 (Dwell Time) of the preamble to the final rule for a response to these comments.

## 12.2 Equipment Classification

Comment: Commenters (2399-GPA, 2428-American Petroleum Institute (API)) believe that EPA should retain the “in VOC service” requirement and 10 percent VOC by weight threshold, as well as establish a methane threshold, as the current thresholds for VOC and methane are essentially zero. Both commenters suggest a 1 percent threshold for equipment in methane service. Commenter (2399-GPA) explains that gas plants contain many streams, such as acid gas, wastewater, and recycled water, where VOCs and methane are present but so low that they would not be detected by flame ionization detectors (FIDs). The commenter includes data from acid and amine gas samples by way of example. The commenter is concerned, that because the VOC or methane content of these streams are not zero, and presumably have a theoretical potential to emit, owners and operators would waste substantial resources to conduct LDAR monitoring on components that will always result in non-detects. The commenter states that the December 2022 Supplemental Proposal offered no actual data to the contrary. Thus, they contend that the proposed regulatory language would wastefully impose costs and burdens on owners and operators with no potential benefit.

Commenter (2428-API) points out that some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions and would add costs and use personnel resources with minimal, if any, environmental benefit. Examples of such streams, provided by the commenter, include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The commenter states that in existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions, but that in this rulemaking, the agency has not provided sufficient justification for deviating from this longstanding practice.

The commenter (2428-API) questions EPA’s analysis in the November 2021 Proposal, where the commenter states that EPA appears to consider only components in VOC service (defined as 10 percent by VOC by weight or in wet gas service) or in non-VOC service (defined as a component in methane service with at least 10 percent methane that is not also in VOC service). The commenter states that EPA then estimates VOC and methane emissions, reductions and

cost-effectiveness using a limited set of composition ratios,<sup>6</sup> then appears to treat the “potential to emit methane” as equivalent to “in non-VOC service” in evaluating control options. Therefore, the commenter states, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. The commenter reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). To address this the commenter offers the following recommended edits to the definitions in 40 CFR 60.5430b (suggested additions are underlined; suggested deletions are shown in strike-through):

*Equipment*, as used in the standards and requirements of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit in methane or VOC service~~ and any device or system required by those same standards and requirements of this subpart.

In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)

Regarding how to determine when a piece of equipment is not subject to monitoring, the commenter (2428-API) suggests that the language in 40 CFR 60.5400b(a)(2) should also be revised, as appropriate.

Conversely, commenter (2433-EDF *et al.*) supports EPA’s proposal to eliminate the “in VOC service” distinction for purposes of LDAR inspections and instead require bimonthly OGI (in accordance with Appendix K) at all pumps, valves, and connectors located within affected process units at processing plants. The commenter believes that EPA is correct that “a VOC concentration threshold bears no relationship to the LDAR for methane and is therefore not an appropriate threshold for determining whether LDAR for methane applies.” They add that they also believe EPA is correct that “since there would be no threshold for requiring LDAR for methane, any equipment not in VOC service would still be required to conduct LDAR for methane even if not for VOC.”

Response II-12-13: The EPA is not including a VOC or methane threshold in the final rule. See discussion in section XI.L.1 (Potential to emit methane and VOC) of the final rule preamble.

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<sup>6</sup> The commenter (2428-API) refers to Table 10-8 of the Technical Support Document (TSD). See EPA-HQ-OAR-2021-0317-0166.



## 12.3 Overlapping NSPS Applicability

Comment: Commenter (2286-CDPHE) requests that EPA put forth a singular standard for gas plant LDAR to streamline oversight and reduce uncertainty in the various applications of portions of federal rules. The commenter notes that EPA thoroughly discusses in the proposal that some sources may already be subject to similar requirements under EPA's NSPS KKK, NSPS OOOO, or NSPS OOOOa, which may vary in stringency as compared to EPA's proposed standards. The commenter notes that the November 2021 Proposal and the December 2022 Supplemental Proposal identify specific sections of several existing NSPS which oil and gas plants are subject to; namely, the proposal combines select requirements found in NSPSs KKK, VV, VVa, OOOO, and OOOOa. While the commenter appreciates EPA's narrative discussion comparing the older NSPS to the proposed presumptive standards, the commenter requests that EPA include the described more stringent provisions in the proposed presumptive standards directly or by reference, should EPA prefer those requirements continue to be implemented instead of the proposed presumptive standards once finalized.

Response II-12-14: The EPA is finalizing the regulatory structure as proposed. The EPA notes that Method 21 may be used as an alternative to OGI at gas plants, so sources have the option to streamline to one detection methodology should they choose. Regarding the standards for compressors subject to NSPS KKK which will become subject to a state or Federal plan implementing the presumptive standards of EG OOOOc, see the discussion in section IX.C of the preamble to the final rule.

Comment: Commenter (2222-Wisconsin Department of Natural Resources (WI DNR)) states that it would provide significant clarity and consistency to both state regulators and affected sources if NSPS OOOOb and emission guidelines (EG) OOOOc were to incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants. Further, the commenter states that EPA should consider taking this approach for other categories of affected sources that will be covered by the new NSPS and EG as well as the existing NSPS.

Response II-12-15: The EPA evaluated this option and determined that incorporating compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants in NSPS OOOOb or EG OOOOc was unnecessary. The EPA is instead clarifying applicability of requirements in the final rule preamble and NSPS KKK regulatory text. See discussion in section IX.C (How will the final EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa?) of the final rule preamble.

## 12.4 Request for Exemption

Comment: Commenter (2248-NDPC) requests that temporary portable natural gas liquid processing skids ( $\leq 10$  million standard cubic feet per day (MMscfd)) in the oil and natural gas production segment be exempt from requirements applicable to natural gas processing plants in the natural gas processing sector.

Response II-12-16: The EPA cannot tell from the information provided if the commenter means that all temporary/portable units are  $\leq 10$  million standard cubic feet per day (MMscfd) or whether the commenter is asking for two types of exclusions from the definition of natural gas processing plant (i.e., temporary/portable and size). With respect to exemptions for natural gas processing plants which do not have the design capacity to process 10 MMscfd or more of field gas, see the discussion in Response II-12-21. Regarding temporary units, the EPA is not finalizing an exclusion from the definition of natural gas processing plants for temporary/portable units, beyond the exclusion for standalone Joule-Thompson skids which currently exists in the definition of natural gas processing plant in NSPS OOOO and OOOOa and is being finalized for NSPS OOOOb and EG OOOOc. The commenter did not provide any information on why the temporary/portable status is relevant to whether an operation meets the definition of natural gas processing plant. Further, if the exclusion also is tied to a size cutoff, the commenter did not provide a basis for how the size would be (re)determined as the temporary/portable natural gas processing skid is moved from site to site. The EPA therefore is not making the changes suggested by the commenter.

## **12.5 Closed Vent Systems and Equipment Designated as No Identifiable Emissions**

Comment: Commenter (2399-GPA) states that EPA has provided no rationale for either increasing closed vent system monitoring frequencies from the current initial EPA Method 21 monitoring and annual AVO inspections under NSPS VVa or requiring optical gas imaging inspections instead of EPA Method 21 monitoring. The commenter explains that closed vent systems have extremely low leak rates, largely owing to the small number of components and the lack of constantly moving parts, such as valves. The commenter explains that hard piping or duct work will not suffer the type of deterioration, and potential leaks, as moving parts that endure friction. The commenter believes that EPA should either withdraw this proposed requirement or provide some explanation regarding the basis for increasing the monitoring frequency, including a description of what environmental benefit could be expected by more frequent monitoring of equipment that rarely leak.

Response II-12-17: Contrary to the commenter's assertion, the EPA did explain the basis for requiring bimonthly OGI monitoring. Specifically, in section IV.L.1.b. of the December 2022 Supplemental Proposal,<sup>7</sup> The EPA stated "[w]e believe it is most efficient and cost effective to monitor the CVS at the same frequency and according to the same methodology as other equipment in the process unit equipment affected facility," which is bimonthly monitoring. The commenter did not mention, much less provide substantive comment disputing, this rationale.

Comment: Commenter (2433-EDF *et al.*) requests that EPA extend bimonthly OGI monitoring to any equipment or components designated as having no detectable emissions. As bimonthly monitoring will already be required, surveying additional components and equipment will add very little cost, according to the commenter, and is an inexpensive solution for ensuring compliance that will also help operators detect any anomalous sources at the processing plant.

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<sup>7</sup> 87 FR 74807.

Response II-12-18: The EPA is not requiring OGI monitoring for equipment which is designated as having no detectable emissions; instead, the EPA is finalizing a standard of “no identifiable emissions” when using OGI, where a numerical limitation is relevant. See discussion in Section XI.K. of the preamble to the final rule for the rationale for this change.

Regarding extending bimonthly OGI monitoring to equipment or components, which under NSPS OOOOa are designated as “no detectable emissions” (e.g., pressure relief devices (PRDs), open-ended valves and lines, and closed vent systems) the EPA explained in the 2022 Supplemental Proposal<sup>8</sup> that a review of the NSPS KKK record found that the basis for the standards for PRDs was a routine LDAR program, not a “no detectable emissions” standard. Therefore, in the final rule, PRDs must be monitored bimonthly using OGI (or periodic monitoring using Method 21, as an alternative) and repaired. Similarly, EPA discussed in the 2022 Supplemental Proposal that it is not cost effective to require the BSER LDAR program (i.e., bimonthly OGI) for open-ended valves or lines. Finally, for closed vent systems, bimonthly OGI monitoring is finalized with a standard of “no identifiable emissions” as discussed in Section XI.K of the preamble to the final rule.

## 12.6 Leak Repair Timeline

Comment: Commenter (2433-EDF *et al.*) supports the proposed repair timeframe, which would require leaks detected by OGI to be repaired within 5 days of detection and final repairs completed no later than 15 days of detection. The commenters also urge EPA to require repair within 5 days of detection without exception for technical infeasibility.

Response II-12-19: Due to the nature of OGI monitoring (i.e., surveying from a distance), the proper equipment needed for physically reaching a component may not be in place at the time of monitoring and may take longer than 5 days to put in place. Therefore, we believe that a technical infeasibility exemption for the first attempt at repair within 5 days is reasonable, when the repair would require elevating the repair personnel more than 2 meters above a support surface. In all cases, the final NSPS OOOOb requires that final repairs be completed no later than 15 days of detection, unless there is a qualified delay of repair.

## 12.7 Leaking Valve Replacement

Comment: Commenter (2433-EDF *et al.*) urges EPA to require replacement of leaking equipment with low-E valves, despite the agency’s previous determination not to require their use because the agency believes such a replacement is not appropriate for all valve repairs. The commenter points to a recent rulemaking, where Colorado found these options to be similar in cost to non-low-E valves and packing and directed operators to consider them.<sup>9</sup> Some manufacturers claim their low-E packing can reduce emissions of harmful gases by up to 95

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<sup>8</sup> See 87 FR 74807.

<sup>9</sup> See Colorado Air Pollution Control Division, Rebuttal Prehearing Statement, Proposed Revisions to Regulation Numbers 7 and 22 (Dec. 14–17, 2021).

percent versus valves with traditional packing, with minimal cost impacts, according to the commenter.<sup>10</sup>

Response II-12-20: See discussion in section XI.L.2 (Low-E technology for repair) of the preamble to the final rule for EPA's response to this comment.

## **12.8 Regulation Definitions**

### ***12.8.1 Definition of Natural Gas Processing Plant***

Comment: Commenters (2248-NDPC, 2326-American Exploration and Production Council (AXPC)) state that the definition of natural gas processing plant should be amended, to incentivize development of a broader range of potential beneficial uses.

Commenter (2248-NDPC) states that there are technologies that can be used to shrink the volume of wet natural gas that would otherwise be flared, or to process and compress the produced gas to be used as fuel for drill rigs or other nearby sources, but due to confusion about what NSPS standards would be applicable, producers have avoided these technologies. The commenter requests that the EPA clarify the definition of a Natural Gas Processing Plant as follows:

A natural gas processing plant consists of equipment used to separating certain hydrocarbons and fluids from the natural gas to produce "pipeline quality" dry natural gas for the Transmission Sector. The natural gas processing plant is in the Processing Segment. While some processing of natural gas can be accomplished in the production segment, processing equipment with the capacity of less than or equal to 10 MMscfd would not be considered a natural gas processing plant for the purposes of NSPS.

The commenter (2248-NDPC) believes that this definition is consistent with the NSPS OOOOa Technical Support Document (TSD), would clarify the application of any NSPS standards that are different between production, and processing segments, and would allow for more options to create beneficial uses of stranded natural gas.

Commenter (2326-AXPC) states that under the proposed definition, equipment used to put associated gas to beneficial use (as required by EPA's proposed oil well associated gas requirements) would be a natural gas processing plant if the equipment extracts natural gas liquids from field gas. Indeed, one of EPA's enumerated beneficial uses is the production of liquified natural gas, which requires the extraction of natural gas liquids from field gas, according to the commenter. In some regions, the commenter explains, operators utilize small natural gas liquids extraction skids, and EPA has recognized this fact in its exclusion of certain types of equipment from the natural gas processing plant definition. However, to further incentivize the beneficial use of associated gas through use of technologies or processes not explicitly excluded from the definition (e.g., a mobile refrigeration skid) EPA should exclude equipment with a design processing capacity of less than 10 MMscf/day according to the

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<sup>10</sup> Id.

commenter. The commenter suggests the following definition of natural gas processing plant (underlined text indicates new text and struck through text indicates deleted text):

*Natural gas processing plant* means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The following are not a natural gas processing plant: A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid, or any combination of equipment having a design natural gas processing capacity of 10 MMscf per day or less is not a natural gas processing plant.

Response II-12-21: The EPA is not finalizing the suggested changes to the definition of natural gas processing plant. Please see the discussion in Response II-12-16.

However, EPA proposed specific exceptions to the requirements for process unit equipment affected facilities at §60.5402b of NSPS OOOOb and §60.5402c of the model rule in EG OOOOc. Specifically, §§60.5402b(b)(1) and 60.5402c(b)(1) allows for quarterly OGI monitoring (instead of bimonthly OGI monitoring) of pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor and light liquid service, and connectors in gas/vapor service and light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas. Further, §§60.5402b(b)(2) and 60.5402c(b)(2) exempts this same equipment from routine monitoring if complying with the EPA Method 21 alternative standards of §§60.5401b and 60.5401c. There is an historical basis for reduced Method 21 monitoring requirements at these facilities going back to NSPS KKK and they are exempt from certain monitoring requirements as specified in §§60.5401(d) and 60.5401a(d) of NSPS OOOO and OOOOa, respectively. The EPA did not re-analyze the exemption for Method 21 in the 2021 Proposal or the 2022 Supplemental Proposal nor did we analyze it for OGI. The EPA did not intend that there would be an exemption from the standards when using one methodology (i.e., Method 21) versus another (i.e., OGI), in light of the fact that EPA has determined that the Method 21 standards are an equivalent alternative to OGI. Therefore, the EPA is finalizing an exemption from routine monitoring for pumps in light liquid service, PRDs in gas/vapor service, and valves and connectors in gas/vapor or light liquid service at nonfractionating plants that do not have the design capacity to process 10 MMscfd or more of field gas, whether using OGI or Method 21, to maintain consistency as well as to maintain the historical treatment of nonfractionating plants of this size.

### ***12.8.2 Definition of Equipment***

Comment: Commenter (2428-API) states that definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred, because capital expenditure is a definition, not a standard or requirement. The commenter is concerned that this lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. By way of example, the commenter notes that for other regulations, EPA has clarified the scope of equipment considered for the affected facility<sup>11</sup>. For leak detection and

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<sup>11</sup> See U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

repair, the commenter suggests that an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the commenter asserts that the definition of equipment should clearly specify it also applies to capital expenditure. The commenter offers the following recommended edits to definitions in 40 CFR 60.5430b (underlined text indicates new text and struck out text reflects deleted text)<sup>12</sup>:

Equipment, as used in the standards and requirements and for purposes of evaluating capital expenditure in section 60.5365b(f)(1) of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ in methane or VOC service and any device or system required by those same standards and requirements of this subpart.

In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)

In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)

Response II-12-22: The EPA is not making the change regarding the definition of equipment. The EPA disagrees that there is a need to revise the definition of equipment to specify it also applies to capital expenditure when cited at 40 CFR 60.5365b(f)(1). 40 CFR 60.5365b(f) clearly establishes the scope of equipment to which the following paragraphs apply (i.e., the group of all equipment within a process unit) and the proposed definition of equipment specifies that the definition applies to all standards and requirements relative to the process unit affected facility (which includes the modification and capital expenditure provisions). Further, EPA notes that the definition of equipment finalized in NSPS OOOOb and EG OOOOc is consistent with the existing NSPS OOOO and OOOOa “equipment” definitions, which have been used since 2012 and 2016, respectively.

In response to edits recommended related to “in methane service” and “in VOC service”, EPA is not including a VOC or methane threshold in the final rule. See discussion in section XI.L.1 (Potential to emit methane and VOC) of the final rule preamble.

## **12.9 Miscellaneous Other Comments**

Comment: Commenter (2196-Private Citizen) believes there may be a citation error in the text at 40 CFR 60.5400b(h). The commenter notes that there is no (h)(7) as referenced in that paragraph of the proposed regulatory text. The commenter offers the following suggested edits (underlined text indicates new text and struck through text indicates deleted text):

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<sup>12</sup> The commenter (2428-API) also provided comments on defining “in VOC service” and “in methane service” in a prior comment. The edits suggested in this paragraph also include edits suggested to address that prior comment.

40 CFR 60.5400b(h)-

(h) *Repair requirements.* When a leak is detected, you must comply with the requirements of paragraphs (h)(1) through (65) of this section, except as provided in paragraph (h)(76) of this section.

Response II-12-23: EPA has modified the regulatory text accordingly.

Comment: Commenter (2428-API) states that 40 CFR 60.5401c(i)(6)(iii) cites 40 CFR 60.5401c(i)(4)(iii)(A) and (B), however, the commenter states that those citations do not exist. The commenter suggests that perhaps the citation should be 40 CFR 60.5401c(i)(6)(iii)(A) and (B).

Response II-12-24: EPA has modified the regulatory text accordingly.

Comment: Commenter (2222-WI DNR) states that the December 2022 Supplemental Proposal includes a requirement to repair open-ended valves or lines whenever emissions are identified in order to comply with the general duty provisions. However, these requirements are not accompanied by any specific monitoring requirements for open ended valves or lines that would result in identification of emissions.

Response II-12-25: AVO monitoring is required for open-ended valves and lines, but the commenter is correct that the final rule does not specify a frequency. The EPA discussed the rationale for the standards for open-ended valves and lines in the 2022 Supplemental Proposal.<sup>13</sup> The EPA is finalizing, as proposed, that the primary control requirement for open-ended valves and lines is the closure device, which can achieve nearly 100 percent emissions reductions. In the case that there may be a leak past a closure device, which is detected as part of daily operating duties using AVO or required OGI surveys for other equipment, the final rule requires that leaks detected by any method (and at any frequency) must be repaired.

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<sup>13</sup> See 87 FR 74087.

## Chapter 13. Storage Vessels

### 13.1 General Support/Opposition for Proposed Requirements

Comment: Commenters (1611-East Liberty Presbyterian Church, 1620-Evangelical Environmental Network, 1644-Young Evangelicals for Climate Action, 1651-Creation Justice Ministries, 1658-Physicians for Social Responsibility, 2028-Westmoreland Marcellus Citizens' Group (WMCG), 2039-Citizens to Preserve Ligonier Valley, Inc., 2174-Progress Michigan, 2217-Religious Action Center of Reform Judaism (RACRJ), 2236-Physicians for Social Responsibility Pennsylvania, 2352-Environment Texas Research and Policy Center, 2356-Earthworks *et al.*, 2364-CleanEarth4Kids, 2394-Earthworks, 2404-Dakota Resource Council, 2422-Western Leaders Network, 2466-Pennsylvania State Senator Katie Muth, 2502-Rio Grande International Study Center) request that all storage tanks be covered under the rule with no exemptions. The commenters state that these tanks continue to pollute after the drilling process is completed and people have reported illness due to exposure to fumes emitted.

Commenters (2028-WMCG, 2195-Environmental Health Project (EHP), 2212-Union of Concerned Scientists (UCS), 2217-RACRJ, 2303-National Tribal Air Association (NTAA), 2394-Earthworks, 2407-Methane Action *et al.*, 2433-Environmental Defense Fund (EDF) *et al.*, 2462-Private Citizen) suggest that the rule does not go far enough in scope or stringency. Commenter (2462-Private Citizen) requests that EPA expand the rules to include all tanks (*e.g.*, tanks to store outflows with gas emissions) and enhance standards for construction, capture of fugitive emissions, and monitoring. Commenters (2195-EHP, 2212-UCS, 2217-RACRJ) also request that EPA expand the categories of tanks covered by the emissions standards. Commenters (2303-NTAA, 2394-Earthworks, 2433-EDF *et al.*) request that EPA lower the threshold which determines which tanks are covered by the rule. Commenter (2407-Methane Action *et al.*) recommends strengthening standards that address emissions from oil and gas storage tanks by making them applicable to more tanks. The commenter suggests that by lowering the threshold that determines which tanks are covered by the rule, EPA could address the pollution from more tanks, thereby better protecting communities.

Commenter (2394-Earthworks) believes that the proposed rule leaves a significant loophole for storage tank emissions at small wells sites, which must be addressed. The commenter states that these small wells account for over 50 percent of Pennsylvania's oil and gas methane pollution, are decades old (often in neglected or poor condition), but are owned by companies who profit from operation of these small wells – in Pennsylvania, just ten operators generated 60 percent of production<sup>1</sup> from small wells in 2019, each of them earning between \$5 million and \$48 million in revenue, according to the commenter. The commenter explains that at their surveys of produced water storage tanks at smaller well sites in Pennsylvania often are the source of some of the worst emissions<sup>2</sup> and that these tanks often are located not only near homes and schools, but in the middle of backyards and playgrounds. The commenter states that these tanks are designed such that they continuously release benzene and other health hazardous pollutants into

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<sup>1</sup> Earthworks, "Gov Wolf: Despite its claims, oil and gas industry can afford to cut pollution," September 2020, <https://earthworks.org/blog/gov-wolf-despite-its-claims-oil-and-gas-industry-can-afford-to-cut-pollution/>.

<sup>2</sup> YouTube, "Low-producing well storage tank emissions, Forest County, PA (June 2021)," June 2021, <https://www.youtube.com/watch?v=BwX6LTBWijc&list=PL9BS7nDf-8trQ91EHSnuL7Gtzrv9S0be6&index=127>.



the air and the problem with these smaller sized tanks must be taken seriously. The commenter also provided results of fieldwork they conducted in Pennsylvania. Finally, the commenter believes the applicability should include brine tanks.

Response II-13-1: EPA points out several key factors to address the concerns of the commenters. EPA is finalizing the November 2021 Proposal and December 2022 Supplemental Proposals which modified the applicability criteria to remove averaging across storage vessels in the same tank battery. “Tank battery” has been defined to include tanks with common liquid piping, such that more tanks are to be regulated and direct their emissions through a closed vent system to a control device. EPA has revised the criteria for tanks that adopt legally and practicably enforceable emissions limitations, to better assure reductions in emissions are achieved. The final rule, consistent with NSPS OOOO, OOOOa, and the December 2022 supplemental proposal, applies to storage vessels which contain crude oil, condensate, intermediate hydrocarbon liquids, and produced water.

EPA disagrees that the 6 tpy threshold is a loophole. Contrary to commenter’s implication, the proposed OOOOb and OOOOc did not exempt single storage vessels not located at a well site, centralized production facility, compressor station, or a natural gas processing plant, nor does EPA have any such intent. EPA has set the threshold for tanks emitting 6 tpy VOC and 20 tpy methane based on reductions that can be obtained under the BSER analysis which includes the factor of cost effectiveness. Tank batteries which emit less than 6 tons per year (tpy) VOC or 20 tpy methane are not storage vessel affected facilities and do not have to be controlled under the NSPS or EG. EPA cannot discern from the comment what the potential for VOC and methane emissions are for the “small” tanks in referenced by the comment. EPA considered lowering the threshold of applicability for volatile organic compounds (VOC) emissions and contemplated a series of applicability thresholds for methane. EPA chose to retain the 6 tons per year (tpy) threshold for VOC because a lower threshold was not cost effective and chose the 20 tpy threshold for methane for the same reason. The 20 tpy threshold for methane applies to existing sources. See EPA’s cost analysis for tanks cost memo in the TSD to the proposed rule in the docket, EPA-HQ-OAR-2021-0317-0039.

EPA recognizes that some tanks which take legally and practicably enforceable limits to remain below the applicability thresholds, may experience excess emissions episodes for various reasons (e.g., unintended gas carryover or open thief hatch). In those cases, any excess emissions episodes would be addressed through enforcement of the emission limits by the respective permitting or enforcement agency, including EPA. EPA is also finalizing a Super-Emitter Response Program that will address emissions for storage vessel affected facilities that experience a super emitter event.

Comment: Commenters (2199-Rocky Mountain Farmers Union (RFU) *et al.*, 2362-EIP, 2458-MiQ) request an increase in the stringency of controls. Commenter (2458-MiQ) supports the provision to increase combustion efficiency to 98 percent control and to require additional monitoring of the control device. Commenter (2199-RMFU *et al.*) suggests that EPA look to states in the east and west which have strengthened controls regarding leaks from storage tanks.

Commenter (2362-EIP) believes EPA should be aware that the state agencies that regulate oil and gas emissions already require that these combustion devices at tank batteries, gas processing units, compressors and other oil and gas sources achieve a 98 percent DRE. These requirements apply to storage tanks and other units where pre-control VOC emissions are well below 90 tons per year, i.e., where pre-control methane emissions are likely to be less than the 20 tons that EPA has identified as the threshold for the 95 percent DRE standard it proposes for storage tanks. The commenter provides several attachments to their comments, as follows:

- Attachment C (of the commenter's public submission) includes 6 permit applications and other records for six permitted tank batteries in Reeves County, Texas, and each one represents that flares or VCUs will achieve 98 percent DRE (permit representations in Texas are enforceable).
- Attachment D (of the commenter's public submission) identifies condensate or produced water tanks at five West Virginia well pads or compressors. Each of these sources has a potential to emit that is less than 90 tons of VOCs per year. The flares or VCUs at each site are required to destroy 98 percent of the tank vapors.
- Tank batteries and other oil and gas sources in Texas that report VOC emissions from flares or VCUs during malfunctions, maintenance, startup, and shutdown have reported achieving 98 percent DRE for many years. Attachment E (of the commenter's public submission) identifies 45 tank batteries or other oil and gas units that reported VOC or sulfur dioxide emissions from flares with links to the online reports that calculate reported emissions based on a DRE of 98 percent. The table includes more than 2,000 reports between 2002 and 2022.
- Attachment F (of the commenter's public submission) summarizes information from four manufacturers (Zeeco, MRW Technologies, Encore Combustion, and Mission Flares & Combustion) that claim that the flares or VCUs they install will achieve destruction efficiencies of 98 percent or greater and indicate such devices are available to upstream and downstream oil and gas operations. [Attachments included in the Comment Letter File.]

Commenter (2362-EIP) believes that these examples show that 98 percent DRE is BSER and is cost-effective. According to the commenter, the EPA's failure to consider such examples means its requirement for a 95 percent DRE is unlawful, arbitrary, and capricious.

Response II-13-2: The EPA has declined to increase the required control efficiency from 95 percent to 98 percent. See EPA's cost analysis for tanks in docket at EPA-HQ-OAR-2021-0317-0039. EPA considered the same comment in our supplemental proposal. Commenters asserted in comments to our proposal, and again here, that 98 percent destruction efficiency was technically possible, and to our supplemental proposal, included documentation that flares can achieve 98 percent destruction efficiency and in some cases that level of destruction efficiency is enforceable. EPA agrees that flares can achieve 98 percent destruction efficiency, but the commenter fails to address EPA's rationale for not adopting 98 percent as BSER. As explained in our supplemental proposal (see 87 FR 74794) EPA did not find it cost effective to increase destruction efficiency. Specifically, EPA stated, and the commenter did not address that a higher destruction rate would require additional monitoring and commensurate operational costs. EPA determined that a 98 percent destruction efficiency would compel EPA to raise the threshold for

affected facility to 12 tpy VOC and 40 tpy methane for 98 percent to be considered the BSER. EPA further pointed out that raising the threshold for affected facility status would result in more emissions to atmosphere than could be obtained by increasing destruction efficiency by 3 percent.

Comment: Commenter (2383-Baker Hughes) supports EPA's proposed standard that all storage vessel affected facilities reduce methane and VOC emissions by 95 percent and the proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. The commenter also supports EPA's retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane.

Commenter (2258-Marcellus Shale Coalition (MSC)) acknowledges the incorporation of the uncontrolled methane emission rate (14 tpy) for affected facilities as requested in their comments on the November 2021 Proposal and expresses its appreciation for this incorporation.

Response II-13-3: The comment is a supportive comment on an aspect of the December 2022 Supplemental Proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenter (2254-Permian Basin Petroleum Association (PBPA)) states that the application of the VOC and methane thresholds to tank batteries, instead of individual storage tanks will subject a staggering number of facilities to additional regulation. The commenter is concerned that the impact on upstream sources, both in terms of increased storage tank applicability and costs, will increase exponentially. The commenter also is concerned the proposed rule applies uncontrolled potential to emit (PTE) and limits states' ability to consider legally and practicably emissions controls in the PTE calculation, which the commenter says will result in practically every storage tank becoming an affected facility under the proposed NSPS.

Response II-13-4: EPA discusses the rationale for selecting the tank battery framework to determine applicability for storage vessels in section IV.J. of the supplemental proposal. See 87 FR 74800. EPA is finalizing, as proposed, that a storage vessel affected facility is a tank battery with the potential for VOC or methane emissions above 6 tpy or 20 tpy, respectively.

With respect to costs incurred by the industry, the New Source Performance Standard (NSPS) technology review is a statutory mandate that requires EPA to review the NSPS rule every 8 years to determine whether the standards continue to reflect the best system of emission reduction. The timeframe for implementation for existing sources is extended over several years as states adopt plans to implement the EG for existing sources. For further information on the anticipated cost with respect to storage vessels, see EPA's cost analysis for storage vessels at EPA-HQ-OAR-2021-0317-0039. Regarding the use of legally and practicably enforceable limits when determining the potential for VOC and methane emissions from tank batteries, the final rule allows that a source may take into account legally and practicably enforceable limits in such determinations. The final rule also specifies the criteria for legally and practicably enforceable limits. See RTC section 13.2.6. and Section XI.J.1.a of the preamble to the final rule for EPA's

rationale for finalizing the criteria for legally and practicably enforceable emissions limitations specifically for determining storage vessel affected facility/designated facility status under subpart OOOOb/OOOOc.

## 13.2 Applicability

### 13.2.1 Definition of Storage Vessel

Comment: Commenter (2428-American Petroleum Institute (API)) states that a storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must clearly be excluded from the definition of storage vessel. The commenter explains that at some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa, according to the commenter. Now, the commenter states, these tanks present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, the commenter explains, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.<sup>3 4</sup>

The commenter (2428-API) requests that EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows (suggested additions are underlined):

*Storage vessel* means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of 40 CFR 60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than

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<sup>3</sup> CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

<sup>4</sup> The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

180 consecutive days. If you do not keep or are not able to produce records, as required by 60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.

Response II-13-5: EPA disagrees that emergency use tanks should be exempted from the definition of storage vessel. These tanks have the potential to emit large quantities of VOC and methane if uncontrolled. EPA notes, that if the storage vessel is not connected by liquid line to other tanks in the tank battery, then it is not part of a tank battery affected facility and may determine its potential for VOC and methane emissions separately from the tank battery. This determination may take into account legally and practicably enforceable limits, which may include limits on throughput received. Allowing a tank that is connected by liquid line to the remaining tanks to be uncontrolled with respect to air emissions would undermine the standard, because emissions could bypass the control device through the uncontrolled tank. Finally, the commenter did not explain why they cannot be controlled (e.g., safety reasons, technical infeasibility, or cost) and did not explain why the states referenced do not regulate these types of tanks.

### ***13.2.2 Definition of Tank Battery***

Comment: Commenters (2305-Williams Companies, Inc. (Williams), 2399-GPA Midstream Association (GPA)) support the regulatory text defining “tank battery.” Commenter (2399-GPA) states that it is greatly improved from the description EPA included in the November 2021 Proposal preamble (*i.e.*, the term “adjacent” is not included). Commenter (2305-Williams) states that the removal of the terms “adjacent,” “fluids from the same source,” and “vapor transfer” are improvements to the previous definition of “tanks battery.”

Response II-13-6: The comment is a supportive comment on an aspect of the December 2022 supplemental proposal that has remained unchanged in the final rule; as such, no response is required.

Comment: Commenters (2305-Williams, 2399-GPA) do not believe that storage vessels should be required to be manifolded together with piping such that all vapors are shared among the headspace of the storage vessel comprising the tank battery. Commenter (2399-GPA) states that EPA’s proposed requirement to manifold the vapor space for tank batteries, found at 40 CFR

60.5395b(b)(1), unnecessarily dictates how storage vessels are routed to controls. The commenter cites to the December 2022 Supplemental Proposal which states, “that these changes reflect our intent that a group of storage vessels which are manifolded together by liquid line operate as a system and, as such, share the same control device.” 87 Fed. Reg. at 74,800. However, the commenter states that the December 2022 Supplemental Proposal provides no explanation, and cites no record support, for requiring all of the tanks in a tank battery to share the same control device. The commenter goes on to explain that while it is not unusual for all storage vessels in a tank battery to be routed to the same control device, this will not always be possible, such as when vessels store different contents. The commenter states that this means that, under certain circumstances, more than one control device and closed vent system would be required to control storage vessels across a tank battery, especially for storage vessels at existing sites. The commenter is concerned that an owner or operator could find itself unable to comply with conflicting requirements. By way of example, the commenter explains that where steel and fiberglass vessels are forced to share a common vapor space manifold, static buildup and grounding deficiencies will result in a severe safety issue, including the risk of an explosion. Additionally, the commenter describes a scenario where, if storage vessels are not located near each other, it may be better to install two separate control devices. The commenter states that using multiple control devices for storage vessels does not significantly affect emission rates and will result in the same total emissions from the tank battery. The commenter provides the following suggested edits to the regulatory text at 40 CFR 60.5395b(b)(1) (suggested additions are underlined; suggested deletions are shown in strike-through):

(b) Control requirements.

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you all storage vessels within the tank battery must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iii)~~ of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;~~

(iii) The tank battery must be equipped with a closed vent system that meets the requirements of §60.5411b(a) and (c); and

~~(iii)~~ The vapors collected in paragraphs (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

Commenter (2305-Williams) also recommends that EPA delete 40 CFR 60.5395b(b)(1)(ii). The commenter states that storage vessels should not be required to be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels comprising

the tank battery, as is supported by EPA removing “vapor transfer” from its previous definition of “tank battery” so that tank batteries are now defined as a single storage vessel or storage vessels that are manifolded together by liquid transfer only. The commenter believes that EPA’s current closed vent system requirements in 40 CFR 60.5411(b) and control device requirements in 40 CFR 60.5412(b) sufficiently assure proper conveyance and control of storage vessel VOC and methane emissions.

Response II-13-7: EPA agrees with the commenter that it is not necessary to specify that the vapor spaces of the tanks within a tank battery be manifolded for control purposes, because the control criteria of a cover, closed vent system, and control device provide sufficient regulatory certainty that each tank in a storage vessel affected facility must be controlled to 95 percent.

On the issue of whether all tanks should be routed to a single control device, EPA does not interpret “a control device” as “a single control device” for the purpose of controlling a tank battery. By maintaining the text as “a control device” an operator can use redundant or multiple control devices within a single tank battery and still meet the requirements of the standard, because the collection of tanks in a tank battery manifolded by liquid line is an affected facility (where the potential for VOC and methane emissions is met) and each tank in the storage vessel affected facility must be controlled to 95 percent, when the battery as a whole must be controlled to 95 percent.

Comment: Commenters (2428-API, 2483-Interstate Natural Gas Association of America (INGAA)) recommend that the definition of tank battery be clarified with respect to the clause that the tanks are manifolded for liquid transfer. Commenter (2438-INGAA) is concerned of an extreme interpretation where two tanks that are very distant are connected via a pipe and be considered manifolded for liquid transfer. The commenter provides three suggested edits to the regulatory test at 40 CFR 60.5430b and 60.5425c:

**Proposed Regulatory Text** (suggested additions are underlined):

*Tank battery* means a group of all adjacent storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

**Alternative Proposed Regulatory Text** (suggested additions are underlined):

*Tank battery* means a group of all storage vessels located at a well site, central production facility, compressor station, or natural gas processing plant that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if only one storage vessel is present.

**Alternative Proposed Regulatory Text** (suggested additions are underlined):

*Tank battery* means a group of all storage vessels that are manifolded together for liquid transfer, where the liquid free flows between the vessels without assistance from an

external source of energy. A tank battery may consist of a single storage vessel if only one storage vessel is present.

Commenter (2428-API) supports EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offers a clarification regarding its location as follows (suggested additions are underlined):

*Tank battery* means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.

The commenter (2428-API) states that this clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). The commenter explains that these storage vessels typically have low throughput and methane and VOC emissions. Because EPA does not describe how to determine potential to emit (PTE) for tank batteries at locations other than a well site, centralized production facility, compressor station, or natural gas processing plant in 40 CFR 60.5365b(e)(2)(ii) and 60.5365b(e)(2)(iii), the commenter believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

Response II-13-8: Contrary to commenter's belief, the proposed OOOOb and OOOOc did not exempt single storage vessels not located at a well site, centralized production facility, compressor station, or a natural gas processing plant, nor does EPA have any such intent. The commenter points out that storage vessels not located at a well site, centralized production facility, compressor station, or natural gas processing plant typically have low throughput, methane, and VOC emissions. The EPA acknowledges that such single storage vessel may have emissions below the rule's applicability thresholds and therefore not subject to the standards; however, OOOOb and OOOOc apply to those above the threshold(s).

In the commenters' example that a tank could be part of a battery, at distance to the other tanks in the battery, EPA has removed the requirement for manifolding vapor spaces for all tanks in a battery, thereby simplifying compliance in such cases. Tanks manifolded together for liquid transfer and which are storage vessel affected facilities are no longer required to have their vapor spaces manifolded together under the control criteria. This means such a storage vessel, in the commenters example, could be controlled at the distant tank battery of which it is a part, without the need to manifold the vapor space to the other storage vessels in the battery. Therefore, tanks in a tank battery need not be adjacent to each other. The EPA also notes that in the 2022 Supplemental Proposal, it declined to use the term "adjacent" in the definition of tank battery in response to comment on the 2021 proposal. EPA expressed its agreement with commenters to the November 2021 proposal that this term was not needed. See 87 FR 74800.

### ***13.2.3 Definition of Centralized Production Facility***

Comment: Commenters (2399-GPA, 2428-API) believe that the definition of "compressor station," as proposed at 40 CFR 60.5430b, must be clarified with respect to the storage vessel



applicability provisions. Commenter (2399-GPA) believes EPA should revise the definition of “centralized production facility,” because it does not clearly exclude compressor stations that are not part of producing operations. The commenter suggests that the last sentence of the definition be revised as follows (suggested additions are underlined):

A centralized production facility is located upstream of the compressor station, the natural gas processing plant, or the crude oil pipeline breakout station and is a part of producing operations.

The commenter (2399-GPA) is concerned that the proposed definition does not clearly distinguish between a compressor station, which will have associated storage vessels, and a centralized production facility which may have associated compression. The commenter explains that storage vessels located at compressor stations would provide a function similar to a centralized production facility, but they are not “part of producing operations” and without the proposed revision provided above, there would be significant confusion as to how applicability determinations would be performed for storage vessels and which leak detection and repair (LDAR) monitoring program would apply. Further, the commenter suggests that the definition exclude independent centralized production facilities that are not part of producing operations, such as where the centralized production facility is owned by a midstream company separately from production assets. The commenter explains that where a centralized production facility is owned and operated by a midstream company, that company cannot know whether a well site added equipment or fractured a well because there is no obligation for the production company to inform downstream processing companies. The commenter states that EPA should clarify that a centralized production facility that is not part of producing operations is not included in the definition.

Commenter (2428-API) explains that with the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The commenter believes that EPA makes this distinction clearly for how to consider the fugitive emission monitoring, by referencing 40 CFR 60.5397b in the definition of compressor station. By way of example, the commenter examines the scenario of a reciprocating compressor at an oil processing facility. The commenter states that the facility would be a “*tank battery at a well site or centralized production facility*” under 40 CFR 60.5365b(e)(2)(ii) and yet also a “*tank battery located at a compressor station*” as used in 40 CFR 60.5365b(e)(2)(iii). The commenter requests that EPA also clarify the storage vessel requirements in a similar way by the referencing of 40 CFR 60.5365b(e) in the definition of compressor station as follows (suggested additions are underlined):

*Compressor station means* any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.

Response II-13-9: EPA agrees with the commenters additional clarity is needed to better distinguish centralized production facilities from compressor stations. Although we think either suggestion may work, we think modifying the definition of compressor station is sufficient. As such the last sentence of the definition will read as follows:

The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.

#### ***13.2.4 Emissions Threshold for Tank Battery Applicability - General***

Comment: Commenters (2296-New Mexico Environment Department (NMED), 2410-California Office of the Attorney General (CA AG) *et al.*) recommend that the applicability threshold be set lower. Commenter (2296-NMED) explains that their state's applicability thresholds for new and existing storage vessels are lower than what EPA is currently proposing in NSPS OOOOb and EG OOOOc. The commenter notes that NMED's Part 50 requires controls for new storage vessels with a PTE  $\geq 2$  tpy of VOC, existing storage vessels in multi-tank batteries with a PTE  $\geq 3$  tpy of VOC, and existing storage vessels in single tank batteries with a PTE  $\geq 4$  tpy of VOC, according to the commenter. Commenter (2410-CA AG *et al.*) requests that for existing storage vessels, EPA consider lowering the applicable threshold. By way of example, the commenter states that Colorado requires the control of all new and existing storage tanks emitting 2 tpy of VOC or more;<sup>5</sup> Pennsylvania requires controls if VOC emissions exceed 2.7 tpy; and New Mexico has adopted a threshold of 2 tpy of VOC for new tanks, 3 tpy of VOC for existing tanks in multi-tank batteries, and 4 tpy for existing tanks in single tank batteries.<sup>6</sup>

Commenter (2180-Pennsylvania Department of Environmental Protection (PADEP)) recommends that the VOC emissions threshold should be 2.7 tpy and notes that they have required 95 percent control of VOC emissions from storage vessels since 2013.

Response II-13-10: EPA discussed the results of the analysis which was used to establish emissions thresholds for storage vessel applicability in section XII.B.1.e of the November 2021 Proposal and used this same analysis in the December 2022 Supplemental Proposal. The EPA evaluated lower emissions thresholds, including 3 tpy from a tank battery, and as discussed in the same section of the November 2021 Proposal was determined not to be cost effective. EPA also notes that Section 111(d), which requires regulation of existing sources, excludes from such regulation pollutants regulated under CAA section 108(a) (*i.e.*, criteria pollutants such as ground-level ozone and particulate matter, and their precursors, like VOC); therefore none of the VOC limits suggested by the commenters are germane to OOOOc, which contains presumptive standards for reducing methane emissions only. Finally, the commenters did not identify flaws with EPA's analysis and EPA is finalizing the emissions thresholds for storage vessel applicability as proposed.

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<sup>5</sup> 5 Colo. Code Regs. § 1001-9:D.II.C.1.c.

<sup>6</sup> New Mexico Administrative Code 20.2.50, at 20.2.50.123(A), available at <https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2022/07/Oil-and-Gas-SectorOzone-Precursor-Pollutants-Final-rule-20.2.50-NMAC-06Jul22.pdf>.

Comment: Commenter (2356-Earthworks *et al.*) requests that EPA expand the threshold for storage tanks. The commenter states that the December 2022 Supplemental Proposal did not expand the applicability threshold for storage vessels, which are prevalent throughout communities impacted by oil and gas development. They suggest that EPA strengthen the standards to address emissions from storage tanks by making the standards applicable to more tanks.

Response II-13-11: See response II-13-10.

Comment: Commenter (2305-Williams) believes that the proposed emissions threshold of 20 tpy methane is too low and lacks justification. The commenter suggests that EPA review methane emissions for other emissions sources at oil and natural gas facilities and establish a more reasonable emissions threshold and corresponding emission standard for storage vessels. For comparison, the commenter provides the following currently permissible methane emissions in California:

- 80 tpy for a 4-throw reciprocating compressor's rod packing emissions<sup>7</sup>
- 60 tpy for a wet seal centrifugal compressor's degassing vent emissions<sup>8</sup>

For added context, the commenter also provides that the methane emissions from a dry seal centrifugal compressor with a leak rate of 3 scfm/primary seal is 60 tpy, assuming continuous operation and 90 mol percent methane gas composition.

Response II-13-12: EPA disagrees that methane emissions for other sources at oil and gas facilities are relevant to the analysis of cost-effective control of storage vessels. EPA set the threshold for methane control for storage vessels corresponding to the anticipated representative emissions of VOC and methane together, because the current VOC threshold was found to be cost effective. Since the controls used to control VOC are the same controls for methane, it was reasonable for EPA to analyze and select a threshold value for VOC that corresponds to a representative methane level. See the EPA memo describing the BSER analysis [Docket Item No. EPA-HQ-OAR-2021-0317-0039, Attachment 21; based on worst-case ratio of VOC to methane; see "Oil" tab, row 33, data for "Sample Tank No. 52"] and how EPA selected the methane level of 20 tpy as representing the most likely threshold corresponding to 6 tpy VOC.

Comment: Commenter (2168-Indiana Oil and Gas Association) notes that Table 2 of the December 2022 Supplemental Proposal does not provide best system of emission reduction (BSER) for tanks with a PTE of less than 6 tpy and inquires whether those tanks still are not regulated under the proposed rule.

Response II-13-13: In the 2021 proposal, the EPA described its BSER analysis for tank batteries, in which the EPA evaluated routing emissions to a VRU and combustion control device and at different potential emission levels (3 tpy and 6 tpy VOC and 1.3 tpy, 5.3 tpy, 20 tpy, and 50 tpy

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<sup>7</sup> Based on California Air Resources Board's 2 scfm/throw emissions limit, 8760 hours per year operation, and 90 mol percent methane gas composition).

<sup>8</sup> Based on California Air Resources Board's 3 scfm/wet seal emissions limit, 8760 hours per year operation, and 90 mol percent methane gas composition.

methane from a tank battery) (86 FR 63199). The EPA did not find the costs of these control options to be reasonable at the lower thresholds considered. The EPA did not identify any other control options for tank batteries, nor did the commenter suggest any other control for EPA to consider as the BSER for tank batteries with potential VOC and methane emissions below 6 tpy and 20 tpy respectively. Therefore, there is no BSER for tank batteries with potential emissions below these applicability thresholds.

Comment: Commenters (2254-PBPA, 2305-Williams) do not agree with EPA's proposal that when a storage vessel affected facility reduces its emissions below the applicable threshold, it remains an affected facility. The commenter (2254-PBPA) points out this "once in, always in" policy requires facilities to meet regulatory obligations when actual emissions are below the regulatory trigger. The commenter believes that such a policy directly disincentivizes operators from reducing emissions and is unwarranted. The commenter points out that EPA previously had a similar policy for its National Emission Standard for Hazardous Air Pollutants (NESHAPs) but revoked this policy in 2020, in part, based on its study of emission impacts from 34 different facilities. The commenter summarizes that EPA concluded that of the 34 facilities that were reclassified from major sources to area sources, emissions from all facilities either remained the same or were reduced.

Commenter (2305-Williams) reports that natural gas gathering rates and associated condensate production rates in maturing fields can and do decrease as production rates decrease over time. The commenter believes a compressor station operator should be allowed to re-evaluate these changing throughput conditions and potential emissions. The commenter suggests that if the new throughput conditions lead to maximum potential emissions estimates that do not exceed 6 tpy VOC (or the annual methane emissions limit), then the affected storage vessel status should no longer apply.

Response II-13-14: See 78 FR 58415 at 58430, where the EPA explained our position on the need for storage vessels that have experienced a decline in emissions to remain affected facilities. In that notice EPA stated "In the context of once in always in, the EPA has not extended this policy by providing that storage vessel affected facilities that subsequently reduce PTE to below 6 tpy remain affected facilities. The EPA historically has never let facilities in and out of affected facility status and is consistent in subpart OOOO. Having storage vessels remain affected facilities when emissions decline allows regulatory agencies to track emissions of these storage vessels and to monitor compliance if they increase."

### ***13.2.5 Emissions Threshold for Tank Battery Applicability – Methane Permits***

Comment: Commenters (2202-TXOGA, 2428-API, 2483-INGAA) are concerned about basing applicability on methane emissions. Commenters (2202-TXOGA, 2221-Texas Pipeline Association (TPA), 2227-Western Energy Alliance (WEA), 2428-API) also are concerned with the timing of issuing state permits. Commenter (2483-INGAA) states that it is problematic because many permitting programs do not include provisions for methane emissions, and/or the related methane emissions in the transmission and storage segment are below *de minimis* levels in state minor source permit programs. The commenter describes where members have experienced instances in which the member requested from a state permitting authority a permit

limit for methane, and the permitting authority would not issue a permit because the emissions or emission levels were not covered in the state permitting program. Therefore, the commenter recommends retaining the 6 tpy VOC basis for storage vessel/tank battery applicability.

Commenter (2202-TXOGA) recommends that EPA recognize permit limits set for VOC as a surrogate for methane-specific limits. The commenter explains that the Texas Commission on Environmental Quality (TCEQ) does not set and issue to individual sources permit limits specifically for methane<sup>9</sup>. Further, the commenter states, EPA has always recognized that VOC limits also limit volatile organic hazardous air pollutants (VOHAP), and as the Clean Air Act (CAA) section 112 program was being developed, states and sources relied on VOC limits as effective ways to create synthetic minor sources for purposes of Title V where VOHAP were the only HAP emitted. The commenter believes the same result applies with the oil and gas rule under CAA section 111.

Further, commenter (2202-TXOGA) states that they have serious concerns regarding the new definition of “storage vessel affected facility,” given the interrelationship between the new definition and EPA’s earlier proposal to adopt a new definition of “legally and practicably enforceable.”<sup>10</sup> The commenter states that EPA’s proposal to define a “storage vessel affected facility” as a “tank battery” which has the “potential for methane emissions equal to or greater than 20 tpy” is very problematic. The commenter explains that some of their larger members have many hundreds, and in some cases over a thousand tank batteries with VOC limits in place, limits that they spent considerable effort obtaining through minor New Source Review (NSR) permit processes. The commenter believes that EPA is aware that obtaining permit limits in most states requires preparation and submittal of a permit application, review by the state permitting authority, preparation of a draft permit, publication for a 30-day notice and comment period, review of any comments submitted, and finalization of the permit. For Title V facilities, the commenter explains that these terms then needed to be incorporated into the Title V operating permit, which can involve a separate permit amendment process, depending on the state’s regulations. The commenter states that the proposal to require separate methane permit limits, will lead to requiring that same process to be repeated, and even if it turns out that for some of these sources, the VOC limit is effective to limit methane emissions below 20 tpy for the battery, the evaluation by the source and likely confirmation process with the permitting authority will be resource and time consuming. The commenter is concerned that the logistical and administrative burdens have not been adequately considered by the Agency. The commenter states that the December 2022 Supplemental Proposal lacks an adequate analysis of these burdens, which is essential to determining if a transition program is needed. By way of example, the commenter reminds EPA of problems that were confronted as sources sought to obtain minor NSR permits to avoid Title V or so-called federally enforceable state operating (FESOP) permits to obtain PTE limits to be classified as area sources under CAA section 112. The commenter stated that in the 1990s, EPA issued a policy establishing transition rules recognizing that states could not possibly issue the permits needed to create minor Title V sources and section 112 area sources,

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<sup>9</sup> Texas does have under its “permit by rule” program provisions that establish a facility-wide VOC limit of 25 tpy for those sources in the oil and gas industry that choose to opt in to that program.

<sup>10</sup> TxOGA provided comments on “legally and practicably enforceable” in their January 2022 comments in response to the November 2021 proposal. TxOGA did not provide new comments on “legally and practicably enforceable” in response to the December 2022 proposal.

allowing for reliance on actual emissions while permits were processed.<sup>11</sup> This policy was initially set to expire after two years, but the Agency ended up extending it so that it lasted over five years.

The commenter (2202-TXOGA) states that accordingly, one effect of this shift will be to necessitate tank-by-tank and battery-by-battery PTE calculations for methane for these many hundreds of potentially affected facilities. For companies in this situation, the commenter states that this will be a monumental undertaking that, as a practical matter, will take an extraordinary amount of time and that there is no question that transition rules will be essential. The commenter urges the Agency to establish common sense transition rules for any new requirements (1) for legally and practicably enforceability and (2) to phase in the methane 20 tpy applicability limit. The commenter believes that EPA has the ability to place these transition provisions directly into the regulations to provide regulatory certainty to companies and to avoid drastically overburdening state agencies, which are already behind in processing Title V renewals. In particular, the commenter states, EPA should provide that 6 tpy VOC permit limits will (1) be deemed to satisfy any new legal and practical enforceability requirements and (2) be deemed an acceptable surrogate for the 20 tpy methane limit. The commenter states that EPA should provide the revisions be conducted either during the next Title V renewal for the source (provided such renewal is at least one year after rule issuance) or at the next significant permit modification under Title V. For non-Title V sources, the commenter recommends that the transition rules should provide a five-year period to allow sources to obtain necessary permits, recognizing that overburdened states will typically allocate resources to major sources first. This commenter believes that this transition period recommendation makes sense for several reasons:

- First, the VOC limit has been acting as a surrogate limit on methane already.
- Second, many of these tanks qualifying for the less than 6 tpy cut point have vapor recovery units (VRUs) or flares ensuring emissions below the 6 tpy VOC and 20 tpy methane cut points.
- Third, forcing an enormous effort on permitting authorities to create new limits meeting these two new requirements (without emission reduction benefits) is simply an unwise use of resources by the both the regulated industry and permitting authorities.

Commenter (2428-API) states that few existing sources have express emissions limitations for methane or greenhouse gases (GHGs), yet, EPA has proposed a 20 tpy methane applicability trigger for the NSPS OOOOb and EG OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger). As a result, the commenter believes that many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The commenter believes the use of surrogates in establishing effective PTE limits is a cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

Commenter (2428-API) notes that for permitting, methane is typically regulated as a GHG for major sources under the Prevention of Significant Deterioration (PSD) program. The commenter

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<sup>11</sup> EPA, Options for Limiting the Potential to Emit of a Stationary Source Under Section 112 and Title V of the Clean Air Act, Memorandum from John S. Seitz, Office of Air Quality Planning and Standards, and Robert I. Van Heuvelen, Office of Regulatory Enforcement, to Regional Air Directors (Jan. 25, 1995).

is concerned that states may not be able to permit a methane limit under their minor NSR programs. As such, the commenter believes that EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach the commenter recommends is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability, warns the commenter.

Another issue the commenter (2428-API) points out is the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. According to the commenter, one member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time, the commenter warns. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, the commenter recommends that EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Commenter (2221-TPA) states that their understanding is that some state agencies with jurisdiction over air permits believe that these requirements would pose significant problems and that it would take a substantial amount of time and resources to address and incorporate this proposal into their permitting structures, given that their new source review programs do not have minor source permitting programs allowing for inclusion of GHG emissions.

Commenter (2227-WEA) states that the new methane applicability threshold creates an issue with state permits as it is a new criterion for which state permits would not have a direct limitation. The commenter states that the administrative process to modify these permits to address these new criteria is a very significant and unnecessary burden on owners, operators and permitting authorities without emissions reduction benefit. The commenter states that assuming the typical pace to process permits and depending on the number of permits that need to be modified, the process to modify permits can take upwards of ten years.

Response II-13-15: EPA agrees with the commenter that low levels of VOC are a reliable indicator of limited methane emissions. Reviewing the data in the docket, EPA estimated that 4 tons per year of VOC would likely be an appropriate level at which it can be assumed that a source would emit under 20 tpy methane [Docket Item No. EPA-HQ-OAR-2021-0317-0039, Attachment 21; based on worst-case ratio of VOC to methane; see “Oil” tab, row 33, data for “Sample Tank No. 52”]. While we agree in principle that some level of VOC may be an appropriate surrogate for applicability of a methane threshold, EPA did not propose the surrogate relationship of VOC emissions that can be reviewed by commenters.

The addition of methane as a regulated pollutant may require revision to state permit programs

generally, but such changes will not affect existing sources until a federal or state plan has been promulgated and such a limit in a permit is not a prerequisite for determining the potential for methane emissions. Responses to comments regarding legally and practicably enforceable limits may be found in Section 13.2.6. EPA stated in the supplemental proposal (87 FR 74832) that 18 months from final promulgation of this rule should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements. Those state plans would have up to a 36-month period from the final adoption of state rules to come into full compliance (87 FR 74836).

The applicability threshold for methane emissions applies to affected facilities that are new, modified, or reconstructed after December 6, 2022 (87 FR 74702). For existing sources, states have the opportunity to review EG OOOOc and adapt their state programs to the requirements of the final rules, a period which would be no less than a year and could extend up to 36 months for state 111(d) plans.

### ***13.2.6 Legally and Practicably Enforceable Limits***

Comment: Commenters (2298-Pioneer Natural Resources USA, Inc. (Pioneer); 2301- U.S. Chamber of Commerce (USCC), 2326-American Exploration and Production Council (AXPC), 2428-API) urge EPA to defer final action on the proposed definition of legally and practicably enforceable limits until such time as the Agency undertakes a national rulemaking. Commenter (2428-API) believes such a broad-based rule would prevent potential inconsistencies among the various CAA programs (*e.g.*, an effective emissions limit used to avoid major NSR permitting might, at the same time, not be effective for purposes of the NSPS OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the “effectiveness” criteria established under EG OOOOc should be applied under other CAA programs (*i.e.*, how can an emission limit be both effective and not effective at the same time); and would allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria. The commenter states they raised similar issues in the November 2021 Proposal and are raising them again, because EPA recently announced its intention to issue national guidance on establishing effective limits on PTE.<sup>12</sup> The commenter believes that effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990’s era D.C. Circuit decision that vacated or remanded the then “federal enforceability” criteria that applied across EPA’s CAA regulatory programs.<sup>13</sup> The commenter states that EPA’s announced plan to establish national rules for effective limits on PTE and to do so in the relative near future<sup>14</sup> lends strong additional support that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

Commenter (2326-AXPC) recommends that EPA set aside the definition of “legally and practicably enforceable” limit unless and until EPA completes a national rulemaking. The

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<sup>12</sup> NAAQS, Regional Haze & Permit Program Implementation Updates, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

<sup>13</sup> EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175, memorandum from Sean W. O’Donnell to Joseph Goffman (July 8, 2021) at 17.

<sup>14</sup> The commenter states that EPA intends to issue national guidance by October 2023.



commenter states that while the definition is within the context of determining storage vessel applicability under NSPS OOOOb and EG OOOOc, the concept of a legally and practicably enforceable limit is not limited to NSPS OOOOb/EG OOOOc storage vessels though, and its finalization will create much uncertainty across CAA programs, as other sources wonder whether EPA's newfound definition will apply in other contexts – *e.g.*, NSR permitting or section 111 performance standards for other source categories. The commenter states that a national rulemaking would avoid many potential inconsistencies and uncertainties across CAA programs and would allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

Commenter (2298-Pioneer) states that EPA should not define and impose practicably enforceability requirements without first developing a coherent approach for all EPA programs. The commenter believes that the question of what constitutes an acceptable and effective “legally and practicably enforceable limit” goes well beyond the four corners of this regulation and has implications far beyond this narrow regulatory provision. The commenter believes that this question is relevant across EPA's CAA stationary source programs: from major source permitting under New Source Review (NSR)/PSD, to the Title V operating permit program, to all manner of federal and state emissions control programs (of which CAA section 111 is just one). The commenter opines that what constitutes an acceptable and effective “legally and practicably enforceable limit” has been an open question since the mid-1990s, when the prior “federal enforceability” requirement was remanded or vacated across EPA's programs.<sup>15</sup> The commenter notes that EPA announced its intent to conduct a comprehensive rulemaking to address the holdings in these cases but has not yet taken action almost 30 years after the decisions were handed down. Addressing it in a piecemeal, rule-by-rule fashion will ultimately cause confusion and potential inconsistency across the relevant programs, the commenter states. Moreover, the commenter states, affected facilities and states now have years of experience implementing the NSPS OOOO and NSPS OOOOa storage vessel standards, including substantial experience in crafting appropriate emissions limitations to govern applicability of these standards. Creating new mandatory procedural requirements is unnecessary according to the commenter, given that no systemic problem has emerged during this long implementation period. The commenter believes that such requirements would add to the cost and burden of implementing these standards without delivering any commensurate benefit. The commenter recommends that EPA defer final action on the proposed definition until such time as the EPA undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs.

Response II-13-16: See discussion in Section XI.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2298-Pioneer) is concerned that the legally and practicably enforceable criteria could inadvertently call into question existing permitting and regulatory regimes that do not specifically include the parameters proposed by EPA.

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<sup>15</sup> *National Mining Ass'n v. EPA*, 59 F. 3d 1351 (D. C. Cir. 1995); *Chemical Mfrs. Ass'n v. EPA*, 70 F. 3d 637 (D.C. Cir. 1995); *Clean Air Implementation Project v. EPA*, 1996 WL 393118 (1995).

Response II-13-17: The EPA agrees the final requirements will result in coverage for the first time for numerous existing storage vessels, but not under OOOOb. Instead, the requirements that EPA is finalizing do not apply to existing sources before states have the opportunity to submit 111(d) implementation plans after state rulemaking takes place to reflect the emission guidelines. EPA has allowed states 18 months to carry out state rulemaking activity to adopt the appropriate emission guidelines and standards. In addition to the 18 months, EPA has recommended that states adopt compliance deadlines within 36 months, providing over 4 years for existing sources to adapt their systems to new federal and state standards.

Comment: Commenter (2301-USCC) is concerned with the proposed definition for the term “legally and practicably enforceable” as it relates to state emissions limits for “storage vessel affected facilities” that limit their potential for VOC emissions below 6 tpy. The commenter believes that in effect, if EPA deems applicable state standards not “legally and practically enforceable,” it would disregard the state limits and treat the storage vessels as uncontrolled for purposes of federal regulation.<sup>16</sup> The commenter is concerned that this proposal thus has the potential to create substantial friction between EPA and the states, and could result in many more facilities becoming subject to federal emission standards. The commenter believes that EPA’s proposed enforceability indicia put form over substance by ignoring how states *actually enforce* emissions limits in favor of a series of checkboxes. Based on these indicia, many state limits that states *actively enforce* could be deemed not “legally and practically enforceable,” despite states having years of experience implementing storage vessel standards and enforcing these standards, according to the commenter. The commenter recommends that EPA defer final action on any proposed definition of “legally and practicably enforceable” until such time as the agency elects to undertake a comprehensive, broad-based rulemaking to ensure consistency across CAA programs. The commenter is concerned that to otherwise proceed risks creating a piecemeal, rule-by-rule regime that would ultimately create confusion among regulated parties and state regulators and inconsistencies across CAA programs.

Response II-13-18: EPA disagrees with the contention of the commenter that the EPA is placing form over function with the legally and practicably enforceable criteria. As a legal matter, the revised criteria apply to OOOOb sources and would not apply to OOOOc EG sources until states act to designate sources and adopt their own plans under 111(d), meaning the number of existing sources subject to the OOOOc EG criteria will not increase until that time. As discussed in the November 2021 Proposal, EPA has reviewed some state limits, and believes they are too general to require a reduction in emissions. See 86 FR 63201. See also the examples provided in Section XI.J.1. of the preamble to the final rule. With respect to verifying compliance, EPA has not asserted that states are not enforcing limits, but EPA does believe that in some cases, the limits which are being enforced are not capable of achieving the required emissions reductions to stay below the potential for VOC emissions under the NSPS. EPA believes that establishing legally and practicably enforceable criteria for the oil and gas industry will create a level of certainty as to what EPA considers legally and practicably enforceable for the next generation of sources. This level of specificity and certainty will serve to guide states as they consider how to apply

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<sup>16</sup> See 86 Fed. Reg. at 63,202 (“Only those limits that include the elements described [in the proposed definition] will be considered ‘legally and practicably enforceable’ for purposes of determining the potential for VOC emissions from a single storage vessel or tank battery, and thus applicability (or nonapplicability) of each single storage vessel or tank battery as an affected facility under the rule.”).

these criteria through state requirements promulgated under OOOOc EG and through permits issued for OOOOb and OOOOc sources.

Comment: Commenter (2221-TPA) states that EPA should not add unduly prescriptive requirements associated with claiming emissions limits for storage vessels. The commenter urges EPA not to adopt the proposed new definition of what is considered a legally and practicably enforceable limit for storage vessels.<sup>17</sup> The commenter is concerned that EPA's proposed revisions to the concept of legally and practicably enforceable emissions limits in the context of storage vessel applicability thresholds are unduly prescriptive and that the proposal casts aside the traditional means of assessing PTE limits for threshold applicability purposes and replaces it with a highly prescriptive scheme that would constitute regulatory overkill and add uncertainty to whether and how limits could be claimed going forward. The commenter explains their understanding, that where a rule contains an emissions threshold under which a given piece of equipment is not subject to the rule's requirements, it is fair and logical that the equipment be considered outside of rule coverage where emission controls or limitations are in place to keep emissions below the threshold, even though in an uncontrolled state the equipment is capable of producing emissions above threshold levels. The commenter states that this concept has been embodied in EPA rules for decades<sup>18</sup> and was incorporated into NSPS OOOOa in 2016.<sup>19</sup> The commenter states that they are not aware that it has caused any significant problems or compliance issues in the context of NSPS OOOOa or more generally.

The commenter (2221-TPA) is concerned that EPA continues to take the position that an owner or operator would have to coordinate with the applicable permit authority to work out specific limits, monitoring requirements and recordkeeping that will ensure any permitted emission limit is achieved, whatever this might entail in a given circumstance. If all this does not occur, the commenter is concerned that presumably the result would be that an owner or operator would be unable to claim the existence of legally and practicably enforceable limits or throughput limitations keeping a storage vessel below the applicability threshold. The commenter states that this all is unnecessary regulatory overkill and would add significant burden and uncertainty to what should be a straightforward process. The commenter points out burden and complications that they say would be felt both by companies seeking enforceable limits and state regulatory agencies which might have to revisit permit terms in order to align permit conditions with the new requirements. The commenter is concerned that if that alignment could not be achieved, then EPA 's proposed new requirements would have the effect of placing numerous storage vessels into NSPS coverage for the first time, even if there had been no indication that the vessels had been circumventing controls that had kept PTE below threshold levels. In addition, it is the commenter's understanding that some state agencies with jurisdiction over air permits believe that these requirements would pose significant problems and that it would take a substantial amount of time and resources to address and incorporate this proposal into their permitting structures, given that their NSPS programs do not have minor source permitting programs allowing for inclusion of GHG emissions. The commenter also states that even if an

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<sup>17</sup> Our comments on this point are not limited to emission limits for storage vessels; any rule provisions that allow owners and operators to claim legally and practicably enforceable emissions limits should be free from the additional restrictions being proposed by EPA here, regardless of type of operation at issue.

<sup>18</sup> See, e.g., 40 CFR § 5 I. I 65(a)(I)(iii); 40 CFR § 5 I. I 66(b)(4); 40 CFR § 52.21 (b)(4).

<sup>19</sup> 81 Fed. Reg. 31500 (June 3, 2016).

owner or operator could satisfy every item required by the proposed criteria for “legally and practicably enforceable,” there would be the additional burden of translating compliance with those requirements into an arrangement with the permitting authority that may require rewriting existing permit authorization terms so that the permit would meet the criteria EPA has in mind. The commenter states that application of these new criteria would only work to hinder or eliminate the use of a concept that EPA (rightly) considered to be advisable in its 2016 promulgation of NSPS OOOOa and that EPA has employed for decades, in each case free from the restrictions EPA is now contemplating. In the context of relying on permit limits to claim reductions in PTE, the commenter believes it has long been EPA's position that “[w]hen permits contain production or operational limits, they should also have recordkeeping requirements that allow a permitting agency to verify a source's compliance with its limits.”<sup>20</sup> The commenter believes the requirement of an enforceable limit has always been and continues to be in place, per storage vessel applicability requirements at 40 CFR 60.5365a(e) that cognizable PTE limits must take the shape of “requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority.” The commenter summarizes that a permit limit is a permit limit, and it is inconceivable that there is any federal, state, or local permit that does not carry with it the ability of the issuing authority to ensure and enforce compliance if permit limits are exceeded. The commenter states that they recognize that reporting, recordkeeping, monitoring requirements will vary from permit to permit, but that all permits ultimately must be complied with or enforcement consequences from the issuing authority may follow. To the commenter’s knowledge, they state there is no permit that does not contain consequences for violations.

Response II-13-19: See discussion in Section XI.J.1. of the preamble to the final rule which details EPA’s final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2221-TPA) states that it is inaccurate to suggest (as they said that EPA did in the November 2021 Proposal), that a permitted emissions limit that does not contain one or more mechanisms to ensure or monitor compliance (*e.g.*, performance testing requirements, continuous or other monitoring requirements, recordkeeping and reporting provisions) is somehow less than enforceable or merely constitutes a “voluntary” limit that EPA should simply disregard. The commenter states that in no sense is an emissions limit memorialized in a permit voluntary; it is a legal requirement that must be followed, even if the particular monitoring or recordkeeping provisions contained in the permit do not reflect EPA's proposed new requirements.

The commenter (2221-TPA) recognizes that it is inappropriate to claim an enforceable limit if the limit is actually unenforceable in practice, but states that this issue has been present ever since the first time EPA implemented the concept of claiming limits on PTE and they do not think that circumstances surrounding claimed PTE limits have changed dramatically such that all the new requirements, burdens, and attendant uncertainty in EPA's proposal are justified.

Response II-13-20: EPA agrees with the commenter that an emissions limit memorialized in a permit is not a voluntary limit. EPA disagrees with the commenter that a limit in a permit is self-

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<sup>20</sup> EPA Memorandum, "Limiting Potential to Emit in New Source Permitting," Terrell E. Hunt and John S. Seitz (June 13, 1989) at 6.

evidently enforceable without more specific requirements that allow EPA or the state to determine ongoing compliance using field-gathered data summarizing ongoing compliance with the terms in the permit.

Comment: Commenter (2222-Wisconsin Department of Natural Resources (WIDNR)) states that the requirements for legally and practicably limiting the “potential for methane emissions” are unclear and conflict with the definition of “potential to emit.” Specifically, the commenter states:

- It is unclear why EPA has proposed that production limits must be accompanied by operational limits in order to be legally and practicably enforceable. (40 CFR 60.5386c(e)(2)(i)(A))
- It is unclear how a source would establish parametric limits for production and/or operational limits. (40 CFR 60.5386c(e)(2)(i)(C))
- It is unclear how a source would use a control device to meet an operational limit. (40 CFR 60.5386c(e)(2)(i)(C))

The commenter (2222-WIDNR) states that EPA should refer to the available case law and guidance on limiting “potential to emit” to ensure the use of terms such as “production limit,” “operational limit,” and “parametric limit” in the proposed rules are consistent with the widely accepted use of those terms in air permitting programs.

Response II-13-21: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA’s final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2258-MSA) suggests revisions or clarifications to the regulatory text regarding legally and practicably enforceable. At 40 CFR 60.5365b(e)(2)(i), the commenter asks EPA to clarify that a legally and practically enforceable limit applies to both; 1) an operating permit and, 2) other requirement established under a Federal, state, local, or tribal authority. At 40 CFR 60.5365b(e)(2)(i)(A), the commenter requests clarification that both a quantitative production limit, meeting criterion of 40 CFR 60.5365b(e)(2)(i)(B) and a quantitative operational limit are required. The commenter also asks that EPA confirm that more than one operational limit (*e.g.*, 95 percent control) that does not qualify as a parametric limit is required.

Response II-13-22: The EPA disagrees that the current references to “enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority” in 40 CFR 60.5365b(e)(2)(i) requires further clarification. The EPA disagrees with the need to specify that an operational limit of 95 percent control is not a parametric limit. Examples of parametric limits for control devices are typically flow rate, residence time, combustion zone temperature, visible emissions, or similar metrics of the control reaction or oxidation.

Comment: Commenter (2423-Coterra Energy, Co.) states that they support the proposed VOC and methane thresholds (*i.e.*, 6 tpy VOCs and 20 tpy methane) for a single storage vessel or a tank battery affected facility at new well sites, centralized production facilities, and compressor stations, but are concerned that the proposed criteria for establishing legally and practically enforceable limits will create confusion and burdensome compliance issues. The commenter explains that in administering the CAA, states establish limits that allow operators to keep below

permitting thresholds for both Title V and PSD thresholds. The commenter states that the oil and gas industry, as well as other industries, have come to rely on that practice. In turn, according to the commenter, states have adopted monitoring, recordkeeping, and reporting requirements as part of permits. Nevertheless, the commenter is concerned that existing permits in many states may not meet the criteria that EPA is proposing for legally and practically enforceable permit terms. The commenter believes that the proposed changes will require states to review and revise countless permits and also may require states to engage in rulemakings over and above the efforts states will be required to initiate to implement these rules. The commenter states that EPA has neither explained nor justified this policy change, as it must, and should retract it.

Response II-13-23: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2399-GPA) states that they provided comments on the definition of legally and practicably enforceable in their comments in response to the November 2021 Proposal and that for the purposes of the December 2022 Supplemental Proposal, they reassert and adopt those previous comments and objections as if fully stated here. In summary, the commenter states the following:

- Contrary to EPA's suggestion that this is codification of previous policy, EPA previously defined and used the term differently.<sup>21</sup> Therefore, regardless of EPA's intent, providing a new and different definition does not provide "clarity to owners and operators claiming the storage vessel is not an affected facility in NSPS OOOOb, due to legally and practicably enforceable limits that limit their potential for VOC emissions below 6 tpy."
- Rather than provide clarity, EPA's proposed definition—including quantitative production and operational limits, averaging time, parametric limits on performance testing, continuous monitoring, and recordkeeping and reporting thereof - is inconsistent with the long-standing definition, overly restrictive, excludes work practices and other control options, and effectively prohibits the use of permits by rule and general permits. EPA has not provided any reasonable justification for this shift from its previous position.
- EPA should not upend the state permitting process, which has long relied on the current understanding of legally and practically enforceable. Indeed, EPA has approved the state minor source permitting programs, which are part of the states' implementation plans. Based on those programs, sources have obtained permits and relied on the presence and operation of its controls to meet its regulatory requirements, such as the limit on VOC emissions from storage vessels. By substantially revising this definition - and apparently effectively assuming that controls are not in place - EPA would dramatically change the permitting landscape. Moreover, it is really putting the cart before the horse. If EPA believes state minor source programs generally require revision, there is a process for that and EPA should follow that process of generally revising state SIPs, as opposed to attempting to make changes in this regulation.
- Adoption of this legally deficient proposed definition would prove unworkable in practice and would require significant time and resources to implement, for which EPA

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<sup>21</sup> See 40 CFR 49.152, 49.167; 76 Fed. Reg. 38,748 (July 1, 2011); see also Prevention of Significant Deterioration and Nonattainment New Source Review: Debottlenecking, Aggregation, and Project Netting, 71 Fed. Reg. 54,235, 54,240 n. 13 (Sept. 14, 2006).

has not provided in its proposal. Among other concerns, these sources do not have methane limits in permits now. EPA's new approach offers no guidance on how to assess whether a particular set of parameters is legally and practically enforceable to achieve a methane limit in that case. Further, prohibiting the use of permits by rule and general permits would impose enormous burdens on sources and state permitting authorities, for which the proposal makes no provision. This would have a cascading effect on Title V determinations across numerous sources, imposing substantial additional burdens and complexities on sources and states.

The commenter (2399-GPA) states that if EPA decides to finalize the text, EPA should recognize that sources in good faith went to the regulator and obtained a permit under the applicable state minor source program. Thus, at a minimum, the commenter states that EPA should provide flexibility by phasing in the requirement and applying the new definition only when a source needs to apply for a new or revised permit or a permit renewal. Moreover, crucially, for all existing sources, the commenter states that EPA should be clear that existing permits authorizing a source to operate remain fully effective, pending state processing of new permits.

Response II-13-24: EPA disagrees that the criteria finalized in OOOOb is inconsistent with prior guidance. The language adopted reflects the tenets of guidance applicable to OOOO and OOOOa sources that remains applicable today. Such prior guidance includes the January 25<sup>th</sup>, 1995 memo from John Seitz to the Air Directors of all ten EPA regions titled "Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act)" and the January 25<sup>th</sup> 1995 memo from the Office of Enforcement and Compliance assurance from Kathie A. Stein, Director of the Air Enforcement. Division to all ten EPA regions titled "Guidance an Enforceability Requirements for Limiting Potential to Emit through SIP and §112 Rules and General Permits."

EPA is not adding regulatory language for legally and practicably enforceable limits in an effort to correct state permit programs. EPA enforces the NSPS as written and has chosen to add regulatory language for new affected sources under OOOOb to facilitate compliance on the part of owners and operators. EPA has obtained consent decrees for sources that failed to show compliance with the NSPS from owners and operators. The EPA did not obtain those consent decrees with state agencies.

With regard to the comment that existing sources do not have methane limits in permits now, see the discussion in the Final Preamble in Section XI.J.1.,

EPA's promulgation of these criteria is the basis of how the EPA will evaluate whether a facility is subject to legally and practicably enforceable emission limits for new and modified facilities under new and modified sources under OOOOb and existing sources under OOOOc EG. These criteria will apply going forward and will not be used to determine whether prior determination of OOOO/OOOOa applicability were accurate. As the EPA stated in our proposal and supplemental proposal, the enforcement record shows that there is a need for EPA to further specify what legally and practicably enforceable emissions limitation means in the oil and gas sector because we have found through enforcement actions that sources have relied on inadequate limitations to support their status as not subject to the storage vessel provisions of the

NSPS. However, the EPA disagrees with the comment that our action results in the need for all storage tank owners and operators to obtain site-specific permits. A permit-by-rule or general permit system that creates legally and practicably enforceable limits that meet the criteria would not require a site-specific permit. Further, no owner or operator is required under this provision to obtain any minor source permit. The owner or operator could instead comply with storage vessel requirements under OOOOb.

We also point out that the provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source designated facilities under OOOOc, and are not retroactively applicable to OOOO or OOOOa sources. The EPA enforcement cases to date have relied on EPA guidance and the provisions of OOOO and OOOOa, and will continue to do so.

Comment: Commenter (2254-PBPA) states that the definition of legally and practicably enforceable usurps state authority, and directly conflicts with how that term is used in other CAA programs. The commenter states that as a matter of practice, states have exercised their right to promulgate their own regulations that operators could take into account when determining PTE. The commenter believes individual states are much better equipped to determine the appropriate methods for the specific circumstances facing industries within their state and that process is required under EPA's regulations (when the states meet certain conditions). The commenter is concerned that the proposed requirements conflict with the approach used in both the Title V and NSR/PSD permitting programs. Under these programs, the commenter explains, operators may rely on control requirements to limit their PTE that would no longer be available under the Proposed Rule. In effect, the commenter is concerned that the Proposed Rule would arbitrarily require operators to have two different PTE calculations – one for Title V and NSR permitting and another for NSPS/EGs under the Methane Rule.

The commenter (2254-PBPA) states that the definitions of “potential to emit” and “federally enforceable” show that EPA's own regulations provide states with substantial latitude to establish “legally enforceable procedures.” The commenter cites to 40 CFR Part 51 for the definition of “potential to emit”<sup>22</sup> and “federally enforceable.”<sup>23</sup> Thus, the commenter states, the TCEQ emissions limits, established under its EPA-approved State Implementation Plan (SIP), are by EPA's own definition federally enforceable. The commenter also states that EPA previously determined that the regulations and permits issued by both the TCEQ and NMED were legally and practicably enforceable. The commenter states that in the preamble to the proposed 2013 amendments to NSPS OOOO, EPA reviewed the regulations in several states to determine which states already had storage tank control requirements for calculating PTE. Based on its evaluation of these regulations, the commenter states that EPA determined that several states already had sufficient regulations, including both Texas and New Mexico, such that EPA could subtract the storage vessels in these states “from the overall count of storage vessels that

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<sup>22</sup> “Potential to emit is the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable.” See, e.g., 40 CFR 51.165(a)(1)(iii).

<sup>23</sup> “...all limitations and conditions which are enforceable by the Administrator...[and] requirements within any applicable State implementation plan...”. Id. at 40 CFR 51.165(a)(1)(xiv).



would be subject to the final rule.” The commenter believes that EPA’s proposal to require a new definition of “legally and practicably enforceable” substitutes its own judgment as to what is legally and practicably enforceable when its own regulations say that determination should be left to the states, subject to EPA review. The commenter reminds EPA of its ability to weigh in on whether a state’s regulations are legally and practicably enforceable through the SIP review process. The commenter believes that when given the opportunity to review the regulations of Texas and New Mexico with regard to calculating PTE, EPA already has determined those regulations were federally enforceable.

Response II-13-25: EPA disagrees with the commenter that the legal basis for federal enforceability of SIP provisions addresses the criteria that EPA is promulgating for legally and practicably enforceable limits. EPA is promulgating the requirements that allow field data to be compared to operational and production limitations for the purpose of verifying compliance. This is fundamentally different than establishing the legal underpinning that make SIP provisions federally enforceable in general. EPA also disagrees that the definition of “potential to emit” cited by the commenter is relevant in this instance. The final rule provides that production limits must be accompanied by operational limits to be legally and practicably enforceable because potential VOC and methane emissions from a storage vessel are a function of the facility operational conditions and production rates. Consequently, both are inputs to the storage vessel emission calculations and changes in either may result in an increase in vessel emissions. Compliance with any emissions limit should be demonstrated by monitoring the operational conditions and production rates used to establish emissions from the storage vessel.

EPA disagrees that adopting regulatory language governing how the EPA will evaluate legally and practicably enforceable limitations usurps state authority to issue minor source permits. The NSPS applies to emissions from affected sources and does not serve as the legal basis upon which any source operates.

The EPA also disagrees that the criteria EPA is promulgating conflicts with other Clean Air Act programs. The commenter states in their comment letter that “Operators currently rely on the same regulations and permit conditions to comply with minor source permitting requirements under the Title V and NSR programs.” The EPA cannot understand how more specific criteria within the NSPS OOOOb that supports an ongoing demonstration of compliance can undermine compliance with Title V and NSR permits. The EPA repeats that existing sources subject to OOOO and OOOOa are not affected by the standards of OOOOb until they are modified or reconstructed, or until they become designated facilities under OOOOc EG in coming years. Even in the event that a conflict were to arise that EPA has not foreseen for existing sources, EPA contends that the time period to adopt state plans, designate facilities, and implement an existing source program is sufficient for sources and states to revise applicable requirements.

EPA rejects the view of the commenter that EPA substitutes its own judgement for that of states on what constitutes legally and practicably enforceable limitations, because EPA has been issuing guidance on that concept to states since 1995. EPA regularly enforces its own cases on the provisions of legally and practicably enforceable limitations, and EPA points out that our decision to adopt regulatory criteria for legally and practicably enforceable limitations in this rule is based on review of actual permits, which were not revealed by (or apparent from)

reviewing the state regulations. In summary, it is EPA's responsibility to ensure that NSPS is effectively implemented.

EPA agrees that in promulgating OOOOb and OOOOc EG that thousands of sources may become subject to additional emission control regulations, since the purpose of section 111(b) and (d) is to reduce emissions for new, modified, reconstructed, and existing sources, some of which pre-date subpart OOOO standards promulgated in 2012. EPA disagrees that the emissions from these sources do not warrant regulation, which can be reviewed in the RIA.

Comment: Commenter (2298-Pioneer) believes that permits obtained from the TCEQ would show all of the legally and practicably enforceable requirements, however the commenter believes the proposed requirements are vague and they seek clarification. The commenter points to the first requirement, “quantitative production limit and quantitative operational limit” and they believe these requirements are shown in the state TCEQ permit, however, the commenter asks if operators need to obtain a federal permit on top of the state permit. Because the air permitting SIP was approved by EPA, and TCEQ has received delegation to run their permitting program, the commenter strongly recommends that EPA specify that the certified state permit suffices in demonstrating that tank batteries are under the required threshold limit of 6 tpy VOCs. Generally, the commenter believes that the SIP approval and delegation should provide the assurances EPA needs to rely on the state agency.

Response II-13-26: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA’s final standards for legally and practicably enforceable emissions limitations. EPA cannot provide the permit shield suggested by the commenter, because EPA has found through enforcement actions that certain state permits do not contain the provisions necessary under EPA guidance to constitute a legally and practicably enforceable limitation. We also point out that the provisions finalized in this action are applicable to new, modified, and reconstructed sources under the NSPS OOOOb generation of sources, and existing source designated facilities under OOOOc EG, and are not retroactively applicable to OOOO or OOOOa sources. The EPA enforcement cases to date have relied on EPA guidance and the provisions of OOOO and OOOOa and will continue to do so. On the issue of requesting a federal permit, this would only be possible for a source located on federal land where the Administrator is the permitting authority, or where a state or local permitting authority does not have delegated authority to issue permits. A list of states and other jurisdictions with delegated authority can be accessed under 40 CFR Part 70, Appendix A to Part 70—Approval Status of State and Local Operating Permits Programs.<sup>24</sup>

Comment: Commenter (2298-Pioneer) requests that EPA define “parametric limits” to mean the ongoing monitoring of production and operational limits.

Response II-13-27: See response I-9-14 and discussion in in section at Section X.J.1. of the preamble to the final rule which details EPA’s final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2483-INGAA) states that the elements that a legally and practicably

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<sup>24</sup> See <https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-70#Appendix-A-to-Part-70>.

enforceable limit must include under proposed 40 CFR 60.5365b(e)(2)(i)(A)-(F) are too prescriptive, and indeed wholly inappropriate. The commenter points out that states (and EPA) have been establishing federally and practically enforceable limits for decades under Title V, the NSR programs, and the hazardous air pollutants (HAP) provisions of the CAA. The commenter believes that there is no reason for EPA to require in this rulemaking a prescriptive approach such as that proposed here. In addition, the commenter states that the elements that EPA requires in the December 2022 Supplemental Proposal are wholly inappropriate – as they unduly restrict the discretion of permitting authorities and go well beyond what is typically needed for federally and practically enforceable limitations.

By way of example, the commenter (2483-INGAA) states that proposed 40 CFR 60.5365b(e)(2)(i)(A) requires a “quantitative production limit and quantitative operational limit(s) for the equipment, or quantitative operational limits for the equipment.” The commenter is concerned that if EPA intends this proposed provision to require a standalone production limit or operational limit, that is inconsistent with long-standing EPA policy. The commenter believes that production and/or operational factors can be used as part of a parametric calculation of emissions, but they need not be standalone.<sup>25</sup> Finally, the commenter takes issue with proposed 40 CFR 60.5365b(e)(2)(i)(C) which requires that “where a control device is used to achieve an operational limit, an initial compliance demonstration (*i.e.*, performance test) for the control device that establishes the parametric limits.” While the commenter agrees that the regulations should certainly allow the use of a compliance demonstration, presumably in the form of a test, there is no reason for EPA to preclude other means of estimating the control device efficiency, such as AP-42 factors or vendor-provided factors, especially when these factors are known to be conservative.

Response II-13-28: EPA disagrees with the characterization by the commenter that specifying what EPA requires for the next generation of sources to comply with OOOOb and OOOOc EG restricts the discretion of state permit authorities. The Administrator retains the authority to enforce the NSPS, and promulgate the requirements to which sources must adhere to be in compliance. A source is not required to avail themselves of a legally and practicably enforceable limitation, but in the event that they do, such limitations must meet the criteria in OOOOb, and designated sources will be required to meet OOOOc EG. States are not required to issue legally and practicably enforceable emissions limitations, but in the event that they do, it is in the interest of the permittee, the permit authority, and EPA that EPA specify upon promulgation the metrics and standards that EPA will require of sources to show ongoing compliance.

The commenter expressed concern that the legally and practicably enforceable limit criteria somehow required a “standalone” production limit or operational limit. EPA replies that the production and operational limits may rely on several factors including parametric measurements that show compliance.

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<sup>25</sup> See, e.g., In re. Salt River Project Agua Fria Generating Station], Petition No. IX-2022-4, at 12-13 (Adm’r July 28, 2022), available at [https://www.epa.gov/system/files/documents/2022-08/SRP%20Agua%20Fria%20Order\\_7-28-22.pdf](https://www.epa.gov/system/files/documents/2022-08/SRP%20Agua%20Fria%20Order_7-28-22.pdf),

(“EPA does not interpret the federal regulations to require production and/or operating limits in all situations.”).

The EPA disagrees that using only emission factors for control devices as a demonstration of compliance with a legally and practicably enforceable limitation is sufficient to show compliance for a controlled source in the oil and gas category. See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2483-INGAA) states that proposed 40 CFR 60.5365b(e)(2)(i)(B) requires an averaging period of less than 30 days when a production-based limit is used, but the commenter believes that is arbitrary and capricious, as well as inconsistent with EPA policy, where the overall standard that the limit is intended to enforce is a tons per year (*i.e.*, annual) standard. In such a case, as here, a 12-month rolling limit, as long as it is well defined in how it is calculated, is more than adequate, according to the commenter<sup>26</sup>.

Response II-13-29: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2292-West Virginia Office of the Attorney General *et al.*) believes that EPA's proposed definition of "legally and practically enforceable" in the specific context of storage vessels, which would push aside state regulation of emissions from this sector. The commenter believes that this shows that EPA will disregard the state limits and treat the storage vessels as uncontrolled, and rather than respect state rules limiting emissions, EPA starts from a place of skepticism, effectively assuming it can supplant any state regulation that EPA considers inadequate based solely on its own disagreement. The commenter is concerned that this presumption of federal control destroys the cooperative federalism that the CAA prescribes. The commenter is concerned that EPA is ignoring the State's expertise, even though States have extensive and useful experience regulating emissions for decades.

Response II-13-30: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2428-API) believes that the proposed legally and practicably enforceable criteria and the additional methane emissions threshold may be impossible to obtain under existing permitting mechanisms. The commenter states that EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. The commenter is concerned that EPA's proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

The commenter (2428-API) believes that the proposed revisions are inconsistent with EPA's reliance on states to administer the CAA with regard to Title V and PSD. That is, the commenter states, EPA allows states to establish emission limits on sites that keep sites below Title V and

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<sup>26</sup> [See, e.g.,] Memorandum from John S. Seitz, Director, EPA Office of Air Quality Planning and Standards, to EPA Regional Air Division Directors, [Options for Limiting the PTE of a Stationary Source Under Section 112 and Title V of the Clean Air Act], at 6 (Jan. 25, 1995), available at <https://www.epa.gov/sites/default/files/documents/limit-pt-rpt.pdf> (explaining that "annual limits such as rolling annual limits" are appropriate to practically enforce an annual emission limitation).

PSD permitting thresholds. The commenter believes that EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria, which according to the commenter, has long been an effective approach to reduce recordkeeping burden while reducing potential emissions. The commenter states that the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. The commenter is concerned that existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. By way of example, the commenter states that permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. The commenter believes that EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is “*periodic reporting that demonstrates continuous compliance*,” according to the commenter. Historically, the commenter points out, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National NESHAP, which the commenter states is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources, according to the commenter. The commenter recommends that for streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective, according to the commenter.

The commenter (2428-API) does believe that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for 40 CFR 60.5365b(e)(2)(i) (suggested deletions are shown in strike-through):

For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.

Response II-13-31: No owner or operator is required under this provision to obtain any permit meeting the legally and practicably enforceable criteria. The owner or operator could instead comply with storage vessel requirements under OOOOb. See also the discussion in section at Section X.J.1. of the preamble to the final rule which details EPA’s final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2227-WEA) believes that the proposed provisions for legally and practicably enforceable would render many state permits ineligible for determining storage tank applicability. The commenter urges EPA not to codify the requirements for meeting the definition of legally and practicably enforceability, and instead continue to defer to states for regulations and permitting. Further, the commenter states that the new methane applicability

threshold creates an issue with state permits as it is a new criterion for which state permits would not have a direct limitation. The commenter states that the administrative process to modify these permits to address these new criteria is a very significant and unnecessary burden on owners, operators and permitting authorities without emissions reduction benefit. The commenter states that assuming the typical pace to process permits and depending on the number of permits that need to be modified, the process to modify permits can take upwards of ten years. Because of these concerns, the commenter believes that EPA should continue to defer to states for establishing appropriate monitoring, recordkeeping, and reporting.

Response II-13-32: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

Comment: Commenter (2202-TXOGA) urges the Agency to establish common sense transition rules for any new requirements legally and practically enforceability. The commenter believes that EPA has the ability to place these transition provisions directly into the regulations to provide regulatory certainty to companies and to avoid drastically overburdening state agencies, which are already behind in processing Title V renewals. In particular, the commenter states, EPA should provide that 6 tpy VOC permit limits will be deemed to satisfy any new legal and practical enforceability requirements. The commenter states that EPA should provide the revisions be conducted either during the next Title V renewal for the source (provided such renewal is at least one year after rule issuance) or at the next significant permit modification under Title V. For non-Title V sources, the commenter recommends that the transition rules should provide a five-year period to allow sources to obtain necessary permits, recognizing that overburdened states will typically allocate resources to major sources first.

Response II-13-33: See discussion in section at Section X.J.1. of the preamble to the final rule which details EPA's final standards for legally and practicably enforceable emissions limitations.

### ***13.2.7 Potential to Emit***

Comment: Commenter (2254-PBPA) states that the proposal to use uncontrolled PTE would conflict with both existing state permitting programs and conflict with other CAA programs that allow for and account for "legally and practicably enforceable" limits. The commenter states that not allowing the use of controls in the PTE evaluation for storage tanks and tank batteries results in practically every storage tank becoming an affected facility under the proposed NSPS. Further, the commenter states it is their understanding that under the proposed rule, emissions events and upset conditions are considered as part of the PTE calculations. According to the commenter, emissions events and upset conditions are unauthorized emissions under TCEQ rules, thus, including emissions events or other upset events in the methane PTE representations assumes noncompliance. The commenter suggests that instead of assuming such noncompliance, these types of events should be addressed through enforcement procedures, not NSPS. Similarly, the commenter believes that instances when the vessels are not operating as designed should not be included in an NSR authorization. Consistency between PTE evaluation for the NSR program and this NSPS is critical, according to the commenter. The commenter states that if EPA does not intend to include emission events and upset conditions in calculating PTE, it should make that clear in its PTE calculation methodology.

Response II-13-34: EPA believes the commenter is conflating the November 2021 proposal for fugitives monitoring frequency based on total site-level baseline methane emissions, with the requirement to determine the potential for VOC and methane emissions for storage vessel applicability. In the November 2021 proposal, EPA requested comment on whether, for purposes of determining which proposed monitoring frequency would apply, sites should use the uncontrolled PTE calculation for their storage vessels in their site-level baseline estimate to account for times when these vessels are not operating as designed. See 86 FR 63171. However, as explained in the December 2022 supplemental proposal [and is reference to RTC chapter on fugitives needed?] EPA did not propose to establish fugitive emissions monitoring frequency on total site-level baseline emissions, so the comment is moot. See 87 FR 74722.

When determining storage vessel applicability, the final rule continues to allow legally and practicably enforceable limits to be included in the determination of whether a storage vessel is an affected facility. Further, upset conditions and their resulting emissions are not included in the determination. Under 40 CFR 60.5365b(e)(2)(ii), the provisions do not require that upset conditions be included in the maximum average daily throughput, which forms the basis for determining the potential for VOC and methane emissions from storage vessels.

The commenter expressed that the criteria for legally and practicably enforceable emissions limitations in the NSPS raises their concerns about how this new interpretation/approach would apply in the Title V and New Source Review (“NSR”)/Prevention of Significant Deterioration (“PSD”) context where operators are relying on the same control requirements to limit their PTE. EPA points out that promulgation of standards under a specific rule are not applicable to other categories. EPA is promulgating these criteria to address a specific type of source within this category that EPA intends to address proactively by applying the criteria going forward. Any change to the criteria for legally and practicably enforceable emissions limitations proposed under Title V, NSR, or any other rule would be subject to notice and comment rulemaking where the commenter would have the opportunity to comment.

Comment: Commenter (2353-CrownQuest Operating, LLC (CrownQuest)) has concerns with the tank battery applicability when determining the potential for emissions. The commenter is concerned that EPA is stretching past the limit of what an atmospheric tank is used for and treating it like a pressured vessel. Regarding the potential for emissions, the commenter points out that NSPS OOOOa, which has been in place for 12 years, determined each tank should be 6 tpy. The commenter states that proposed rule has not identified any instances of how the existing per-tank interpretation has affected emission reductions, but instead made a new BSER for what the EPA prefers to say. The commenter is concerned that this change will only make the industry adjust how they have been calculating the PTE for the past several years, and it is unlikely that there will be any significant number of instances where this change would affect anything other than to increase costs on the industry and require more work for the EPA. All facilities, according to the commenter, including the combination of tanks, must be below 25 tpy, hence if a facility has five tanks, it would already have to limit the emission as the combination of tanks at 6 tpy per tank would be above the statutory limit. The commenter states that other emissions calculations, such as fugitive, must be factored in that limit that number even further. Therefore, according to the commenter, the industry’s common practice of putting controls in place on all

tanks is necessary as there is not an easy or cost-effective way to isolate the tanks to put controls on some and not on others.

Response II-13-35: The commenter may be considering that a formerly uncontrolled atmospheric storage vessel that is connected by a liquid line will now be considered part of a battery subject to a 6 tpy VOC limit for the entire battery, and therefore have to be modified or replaced to be controlled. In such a scenario, the facility would not be subject to OOOOb, unless modified or reconstructed. The facility may be a designated facility by OOOOc EG, and may in fact become an affected facility if it was not already. Under our BSER analysis the EPA asserts that control of such vessels will reduce emissions and that the reduction is cost-effective. This is why EPA disagrees with the premise of the comment that regulating tanks on a per-tank basis is as effective as regulating tanks on a battery-basis given the many tank configurations that exist. In discussion with industry across multiple rulemakings to modify OOOO and OOOOa, and through EPA's own field work, EPA learned that the critical factor for determining whether a series or group of tanks was operated as a single system was whether they were linked by liquid line. While many tank batteries may be manifolded together by vapor lines and headspace, both that requirement and the requirement the tanks in the tank battery be adjacent has been discarded for OOOOb and OOOOc EG. The EPA further disagrees that requiring that a tank battery be subject to control at 6 tpy VOC and 20 TPY methane, regardless of the number of tanks, is less protective of the environment because each tank in the tank battery must achieve the emissions reduction. Lastly, the EPA points out that a tank battery subject to control must control all of the tanks in the battery and there will not a scenario where some tanks are controlled and others are not. Other commenters have specifically asked for the flexibility to use multiple closed vent systems and controls within a single tank battery, in contrast to this comment. The EPA agreed with the other commenter in that a situation could arise that multiple control devices used for a single battery could be an effective control strategy under the standard, as long as each tank in the tank battery is equipped with a cover, closed vent system and routed to a control device which achieves a 95% reduction in emissions.

Comment: Commenter (2483-INGAA) recommends flexibility for owners/operators to document their potential for emissions, especially if EPA retains methane as an applicability basis. The commenter request that reasonable assumptions for transmission and storage compressor station operations (e.g., frequency of tank turnover) be deemed sufficient to demonstrate that emissions are less than 20 tpy, because permit programs may not always provide an avenue for documenting methane emissions PTE in a permit limit. The commenter believes that when adding a methane emissions threshold to NSPS OOOOb and EG OOOOc, EPA did not consider whether current permitting programs include methane emissions and/or whether tank emissions would be below permitting *de minimis* thresholds. The commenter explains that some states, such as West Virginia and North Dakota, do not include tanks with low emissions in their permits. The commenter states that as proposed, owners/operators may not have a pathway to document that a storage vessel or tank battery is exempt, so it is imperative that EPA address this issue. The commenter is concerned that while EPA may determine that state program updates are warranted, that could take time to implement, and EPA should not ignore the current status. Thus, owner/operator records documenting PTE emissions less than the applicability threshold, where the emissions calculations are based on operations characteristics of transmission and storage compressor stations, should suffice (with recordkeeping), and a legal, federally



enforceable permit condition should not be required, according to the commenter. Further, the commenter states that the determination that applicability thresholds are not exceeded should be on a 12-month rolling basis.

The commenter (2483-INGAA) cautions that is a reasonable pathway to document emissions less than the threshold is not provided, operators must undertake onerous and costly actions to otherwise prove status. For example, the commenter states that 40 CFR 60.5396c(a)(3) allows an operator to comply with a 14 tpy uncontrolled methane emissions rate, but only after demonstrating a 95 percent methane emission reduction for twelve months. Thus, the commenter states, if reasonable and documented emission estimates (in lieu of a federally enforceable permit limit) are not allowed to confirm emissions less than the threshold, a transmission and storage tank with emissions well less than 14 tpy would first have to install and demonstrate 95 percent control for a year before being allowed to comply with the “uncontrolled” emission limit. The commenter believes that EPA developed these provisions with higher emitting upstream operations in mind (*i.e.*, high flashing losses and much more frequent tank turnover) and did not consider the implications for tanks at transmission and storage compressor stations.

Commenter (2483-INGAA) also believes the language at 40 CFR 60.5386c(e)(2), “[t]he determination *may* take into account requirements under a legally and practicably enforceable limit in an operating permit or other requirement established under a Federal, state, local, or tribal authority” (emphasis added) allows that a legally and practicably enforceable limit is needed only when the owner relies on an operating limit or other requirement to establish the PTE; conversely, if a straightforward calculation demonstrates methane emissions are less than 20 tpy based on operations associated with the transmission and storage compressor station, the tank is exempt without the need for a permit limitation. Further, the commenter believes the two methodologies in subparagraphs (A) and (B) of 40 CFR 60.5386c(e)(2)(iii) are clear that subsection (A) requires a permit limitation, while subsection (B) does not. Because the legally enforceable limit required in subparagraph (A) can be problematic for transmission and storage operators (because permits are not accessible for a low emitting tank), operator documentation of the associated emission calculation assumption can provide assurance that the exclusion is appropriate. The commenter requests that EPA confirm the intent of this provision. With respect to legally and practicably enforceable limits, the commenter recommends that EPA revise the elements to make them consistent with current, long-standing policy - for example allowing but not requiring standalone production and operational limitations and acknowledging that a rolling 12-month limitation is more than adequate to ensure conformance with an annual applicability threshold.

Response II-13-36: To address the commenters’ concern that certain states do not have permit programs that allow operators to avail themselves of a limitation under the NSPS, EPA included the provisions for legally and practicably emission limitations in the promulgation of OOOO and OOOOa, and did not condition the use of this mechanism to state permitting programs. Rather states were able to use permits by rule or general permits to issue such limitations, so long as they met the prior guidance. EPA’s promulgation of new criteria under OOOOb and OOOOc EG did not change in this respect for sources subject to NSPS OOOO and OOOOa and EPA is not making any determination that states must update their programs, beyond the necessity to respond to our proposal of OOOOc EG.

EPA notes that the long-standing premise of storage vessel applicability is based the potential for VOC, which may take into account legally and practicably enforceable limits. In this rulemaking, EPA is not departing from that premise (except to include methane), but is establishing specific criteria which are considered legally and practicably enforceable. As discussed elsewhere (see I-9-22), EPA is choosing to add regulatory certainty to describe legally and practicably enforceable emissions limitations now, because of the issues discussed in the November 2021 proposal, namely that when reviewing the limits considered by these facilities as legally and practicably enforceable, EPA believes the limits do not require a reduction in emissions as they are often of such a general nature as to be unenforceable or otherwise lack measures to assure the required emission reduction. See also examples of such limits in Section I-9-15. If the EPA were to choose to issue another round of guidance, states and sources would not have the same level of certainty as to what EPA considers legally and practicably enforceable for the next generation of sources. This level of specificity and certainty will serve to guide states as they consider how to apply these criteria through state requirements promulgated under OOOOc EG and through permits issued for OOOOb sources. A calculation demonstration alone is not legally and practicably enforceable under these criteria.

Regarding the language at section 60.5465b(e)(2), the commenter is correct that the application of legally and practicably enforceable requirements is an option available to owners and operators when determining the potential for VOC and methane emissions. As the commenter notes, subparagraph (A) of section 60.5365b(e)(2)(ii) specifies that throughput must be established as a legally and practicably enforceable limit. Subparagraph (B) of section 60.5365b(e)(2)(ii) does not require a legally and practicably enforceable limit, because the potential for emissions is determined using the maximum design capacity of the facility, which by definition is not limited. The provisions of section 60.5365b(e)(2)(ii) are the same as the provisions in 60.5365a(e)(2)(ii), which were added in September 2020<sup>27</sup> to address comments from midstream operators that the “first 30-days” of production was not meaningful in many cases for storage vessels downstream of well sites. The commenters stated that:

Compressor stations (including gathering and boosting compressor stations) and onshore natural gas processing plants typically utilize process simulations based on representative or actual liquid analysis to determine potential VOC emissions and volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each facility. These generally accepted engineering models and calculation methodologies are then utilized to obtain Federal, state, local, or tribal authority issued permits to set legally and practicably enforceable limits to maintain potential VOC emissions from storage vessels at less than 6 tpy. 85 FR 57427.

EPA agreed and stated:

Based on the above reasons, the EPA is amending the 2016 NSPS subpart OOOOa to specifically provide the following two options for determining the potential for VOC emissions from storage vessels at facilities downstream of well sites. The first option, which is already allowed in the 2016 NSPS subpart OOOOa, allows owners or operators to take into account throughput and/or emission limits incorporated as legally and practicably enforceable limits in a

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<sup>27</sup> See 85 FR 57427.

permit or other requirement established under a Federal, state, local, or tribal authority. The second option allows the use of generally accepted engineering models (*e.g.*, volumetric condensate rates from the storage vessels based on the maximum gas throughput capacity of each producing facility) to project the maximum throughput used to calculate the potential for VOC emissions. 85 FR 57427.

Because the commenter to this rulemaking asks the question regarding the difference between subparagraph (A) and subparagraph (B) of 60.5365b(e)(2)(ii) regarding the need for a legally and practicably enforceable limit, EPA is adding the term “design” to subparagraph (B) to make clear the calculation is based on the unlimited design capacity of the site. Subparagraph (B) is finalized as follows (additions underlined):

(B) Determine the potential for VOC and methane emissions using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses and based on projected maximum average daily throughput. Maximum average daily throughput is determined using a generally accepted engineering model (*e.g.*, volumetric condensate rates from the tank battery based on the maximum design gas throughput capacity of each producing facility) to project the maximum average daily throughput for the tank battery based on design conditions.

Finally, EPA agrees that a 12-month rolling average is an acceptable averaging period to determine compliance with a 30 -day limit where the rolling 12-month average is supported by 30-day subtotals, beginning in the first 30-days and redetermined every month.

Comment: Commenter (2483-INGAA) states that the proposed requirements for establishing the PTE of storage vessels, which heavily emphasize that any limitations must be made legally and practicably enforceable in a state-issued permit, ignore the practical reality that many state agencies do not process permits for low emitting tanks in transmission and storage service because the actual emissions of these tanks are far below the states’ permitting thresholds. The commenter states that these provisions are unworkable and urges EPA instead to adopt provisions exempting storage vessel affected facilities for which the owner documents that emissions from the affected facility will not exceed the applicability thresholds under any expected operations of the facility, and in fact do not exceed the thresholds on a 12-month rolling basis.

Response II-13-37: EPA disagrees that provisions of legally and practicably enforceable are unworkable, because they are based on prior guidance that has been applied in OOOO and OOOOa dating back to 2012. EPA also points out that obtaining a site-specific permit is not the only way to approach such a limit. States have used permits by rule or general permits to regulate storage vessels with low levels of emissions, and these types of permits may apply automatically to specified sources without further processing by States. Subparts OOOOb and OOOOc that the EPA finalized today do not necessarily require a site-specific permit. Other mechanisms may be used, as long as the LPE definition is met.

### ***13.2.8 Determination of Potential Emissions***

Comment: Commenter (2172-Kentucky Oil and Gas Association (KYOGA)) states that accurately determining emissions from a tank or tank battery that is used to store crude oil produced from a single source, well or lease, is very difficult and potentially very expensive for a small operator. The commenter believes it may be EPA's intention to force operators to engage engineering firms to plan tank and tank battery construction and operation, to capture a few new previously uncontrolled vessels. The commenter states that sampling an uncontrolled storage tank is very difficult, both technically and physically. For older tanks, potentially subject to EG OOOOc, the commenter states that they have estimated that there are over 12,000 active tank batteries in Kentucky, the vast majority operated by small operators. The commenter points out that many small operators rely on the "TANKS" software to simply, quickly, and inexpensively generate expected VOC working and breathing emissions. The commenter states that while the emission estimates that the Tanks program generates may not be 100 percent accurate, it is consistent with historic practices. However, according to the commenter, EPA's inclusion of flashing emissions and methane eliminates an operator's ability to use the TANKS program and changes will be required to TANKS to address methane emissions, as the current version only accounts for VOC emissions. The commenter points to an EPA statement in the proposed rule, that EPA is including "regulatory text which instructs the owner or operator on how to determine the potential for VOC or methane emissions as the cumulative emissions from all storage vessels within the tank battery according to certain timelines." The commenter interprets this as if there is a published guide to calculating tank emissions based on EPA's proposed new emission standards. However, the commenter states they have been unable to find it and provide comments to EPA. The commenter recommends that EPA update the TANKS software so that small operators can estimate emissions in a low-cost way.

Response II-13-38: Because flashing emissions are often the largest contributor to storage vessel emissions in the production sector, a generally accepted model or calculation methodology must account for flashing, as well as working and breathing losses. Because the basic "TANKS" software does not calculate emissions from flashing, it should not be used to assess the potential to emit from the storage of fluids that were previously stored under pressure, including oil and condensate from producing wells. It is not the EPA's intention to force operators to engage engineering firms to plan tank and tank battery construction and operation, but it is necessary for operators to accurately assess the potential emissions from the well's tank battery. There are a number of software systems that account for flash emissions from the tank battery, including WinSim, Designer II, HYSIM, HYSIS, VMG, PROMAX, and E&P Tanks (API Publication 4697). While the EPA is currently working to update the TANKS software model based on the equations in Chapter 7 of AP-42, Section 7.1.3.5 of AP-42 specifically notes that "The equations in Section 7.1.3.1 for estimating routine emissions from fixed roof tanks do not address the scenario of a tank storing a liquid which contains gases that have the potential to flash out of solution... There are numerous methodologies available for estimating flashing losses and specific guidance regarding their application and use. However, discussion of such methodologies is beyond the scope of this section." Consequently, even when updated, the TANKS software model will not be capable of estimating flashing losses.

Comment: Commenter (2399-GPA) states that the applicability determination methodology for compressor stations and natural gas processing plants should be revised, given the new interpretation of “legally and practicably enforceable limits,” and the lack of certainty regarding the enforcement of state-issued permits that renders the prior NSPS OOOOa and proposed NSPS OOOOb text and approach no longer appropriate. The commenter understands that under the proposal, emission calculations for these sources would be based upon the projected maximum daily average vessel throughput derived from the maximum gas throughput capacity of each facility. In most cases, the commenter states, this would significantly overstate actual tank battery emissions and the effect would be to premise applicability determinations on the site’s design capacity, not actual emissions or even engineering estimates of throughput used for NSR permit authorizations of the site (*i.e.*, a methodology based upon the maximum gas throughput capacity is used to calculate PTE thresholds for NSR permits). However, the commenter cautions, condensate production is not easily estimated as it is a combination of liquid that drops out of field gas during compression and condensate that drops out of the gas along the pipeline to the station or plant and is dependent on several factors, including weather conditions that change throughout the year. The commenter states that EPA’s methodology will ensure that many storage tank batteries would be deemed subject to NSPS OOOOb, even though they would be exempt based upon actual throughput data. As such, the commenter urges EPA to allow for qualified engineering estimates, instead of design capacity. For new compressor station sites, the commenter explains that permit calculations are generally submitted prior to construction, based upon engineering estimates of liquid throughput based on expected gas design capacity. The commenter states that this is not the same as storage vessel design capacity, which may be much higher. For existing sites that are modified, the commenter explains that existing throughput data is used in combination with engineering estimates of any expected throughput increase. The commenter cautions that in neither case would the maximum design capacity be used to estimate VOC or methane emissions from the storage tank battery. Instead, the commenter states, engineering estimates based upon expected throughput are much more accurate than assumptions of maximum throughput capacity for the site. Additionally, in permitting hourly and annual emission limits, frequently the maximum hourly emission limit does not match the annual limit due to issues with variability in storage vessel throughput across an entire year, according to the commenter. The commenter explains that owners or operators must obtain a permit for any new tank battery, the reconstruction of a tank battery, or the modification of a tank battery (where a tank is added, total capacity will increase, or the actual throughput will exceed the current permit or most recent NSPS OOOOb determination). In each instance, according to the commenter, owners or operators must submit an emissions estimate prior to startup. The commenter suggests that engineering estimates, signed by a qualified individual or professional engineer involved with the project, should be used in lieu of maximum design capacity. The commenter states that they understand that these estimates infrequently may underestimate the actual throughput once the site comes online, but to account for this, the commenter suggests that the throughput estimates be compared to actual operating data within 30 days of startup to ensure accuracy. The commenter believes this approach is consistent with current requirements under NSPS OOOOa and the definition of “maximum daily throughput.”

Response II-13-39: As discussed in Response II-13-36, EPA provided two options to determine the potential for emissions from storage vessels at facilities downstream of well sites in September 2020. In short, the provisions allowed for a legally and practicably enforceable limit

on throughput, or an engineering determination of maximum average daily throughput based on maximum design capacity (typically gas throughput) of the site. These provisions were added in response to comment from midstream operators that the first 30-days of production might not be accurate for certain scenarios. EPA proposed these same options in December 2022 in OOOOb and OOOOc.

EPA understands from the comment, that because of the legally and practicably enforceable criteria which EPA proposed and is finalizing, the limits which midstream operators have relied on to limit the emissions through a permit may not be “legally and practicably” enforceable under the finalized criteria, leaving only the option to determine maximum average daily throughput based on design capacity. According to the commenter, this would significantly overstate actual tank battery emissions and the effect would be to premise applicability determinations on the site’s design capacity, not actual emissions or even engineering estimates of throughput, which are used for NSR permit authorizations of the site. The commenter asserts that actual emissions would better estimate emissions to determine whether the tank is greater than 6 tpy VOC or 20 tpy methane and is asking that EPA provide a third means to determine applicability for tanks applicable to these instances. Their comment suggests that engineering estimates, signed by a qualified individual, should be used in lieu of maximum design capacity. The commenter further states that they understand that these estimates may underestimate the actual throughput once the site comes online, but to account for this, the commenter then suggests that the throughput estimates be compared to actual operating data within 30 days of startup to ensure accuracy.

First, EPA notes that the final legally and practicably enforceable criteria applies to storage vessel affected facilities subject to NSPS OOOOb and the presumptive standards for storage vessel affected facilities under the EG and does not apply retroactively to sources subject to NSPS OOOO or OOOOa. Regarding an alternative to the proposed criteria, the EPA disagrees that a determination based on “qualified” engineering estimates and/or actual throughput is a workable approach, absent memorializing such a determination in a permit, which under the final rule, must meet the legally and practicably enforceable criteria. Any “qualified” or actual limit which is less than design capacity would have to be verified against the engineering estimate, or actual production would have to be measured (among other criteria as specified by the final legally and practicably enforceable limits) to assure ongoing compliance. We do not think that the commenter envisioned a system that required on-going verification, because the commenter suggested only one verification 30 days after startup and expressed concerns with acquiring permits with the legally and practicably enforceable criteria. Further, the commenter explained that condensate production is not easily estimated as it is a combination of liquid that drops out of field gas during compression and condensate that drops out of the gas along the pipeline to the station or plant and is dependent on several factors, including weather conditions that change throughout the year. For the EPA, this calls into the question the representativeness of one month of condensate production to verify applicability. The final rule does allow for an actual uncontrolled mass emissions limit of 4/14 tpy, after one year of compliance with the 95% reduction and records demonstrating that emissions have remained below those limits for 12 consecutive months.

Comment: Commenter (2428-API) believes that in terms of the PTE calculations, centralized

production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on “a projected maximum average daily throughput.” Therefore, the commenter offers the suggested redlines for 40 CFR 60.5365b(e)(2)(ii) and 60.5365b(e)(2)(iii) (suggested additions are underlined; suggested deletions are shown in strike-through):

(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.

As an alternative, the commenter suggests another solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

Response II-13-40: EPA disagrees that centralized production facilities are more akin to compressor stations and gas plants than well sites. As discussed at 86 FR 63184, EPA understands that the activities at centralized production sites are the same types of operations as would be conducted at the individual well sites. The commenter did not provide sufficient information to understand why this premise is not correct. Therefore, the EPA is not making the changes suggested by the commenter.

Comment: Commenter (2177-Ute Indian Tribe) suggests the following change to OOOOc: “The potential for methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working, and breathing losses, based on the projected maximum average daily throughput to the tank battery determined for a 30-day period of production.””(suggested additions are underlined; suggested deletions are shown in strike-through).

Response II-13-41: In reconsideration of the 2011 rule for NSPS OOOO<sup>28</sup> EPA determined that 30 days was the appropriate timeframe for determining the potential for emissions from a storage vessel affected facility. In further amendments to NSPS OOOO<sup>29</sup> the EPA explained that because “we believe it is important to achieve control of storage vessel affected facilities as soon

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<sup>28</sup> See 78 FR 58416.

<sup>29</sup> See 79 FR 79018.

as practicable, we believe it is important to begin the 30-day period for estimating storage vessel VOC PTE as soon as this estimation can be achieved and will provide a representative estimate of the storage vessel's PTE during production.”<sup>30</sup> In September 2020<sup>31</sup>, the EPA finalized an alternative determination process for storage vessels not located at well sites, because the first 30-days of production at these types of sites (e.g., natural gas processing plants and compressor stations) may not be representative of the maximum throughput for which they are designed.

We do not believe that existing tank batteries at well sites will not be able to determine the maximum average daily throughput during a 30-day production period after the effective date of an approved state or tribal plan. These sites have been producing for some period of time, and the 30-day production period should be representative of the potential for methane emissions. The commenter did not explain why “projected” maximum average daily throughput would provide a more accurate representation of the potential for methane emissions than a determination based on a 30-day period of production, therefore, the EPA is not making this change.

### ***13.2.9 Modification of Storage Vessel Affected Facility***

Comment: Commenter (2218-Texas Commission on Environmental Quality and Railroad Commission to Texas) states that the modification definitions between NSPS OOOOa and NSPS OOOOb are different and that for a well site applicable to NSPS OOOOa, any changes to the well that increase throughput will have to be evaluated differently under both rules. The commenter provides by way of example that NSPS OOOOb proposes that a storage vessel modification can be triggered if there is a throughput increase and if the resulting VOC or methane emissions are greater than the specified thresholds, but under NSPS OOOOa, the modification definition is tied to a new well, or changes to an existing well. The commenter is concerned that the differences in applicability criteria may cause confusion with both regulators and regulated entities, which again will lead to longer review times for permit applications and compliance evaluations.

Response II-13-42: EPA does not agree that the differences in modification provisions between OOOOa and OOOOb sources are significant. Upon promulgation of OOOOb the modification provisions of OOOOa are moot. Other changes to the storage vessel provisions are intended in part to simplify applicability for tanks in general, whether they are part of a battery of multiple tanks or a single tank. With respect to tank modification as a function of a well modification, the EPA has opted to change tank modification to better address the concern of midstream tank operators that receive product from assets they have little control over or even knowledge of daily activity that could affected their facility status. See response II-13-47 for additional discussion.

Comment: Commenters (2172-KYOGA; 2298-Pioneer; 2248-NDPC) are concerned about the modification provisions related to replacement of a storage tank. Commenter (2248-NDPC) also is concerned about the modification provisions related to relocation of a storage vessel. Commenter (2172-KYOGA) states that an operator of an unregulated tank or tank in a battery

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<sup>30</sup> See 79 FR 79026.

<sup>31</sup> See 85 FR 57405.



that reaches the end of its safe operational life and must be replaced should not be required to have to prove the tank or tank battery should still be unregulated. The commenter explains that many oil and gas wells typical of legacy production are limited only in their productive life by the life of the tubulars in them (as exhibited by the many 100+ year old wells still producing in the Appalachian Basin of east Kentucky). The commenter believes that operators should be permitted to replace equipment in kind (e.g., akin to a “standard set” for the Refining industry) and should not be burdened with potentially expensive compliance activities for replacing equipment that has reached the end of its useful life. The commenter believes that if EPA finalizes the modification provisions as proposed, many operators will not replace equipment and it will result in more emissions from equipment not being replaced to avoid EPA’s compliance requirements.

Commenter (2298-Pioneer) recommends that replacement of a tank that only increases battery capacity should not trigger a modification because an increase in tank capacity does NOT equal an increase in emissions and, therefore, should not be considered a modification under any rule.

Commenter (2248-NDPC) states that certain activities which EPA is proposing which potentially trigger a modification include activities that are not a “physical change in, or change in the method of operation of, a stationary source” as required by CAA section 111(a)(3). By way of example, the commenter points out that the definition of modification in the proposed rule could include the relocation or replacement of a storage vessel. The commenter also states that EPA has not demonstrated the necessity of this change nor how its implementation will benefit the environment.

Response II-13-43: See discussion in section at section X.J.2. of the preamble to the final rule which details EPA’s final standards for modification.

Comment: Commenter (2326-AXPC) is concerned that EPA has departed from the definition of modification found at 40 CFR 60.14 and recommends that EPA limit modifications to where the operator increases emissions from the tank battery by increasing the capacity of the tank battery. The commenter explains that as proposed, subparagraphs (A) and (B) of 60 CFR 60.5365b(e)(3)(ii) would trigger a potential modification even where the increase in capacity of the tank battery is not accompanied by an increase in the tank battery’s emission rate. By contrast, the commenter says that their proposal would ensure consistency with 40 CFR 60.14 by requiring a capital expenditure on the potential affected facility accompanied by an increase in emissions. The commenter states that operators may readily track and document the addition or replacement of storage vessels within a tank battery. The commenter cautions that if EPA does not define modification to require an increase in the emissions rate of the tank battery, that perverse outcomes may occur. By way of example, the commenter explains that an operator may increase the size of tank battery without increasing the emissions from the tank battery, and if the emissions (which have not changed) exceed the applicability threshold, the tank battery would become an affected facility. The commenter explains that this possibility is real given that EPA now proposes to apply the 6 tpy VOC and 20 tpy methane applicability thresholds to the entire tank battery, where it previously under NSPS OOOO and NSPS OOOOa used the same VOC threshold but on an individual storage vessel basis, which effectively reduces the NSPS applicability threshold proportionally by the number of individual storage vessels in a tank

battery. Regarding subparagraphs (C) and (D) of 40 CFR 60.5365b(e)(3)(ii), the commenter states that the proposed criteria regarding increases in liquid throughput are too broad and are inconsistent with 40 CFR 60.14(e)(2) and should be removed. The commenter explains that per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification and EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, the commenter states, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as operators typically track liquid throughput using tank gauging rather than flow meters. Further, the commenter explains, the modification criteria for tank batteries at well sites and centralized production sites serves as a disincentive to the centralization of facilities, as the addition of production from a new well to an existing centralized production facility would trigger a modification under 40 CFR 60.5395b(e)(3)(ii)(C). If EPA does not remove the criteria at 40 CFR 60.5395b(e)(3)(ii)(C), the increase in liquid throughput also must be accompanied by a capital expenditure to the tank battery itself. The commenter explains that some actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself. The commenter recommends other clarifications to subparagraph (C). First, the commenter believes that EPA should remove the reference to “process unit” in subparagraph (C), because “process unit” is defined in the rule within the context of facilities that process natural gas, not well sites and centralized production facilities and the reference to process unit in the context of well sites and centralized production facilities is confusing and misplaced. Second, the commenter states that EPA should limit the scope of subparagraph (C) to “actions taken with respect to equipment that directly, or through a series of equipment, provides crude oil, condensate, intermediate hydrocarbons, or produced water throughput to the tank battery, including the addition of, or change to, a production well (including hydraulic fracturing or refracturing of the well).” By way of example, the commenter explains that hydraulic fracturing activities occurring in the vicinity of a well that delivers produced liquids to a storage tank battery may temporarily increase production of the well, which would, in turn, increase throughput of the tank battery, but as drafted, it is unclear whether this increase in production is an “action” that modified the tank battery if it resulted in exceedance of the potential for emissions threshold. The commenter believes it should not as operators cannot plan for or anticipate increases in production from activities occurring off-site that are outside the scope of operations associated with the tank battery. Further, in this example, the commenter explains that the cause of a temporary increase in production may be unknown to the operator and considering “actions” having no direct relationship to equipment in the definition of modification would be a far and extreme departure from longstanding NSPS modification principles. If EPA retains these modification triggers, the commenter requests that well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit as is allowed for compressor stations and natural gas processing plants. The commenter believes this recommendation would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Response II-13-44: See discussion in section at section X.J.2. of the preamble to the final rule which details EPA’s final standards for modification.

EPA must defer to a case-by-case determination on the comment asking that EPA determine that an action "...from activities occurring off-site that are outside the scope of operations associated with the tank battery" is not an action that results in a modification because of the seemingly site-specific circumstances of the example. The commenter seems to be citing an example of hydraulic fracturing at a nearby well that induces a change in throughput to tanks at another unrelated well site or centralized production facility. EPA cannot draft rules that account for every eventuality such as changes in well production as a result of nearby well drilling activity. Regarding temporary increases in throughput, the modification actions do not have a temporal element. For the reasons discussed in the November 2021 proposal, EPA believes the actions will result in emissions increase to the atmosphere. See 86 FR 63198. Limitations on throughput may be accounted for in a legally and practicably enforceable limit when determining the potential for VOC and methane emissions, which is conducted after one of the actions occurs.

Regarding the term "process unit", see discussion in section at Section X.J.2. of the preamble to the final rule which details EPA's final standards for modification, including the term "process unit."

To the request that EPA clarify that 40 CFR 60.14 does not apply to storage vessels, the EPA instead states in Table 7 of the NSPS that to the extent any provision in §60.14 conflicts with specific provisions in subpart OOOOb, it is superseded by subpart OOOOb provisions.

Comment: Commenter (2326-AXPC) requests that EPA clarify that it does not intend for operators to maintain records of potential emissions calculations for any of the actions in 40 CFR 60.5365b(e)(3)(ii)(A) through (D) that do not result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in 40 CFR 60.5365b(e)(1)(i) or (ii). The commenter explains that if one of these actions does not result in the potential for VOC or methane emissions to exceed the storage vessel applicability threshold, then a modification did not occur, and NSPS OOOOb would not apply, including recordkeeping requirements, but that this is not clear in the December 2022 Supplemental Proposal. Lastly, the commenter requests that EPA clarify that the storage vessel "modification" definition in 40 CFR 60.5365b(e)(3)(ii) is the singular controlling "modification" definition for NSPS OOOOb storage vessel affected facility determinations and that the modification definition in 40 CFR 60.14 does not apply.

Response II-13-45: We disagree with commenters that they are not required to maintain records of these evaluations. The evaluation is required under the rule. This record is needed to verify the rule does not apply. We have authority under CAA section 114(a) to require owners/operators of emission sources (not just regulated sources) to establish and keep records necessary for, among other purposes, determining whether anyone is in violation of the standard or for carrying out any provision of the CAA. Here the record is necessary to show that the NSPS is effectively implemented and that any claim of non-applicability status is accurate. Such record keeping requirement is common. See, e.g., 40 CFR 63.10(b)(3).

Comment: Commenter (2403-PAO) requests that in order to determine if a modification occurs, the rule should allow that operators can provide information that shows that emissions are not increasing and if emissions are not increasing, a modification has not been triggered.

Response II-13-46: The definition of modification included in the final rule at section 60.5365b(e)(3)(ii) does not provide that an owner or operator can show that emissions are not increasing (after conducting one of the actions specified in that section) to determine that a modification did not occur. In section IV.J.1.b of the December 2022 Supplemental Proposal,<sup>32</sup> EPA explained the rationale as to why we believe these specific actions lead to an increase in the VOC and methane emissions from a tank battery and therefore constitute a modification of an existing tank battery. Therefore, under the final rule, an existing tank battery or single storage vessel will become subject to the NSPS if one of the actions in this definition of modification occur and the potential VOC or methane emissions are greater than or equal to the 6 tpy VOC/20 tpy methane emissions threshold as determined in accordance with section 60.5365b(e)(2). An existing storage vessel that undertakes one of those actions, but does not surpass the applicability threshold remains an unaffected facility. A storage vessel that undertakes one of the actions can accept a legally and practicably enforceable emission limitation such that emissions will remain below the applicability threshold and will not be subject to the NSPS.

The commenter does not dispute EPA's rationales for the two-part test of modification. Rather the commenter suggests a case-by-case determination of no emission increase, which we believe to be unlikely. Further, since sources claiming non-applicability do not need to report to EPA, in light of the potential universe of thousands of tanks cited by the commenter, not including future new and modified tanks, it would be impossible for EPA to investigate each potentially incorrect claim of non-applicability.

Comment: Commenter (2399-GPA) is concerned that the proposed definition of modification includes the mere receipt of “additional fluids which cumulatively exceed the throughput used in the most recent ... determination of the potential for VOC or methane emissions.” The commenter states that these modification requirements are not feasible, as the midstream owner/operator is not the producer. The commenter explains that the owner or operator of midstream tank batteries at compressor stations or natural gas processing plants have no control over the receipt of fluids from upstream production facilities owned by third parties - midstream companies take possession of liquids at the custody transfer point and lack information regarding the upstream exploration and production company’s production volume prior to that point.

Commenter (2399-GPA) also states that attempting to define a change in throughput as a modification is contrary to law because under the CAA, a mere increase in throughput without any capital expenditure, other physical change to the equipment, or change in the method of operation is not a “modification.” See 42 U.S.C. § 7411(a)(3). The commenter states that the December 2022 Supplemental Proposal is not only inconsistent with the statutory definition of “modification,” but it is inconsistent with EPA’s prior interpretation that a “modification” requires some physical change to a tank. See Letter from Valdus Adamkus, EPA Region 5, to Bradley Miller, Hamilton County Environmental Services (Mar. 25, 1996) (increase in vapor pressure resulting in increased tank emissions was not a “modification” under 40 C.F.R., Part 60, Subpart Kb because there were no physical changes to the tank). The commenter is concerned that, unless the proposed definition of “modification” is revised to require a physical change or change in the method of operations, midstream owners and operators could find their equipment

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<sup>32</sup> 87 FR 74801 (December 6, 2022).

“modified” solely based on the decisions of upstream third parties and without taking any action themselves.

Response II-13-47: See discussion in section at Section X.J.2. of the preamble to the final rule which details EPA’s final standards for modification. Regarding the comment that the owner or operator of midstream tank batteries at compressor stations or natural gas processing plants have no control over the receipt of fluids from upstream production facilities owned by third parties, EPA previously finalized a different framework for estimating emissions at compressor stations and natural gas processing plants. See 85 FR 57404. Also, the commenter explained in response to the November 2021 proposal, that for midstream facilities, an upstream facility adding or refracturing a well simply means receiving a relatively minor volume of additional product, which is part of routine operations and is evaluated in potential to emit calculations during permitting activities and that the receipt of additional product is not a change to the regulated facility itself and the routine changes in product volume are already accounted for by permitting agencies as part of the facility design. See Comment and Response I-9-35. In response to this comment, in the December 2022 Supplemental Proposal, EPA agreed that as long as the additional throughput is accounted for in the design capacity of the tank battery and included in a legally and practicably enforceable limit for the tank battery, the additional throughput does not result in emissions increase from the tank battery because those emissions have already been accounted for in the permit. See 87 FR 74802. EPA proposed language to that effect at §60.5365b(e)(3)(ii)(D). The commenter did not explain why this proposed regulatory language does not resolve the issues raised by the commenter nor did the commenter provide alternative regulatory language for EPA’s consideration. EPA therefore is finalizing, as proposed, the requirements regarding modification actions at natural gas processing plants and compressor stations. In summary, a tank battery at a natural gas processing plant and compressor station is modified if one of the actions (adding a storage vessel to an existing tank battery, replacing one or more storage vessels such that the cumulative capacity of the tank battery increases, or the existing tank battery receives additional fluids which cumulatively exceed the throughput used in most recent determination of the potential for VOC or methane emissions) occur and the potential for VOC or methane emissions meet or exceed the thresholds.

Regarding the comment that a modification must include a capital expenditure see discussion in section at section X.J.2. of the preamble to the final rule.. With respect to the comment that a modification must include a physical change or change in the method of operation, EPA believes that the addition of a storage vessel to an existing tank battery and the replacement of one or more tanks such that the cumulative storage capacity of the existing tank battery increases are physical changes. As explained in the November 2021 proposal, EPA believes that the receipt of additional fluids is an operational change, unless for natural gas processing plants and compressor stations, the throughput has been accounted for in a legally and practicably enforceable permit.) See 86 FR 63199.

Comment: Commenter (2298-Pioneer) recommends that the addition of a tank(s) to an existing battery should not trigger a modification. The commenter explains that adding a tank to an existing battery which is already controlled under existing rules/regulations does not increase emissions. Because the commenters tank storage systems are all manifolded, the addition of one or more tanks without a corresponding increase in production would not increase emissions,

according to the commenter. The commenter suggests either (1) removal of this from the definition or (2) change the language to include a corresponding increase in production at the tank battery.

Response II-13-48: With regard to the general definition of modification of tank batteries, see discussion in section IV.J.1.b of the December 2022 Supplemental Proposal.<sup>33</sup> The definition of tank battery no longer includes the requirement that a tank vapor space be manifolded to the other tank vapor spaces in the battery to be part of the battery. Rather, a tank is part of a battery if it is connected by liquid line to other tanks.

The commenter's scenario of adding a tank to a tank battery already controlled under existing rules/regulations appears to mean connecting a tank by liquid line at a tank battery which contains one or more storage vessel affected facilities which are subject to either subpart OOOO or OOOOa. As explained in section XII.B.1.c of the November 2021 proposal<sup>34</sup>, EPA believes that even if the type and quantity of fluids processed remains the same, the increased storage capacity from an added tank will lead to higher breathing losses and therefore an increase in emissions. The EPA also explained the outcome with respect to applicability from such a scenario (Scenario 3), in the December 2022 Supplemental Proposal.<sup>35</sup> The commenter did not explain why this assumption is incorrect. Even if emissions are controlled, absent installation of a control device capable of achieving greater than 95% control, an increase in gas throughput to the control device will result in a corresponding increase in controlled emissions to the atmosphere.

Comment: Commenter (2298-Pioneer) recommends that increasing throughput to an existing tank should only trigger a "modification" if the increase in the PTE exceeds permitted levels. The commenter recommends that EPA define "increasing throughput" in accordance with how tanks are managed through the state permitting process. By way of example, the commenter states that these facilities typically are permitted at maximum design production throughput based on equipment at the site and then a limit is set. The commenter states that if they operated under that limit (regardless of decreases or increases in throughput), the commenter is in compliance with the permits. The commenter suggests including language that specifies an increase in production above permitted PTE would be considered a "modification."

Response II-13-49: See discussion in section XII.B.1.c. of the December 6, 2022, Supplemental Proposal<sup>36</sup> for special provisions for modifications related to increases in throughput at compressor stations and natural gas processing plants which account for increases above permitted limits. See also Response II-13-46.

In the November 2021 Proposal, EPA described that an event like hydraulically fracturing or refracturing a well increases the volumetric throughput of the tank battery and will increase working losses and potentially increase flashing losses. See 86 FR 63198. Under the modification provisions of the final rule, the action triggers the need to determine applicability against the VOC and methane potential for emissions thresholds. There is nothing to preclude the

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<sup>33</sup> 87 FR 74801 (December 6, 2022).

<sup>34</sup> 86 FR 63198 (November 15, 2021).

<sup>35</sup> 87 FR 74803 (December 6, 2022).

<sup>36</sup> 87 FR 74802 (December 6, 2022).

owner or operator from using previous legally and practicably enforceable limits, including limitations on throughput, when determining the potential for VOC and methane emissions after a modification action.

Comment: Commenter (2428-API) believes that the proposed definition of modification requires clarification. The commenter supports the first two proposed criteria for modification found in 40 CFR 60.5365b(e)(3)(ii)(A) and (B): “*A storage vessel is added to an existing tank battery*” and “*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*” because both of these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the commenter states that the proposed criteria in 40 CFR 60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and inconsistent with 40 CFR §60.14(e)(2). The commenter cites to 40 CFR 60.14(e)(2), where an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. The commenter states that EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, the commenter explains, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, the commenter believes that 40 CFR 60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification.<sup>37</sup>

However, the commenter (2428-API) states, if EPA decides to include increases in liquid throughput as a criterion for modification, the following changes are recommended:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself. These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

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<sup>37</sup> Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions “result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)” (the PTE-based applicability thresholds for storage vessels). But we note that EPA’s proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA’s rationale and to provide meaningful comments.

- **Reference to process unit in 40 CFR 60.5365[b](e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.
- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites.
- **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, the commenter offers the following suggested edits to 40 CFR 60.5365b(e)(3)(ii) (suggested additions are underlined; suggested deletions are shown in strike-through):

“Modification” of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)(C)~~ of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

(A) A storage vessel is added to an existing tank battery;

(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or

~~(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).~~

~~(D)(C)~~ For tank batteries at compressor stations or onshore natural gas processing plants, A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)(C)~~ of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.



Response II-13-50: See discussion in section at Section X.J.2. of the preamble to the final rule which details EPA’s final standards for modification, including capital expenditure and the term “process unit.”.

Regarding liquid throughput, the EPA notes that the action in paragraph (e)(3)(ii)(C) anticipates that the activities described will result in an increase in liquids throughput and a resulting emissions increase. At that point, the owner or operator of a tank battery at a well site or centralized production facilities must determine the potential for VOC and methane emissions. EPA agrees that a legally and practicably enforceable emission limitation could be applied in the context of determining the potential to emit resulting from a modification action. For example, an existing storage vessel that commenced construction before promulgation of 40 CFR 60 subpart OOOO that modifies under the conditions of OOOOb can apply a legally and practicably enforceable emission limitation when assessing the potential to emit to remain an existing (pre-OOOO) facility.

As a practical matter, however, the EPA is concerned with the statement that an owner or operator has difficulty tracking liquid throughput; if liquid throughput is expected to be used as a legally and practicably enforceable limit to maintain VOC and methane emission below the applicability threshold, then in accordance with the finalized criteria for legally and practicably enforceable, those limits must be tracked. The specific criteria for what constitute legally and practicably enforceable are discussed elsewhere in this chapter.

EPA interprets the last comment that all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs to refer to provision that a storage vessel at a well site is modified if the well is modified by hydraulic fracturing or refracturing of the well. The EPA disagrees because hydraulic fracturing or refracturing by its nature is to increase production and throughput such that an emissions increase is inevitable, unless a more stringent legally and practicably enforceable limit on the emissions reduction achieved by a control device is applied. Thus, we find it reasonable and necessary to require a re-evaluation of the potential to emit after any of the described modification actions.

#### ***13.2.10 Reconstruction of Storage Vessel Affected Facility***

Comment: Commenter (2403-PAO) provides responses to questions raised by EPA in the December 2022 Supplemental Proposal. With respect to EPA’s request for comment regarding the assumption that the cost to replace all depreciable components on a single storage vessel could exceed 50 percent of the cost of an entirely new storage vessel, the commenter states that typically, tank components such as tank hatches and pressure relief devices would not exceed 50 percent of the cost of an entirely new storage vessel. With respect to whether a specific timeframe for reconstruction is appropriate for determining reconstruction to a tank battery with more than a single storage vessel, and whether that time frame should be a 2-year time frame, the commenter agrees with this requirement and believes it will provide operators with a clear way to determine if reconstruction has been triggered.

Response II-13-51: See discussion in section at Section X.J.2. of the preamble to the final rule which details EPA’s final standards for reconstruction.

Comment: Commenter (2428-API) states that the proposed definition for reconstruction is internally inconsistent. The commenter cites EPA’s rationale in the proposal, that for a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that “*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility.*” However, the commenter points out, for a tank battery consisting of a single storage vessel, the existing provisions of 40 CFR 60.15 apply on the chance that the cost of replacement storage vessel components could be 50 percent or more of the cost to construction a comparable new storage vessel. The commenter explains that either the cost of depreciable components on a storage vessel other than the tank itself could be 50 percent or more of the cost of a new comparable tank or not. The commenter is concerned that this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, the commenter believes that operators should have the option to track either storage vessel replacements or all depreciable components. Based on this recommendation, the commenter offers the following redline of 40 CFR 60.5365b(e)(3)(i) (suggested additions are underlined; suggested deletions are shown in strike-through):

“Reconstruction” of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.

~~(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of 60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or~~

~~(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.~~

Response II-13-52: See discussion in section at Section X.J.2. of the preamble to the final rule which details EPA’s final standards for reconstruction.

Comment: Commenters (2305-Williams, 2433-EDF *et al.*) support EPA’s proposed definition of “reconstruction” for storage vessels. Commenter (2433-EDF *et al.*) believes it is reasonable for EPA to equate replacing 50 percent of tanks at a site with replacements where “the fixed capital cost of components exceeds 50 percent of the fixed capital cost that would be required to construct a comparably entirely new facility.” The commenter states that because individual tanks are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of tanks being replaced at a site and

the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility. Regarding the appropriate timeframe when determining if a reconstruction has occurred, the commenter supports mirroring the two-year rolling reconstruction time frame proposed for pneumatic controllers. The commenter believes that a two-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with storage tanks is actually pursuing an extensive tank replacement program, within the EPA's original intent in promulgating 40 CFR 60.15. The commenter believes the two-year timeframe also recognizes that it may be more cost-effective for operators to replace a larger portion of their tanks rather than initiate several, smaller replacement programs. Without a two-year window, the commenter is concerned that operators could create multiple replacement programs below the 50 percent threshold over the course of several years to avoid compliance with NSPS OOOOb. The commenter cautions that allowing this loophole would undermine Congress' intent that air quality be enhanced over the long term with the turnover of polluting equipment and with the intent of EPA's reconstruction provisions.

Commenter (2305-Williams) generally agrees with EPA's proposed regulations characterizing modification and reconstruction of storage vessels. The commenter believes that addition or replacement of a storage vessel that results in an exceedance of 6 tpy VOCs qualifies as a modification. The commenter also agrees that an increase in condensate or produced water throughput above a previous permit level that results in an exceedance of 6 tpy VOCs qualifies as a modification. The commenter believes the same holds true for methane, if EPA significantly increases its current methane threshold limit of 20 tpy. The commenter supports EPA's proposed reconstruction with respect to storage vessels and agrees with EPA that 2 years is a reasonable time during which activities potentially resulting in reconstruction should be evaluated.

Response II-13-53: See discussion in section at Section X.J.2. of the preamble to the final rule which details EPA's final standards for reconstruction.

## **13.3 BSER**

### ***13.3.1 General***

Comment: Commenter (2428-API) requests that EPA clarify that location is not a restriction on the use of a floating roof tank. The commenter notes that in 40 CFR 60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, the commenter points out that EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof, according to the commenter. The commenter offers a recommended redline to 40 CFR 60.5395b(b)(2) (suggested deletions are shown in strike-through):

For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection,

recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

Commenter (2248-NDPC) asks that EPA clarify what storage vessel types they propose to regulate under the oil and gas rules, as the BSER analysis only appears to address fixed roof tanks.

Response II-13-54: The EPA explained that production operators may not use floating roof tanks to meet the requirements of OOOOb, or OOOOc EG at well sites and centralized production facilities because floating roofs are not designed to handle flash emissions, which are prevalent in the production segment, a point that the commenter does not dispute. See 86 FR 63184. Storage vessels that do not have flashing emissions and that are not located at well sites or centralized production facilities may use floating roof controls following the provisions in subpart Kb.

### ***13.3.2 Technical Considerations***

Comment: Commenter (2362-EIP) states that current NSPS rules require new storage tanks with the potential to emit 6 tons or more of VOCs (without controls) to control tank vapors by installing flares or VCUs and operating them with a destruction removal efficiency (DRE) of 95 percent. The commenter notes that the proposed rule extends the same requirement to new and existing storage tanks with the potential to emit (PTE) 20 tons or more of methane per year. When calculating the cost-effectiveness, the commenter notes that the EPA assumes that a storage tank with a 20-ton PTE for uncontrolled methane would release about 91 tons of VOCs per year. As the commenter noted previously, they are concerned that the EPA has not obtained data from oil and gas sources to support its claim that 95 percent DRE represents the BSER for existing flares and vapor combustion units.

Response II-13-55: See response II-13-15 with respect to EPA's choice of 20 tpy as the applicability threshold for methane. See the EPA memo describing the BSER analysis [Docket Item No. EPA-HQ-OAR-2021-0317-0039].

Comment: Commenter (2353-CrownQuest) urges EPA to acknowledge the limitations of atmospheric tanks and their design to be at atmospheric pressure and understand that any additional pressure they hold to manage emissions is an improvement. The commenter states that EPA should not create new regulations that cause even more potential issues, including the potential for rupture and bodily harm from field personnel. The commenter believes that EPA's current rules are sufficient, and nothing in the new proposed rules will significantly affect emissions, although they will increase the cost of operating locations with tanks.

Response II-13-56: The EPA disagrees that the new NSPS OOOOb and EG OOOOc storage vessel requirements will not reduce emissions. See the RIA in the docket for the reductions that EPA estimates will be derived from the final storage vessel requirements. The EPA points out that the reductions quantified in the RIA are attributed to in part to the change in the definition of an affected facility tank battery will reduce emissions significantly as a result of more storage

vessels requiring control, as emissions averaging across tanks will no longer be the technique to determine the requirement to control emissions. With respect to atmospheric tanks, the NSPS exempts atmospheric tanks from controls if they demonstrate that uncontrolled emissions are below 4 tpy. For storage vessels with potential to emit greater than 6 tpy but that choose to accept legally and practicably enforceable emissions limitations, new criteria have been added to the NSPS to provide robust criteria to ensure such emissions limitations are met. We anticipate that these robust criteria applied by operators will decrease emissions from their storage vessels. Both the 4 tpy VOC threshold for uncontrolled tanks and the 6 tpy VOC threshold for controlling tank emissions are unchanged from OOOO and OOOOa, so we are not able to identify the commenter's concern regarding standards that could cause a rupture of storage vessels that present a risk to personnel.

Comment: Several comments provided feedback on EPA's proposed thief hatch monitoring provisions. Some of the specific comments are provided in the following paragraphs.

Commenter (2353-CrownQuest) has concerns with the thief hatch monitoring provisions. The commenter states that open or partially closed tank hatches is a human error issue that arises from the remote nature of oil and gas sites. The commenter points out that operators monitor most sites only minutes a day or every few days due to their remote locations and open tank hatches periodically to measure the contents of the tanks. The commenter notes that EPA already does not allow open tank hatches, and the industry has worked on limiting them over the years. The commenter urges EPA to revisit its 12 years of data to realize how little open hatches would be affected by this massive increase in paperwork and reporting. To the contrary, the commenter believes this has been an industry focus for years, and it is difficult to refute that instances have decreased without increased regulation. Further, the commenter believes that monitoring thief hatches with optical gas imaging (OGI) is a misuse of technology because it is easy to see if tank hatches are open, and the commenter states that OGI will not achieve that any better.

Commenter (2403-PAO) believes that EPA should not include a requirement to equip thief hatches with alarms, automated systems to monitor for pressure changes, or use of automatically closing thief hatches.

The commenter (2403-PAO) states that these requirements would be impractical as hatches are accessed to gauge tanks and conduct routine maintenance and repair. The commenter also states it would be difficult to monitor tanks that have low pressures. Additionally, the commenter is not aware where such equipment has been installed and operated successfully and requests that until such technology has been adequately designed, tested, and the costs and results are known, EPA should not finalize this requirement.

Commenter (2227-WEA) believes that it is not reasonable to include provisions in the regulations which require storage tank thief hatches to be equipped with preventive automated features such as alarms, pressure change monitors, or automatically closing thief hatches, because installing such automated features are not always feasible due to economic or technical limitations. In some circumstances the cost of equipment and labor can be too high for the benefit that would be seen for the resulting additional reduction in emissions, according to the commenter. The commenter believes that there are already preventative steps in place that focus

on maximizing the proper operation of thief hatches, including fugitive emissions programs, LDAR programs which identify leaking gaskets, and training for operations personnel. The commenter cautions that automated systems are also not always technologically feasible when power is necessary for actions at the storage tank and for communications that might be necessary to implement systems, especially in areas that bring challenges due to remoteness and geographical features. The commenter urges EPA not to finalize requirements for equipping storage tank thief hatches with automated features and instead should defer to LDAR regulations, existing inspection programs and focused operator training programs.

Conversely, commenter (2433-EDF *et al.*) supports EPA's proposal to require that thief hatches be equipped with alarms, automated systems to monitor for pressure changes, or automatically closing thief hatches. The commenter explains that thief hatches act as pressure safety devices and, when operated properly, prevent emissions from escaping into the atmosphere, but thief hatches can open and unintentionally emit either through improper latching after routine operations (checking tank levels, etc.) or, as a result of a pressure build-up within the tank.<sup>38</sup> The commenter points out that open or malfunctioning thief hatches, if not closed or repaired promptly, can be responsible for large amounts of methane and VOC emissions.<sup>39</sup> The commenter is concerned that because storage tanks are often located in remote locations with operating teams moving in and out, unsealed thief hatches could remain open for long stretches of time, freely emitting harmful methane and VOCs into the atmosphere.<sup>40</sup> According to the commenter, this issue could be significantly improved by installing monitoring technology on this equipment. The commenter states that requiring operators to choose to install at least one type of mitigation technique is reasonable and cost-effective. Various developers of automation technology and equipment have made viable options for thief hatch monitoring available to industry operators, according to the commenter.<sup>41</sup> When taking into account the lost revenue associated with wasted gas lost through open thief hatches, installing monitoring systems may ultimately benefit operators financially while also preventing harmful emissions, the commenter

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<sup>38</sup> Vance Ray, Use wireless to monitor thief hatches, Control (July 18, 2019), <https://www.controlglobal.com/manage/asset-management/article/11301041/use-wireless-to-monitor-thief-hatches>; Teledyne FLIR, How Safe are Thief Hatches? (June 18, 2021), <https://www.flir.com/discover/instruments/gas-detection/how-safe-are-thief-hatches/>.

<sup>39</sup> See also, Rutherford et al., Closing the methane gap in US oil and gas and natural gas emissions inventories, 12 Nature Comms. (Aug. 5, 2021), <https://www.nature.com/articles/s41467-021-25017-4>; Marc Mansfield et al., Storage Tank Emissions Pilot Project (STEPP): Fugitive Organic Compound Emissions from Liquid Storage Tanks in the Uinta Basin (July 17, 2017), <https://documents.deq.utah.gov/air-quality/planning/technical-analysis/DAQ-2017-009061.pdf>; Lesley Fleischman et al., Clean Air Task Force, Tank Emissions from Controlled Tanks, [https://www.epa.gov/sites/default/files/2017-11/documents/5\\_catf\\_tank\\_presentation\\_for\\_inventory\\_workshop\\_final.pdf](https://www.epa.gov/sites/default/files/2017-11/documents/5_catf_tank_presentation_for_inventory_workshop_final.pdf) (last accessed Feb. 10, 2023).

<sup>40</sup> See Jeff Jones, Thief Hatch Monitoring for Storage Tank Emissions, Fugitive Emissions Journal (June 2020), <https://www.emerson.com/documents/automation/article-thief-hatch-monitoring-for-storage-tank-emissionstopworx-en-6867874.pdf>.

<sup>41</sup> See, e.g., OleumTech, Thief Hatch Monitoring: Simple and Cost-effective Solution for Minimizing Emissions Risk, <https://oleumtech.com/news-and-blogs/2021/02/thief-hatch-monitoring-solution-for-minimizing-emissions-risk> (last visited Feb. 10, 2023); Scott Keller, SignalFire Introduces Tilt Scout – the "Hatch Watchdog" Wireless Thief Hatch Sensor for Remote Thief Hatch Monitoring, SignalFire, <https://www.signal-fire.com/signalfire-introduceshatch-watchdog-wireless-thief-hatch-sensor-remote-tank-monitoring/> (last visited Feb. 10, 2023).

believes<sup>42</sup> and will be an important step for EPA in promulgating effective, economical standards for these sources.

Response II-13-57: The EPA did request comment on thief hatch monitoring or alarm systems, recognizing the utility of such systems to reduce emissions from thief hatches and storage vessels generally. However, the EPA did not receive the type and scope of data and information in response to our request for comment that would be necessary to finalize any requirements in this respect. EPA reviewed the material referenced by footnote in the comment submitted. The report from the South Coast Air Quality Management District (SCAQMD)<sup>43</sup> provided some information but was insufficient for EPA to adopt without first submitting such a concept in proposal in notice and comment rulemaking. Specifically, the assumptions made in the SCAMD were not necessarily the same costs and assumptions EPA would need to make for a nation-wide rulemaking. We would also point out that the super-emitter program is anticipated to increase the level of vigilance that sources will need to address the events from storage vessels that could be observed and flagged for investigation. To that end, sources may find it prudent and cost effective to adopt such systems as a means to reduce the likelihood that a thief hatch could open and cause a super-emitter event that could be observed.

Comment: Commenter (2458-MiQ) recommends that because downstream emissions controls, like VRUs, are not an effective control for open thief hatches, specific regulation should be considered for thief hatches and other vent sources that are not routed directly into VRUs.

Response II-13-58: EPA did request comment on such systems, recognizing the utility of such systems to reduce emissions from thief hatches and storage vessels generally. However, the EPA did not receive the type and scope of data and information in response to our request for comment that would be necessary to finalize any requirements in this respect. See our response to comment II-13-56.

Comment: Commenters (2333-LongPath Technologies, Inc. (Longpath), 2440-Nevada Nanotech Systems, Inc. (NNS)) believe that storage vessels are excellent applications for continuous monitoring, especially thief hatches which represent one of the most problematic sources of emissions in the industry. The commenter (2440-NNS) suggests that continuous monitoring solutions such as “CP-CMS” systems provide immediate notification of emissions to operators, allowing rapid remediation of the emissions. For existing applications, the commenter states that these solutions can provide continuous methane detection for less than \$300 per year and five tank batteries can be monitored for less than \$900 per year. The commenter also encourages the EPA to also allow continuous monitoring technology solutions as a BSER for tanks and tank

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<sup>42</sup> See, e.g., Jeff Voorhis, Best Practices for Vapor Recovery Systems to Reduce Venting and Flaring at 4, <https://www.epa.gov/sites/default/files/2016-04/documents/8voorhis.pdf> (positing that when subtracting the estimated cost of wasted gas from estimated project costs, industry operators would ultimately experience a net gain.); Ray, supra note 538 (One company’s costs for installing monitoring technology on an 8-tank battery totals \$8,300).

<sup>43</sup> SCAQMD; Preliminary Draft Staff Report. Proposed Amended Rule 1178 – Further Reductions of VOC Emissions from Storage Tanks at Petroleum Facilities; and Proposed Amended Rule 463 – Organic Liquid Storage. February 2023. (See Docket EPA-HQ-OAR-2021-0317).

batteries to minimize methane emissions and states that continuous monitoring for methane emissions is especially important for NSPS OOOOb (existing) applications.

Commenter (2333-LongPath) notes that they have systems which correctly alarms operators to the presence of emissions from open thief hatches and deteriorated seals and believe that any requirements to equip thief hatches with alarms or other automated systems should also allow the use of continuous emissions monitoring systems with valid quantification. The commenter believes that this will incentivize operators to use this more comprehensive form of coverage, which reliably detects and quantifies this emission source category.

Response II-13-59: The EPA did request comment on such systems, recognizing the utility of such systems to reduce emissions from thief hatches and storage vessels generally. However, the EPA did not receive the type and scope of data and information in response to our request for comment that would be necessary to finalize any requirements in this respect. See response II-13-56 of this Chapter.

Comment: Commenter (2362-Environmental Integrity Project (EIP) *et al.*) questions why EPA limits flaring for oil wells but not for storage vessels. The commenter states that EPA has not rationally explained (or explained at all) why it is not requiring storage vessel facilities to minimize flaring and use of other controls. The commenter states that EPA's differing treatment of oil wells and tank batteries regarding the use of controls and flaring is arbitrary and capricious.<sup>44</sup> The commenter believes that requiring storage vessel facilities to minimize their use of flares and other combustion devices is important because these facilities can emit very large amounts of VOCs and methane through their flares and other control devices in situations such as when downstream processing facilities are shut down for repair or other reasons. The commenter provides an exhibit which they say identifies the total annual sulfur dioxide emissions released by ten oil and gas sources between 2015 and 2019 during various emission events that range from an average of several hundred to more than a thousand hours per year. Emissions of VOC's or methane from other facilities can also be very high, according to the commenter. The commenter believes there are available, cost-effective options to reduce the use of flares and other control devices at tank batteries. By way of example, the commenter believes that EPA could require storage vessel facilities to minimize flaring and use of other controls by recycling excess gas, which will likely require compressors to hold the gas until it can be fed back into downstream processing units. These compressors could be required at the tank batteries themselves or at the downstream processing units, explains the commenter.

The commenter (2362-EIP *et al.*) believes it is "appropriate" under CAA section 111(b)(1)(B), 42 U.S.C. section 7411(b)(1)(B), to strengthen the NSPS (and EG) for tank batteries to reduce flaring and use of other controls in these ways. Further, these improvements constitute the "degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) . . . has been adequately demonstrated" under CAA section 111(a)(1), *id.* section 7411(a)(1), according to the commenter.

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<sup>44</sup> See *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996) ("A long line of precedent has established that an agency action is arbitrary when the agency offered insufficient reasons for treating similar situations differently.").



At a minimum, the commenter states that EPA must strengthen the proposed standards and EG by requiring tank batteries with flares to develop flare management plans designed to minimize flaring and promote flare gas recovery, as EPA has required for refineries. The NSPS for refineries require owners and operators of flares to develop, implement, submit, and comply with a flare management plan that includes several detailed categories of information, including: a listing of units and systems connected to the flares; descriptions of the flares; an assessment of whether discharges to the flares can be minimized; and procedures to minimize or eliminate discharges to the flares during planned startup and shutdown of the units and systems connected to the flares, explains the commenter.

Similarly, states the commenter (2362-EIP *et al.*), although tied to certain unlawful loopholes (according to the commenter) for periods when flares operate above “smokeless capacity,” the NESHAP for refineries require owners and operators of flares that have the potential to operate above their smokeless capacity to develop, implement, submit, and comply with a flare management plan to minimize flaring during periods of startup, shutdown, or emergency releases. The commenter states that EPA has not rationally explained (or explained at all) why flare management plans should not be required here and that requiring refineries but not oil and gas tank batteries to develop and implement flare management plans would render EPA’s final rule arbitrary and capricious.

Response II-13-60: The standards for associated gas (gas from the first stage of separation during production) and for storage vessels differ because their BSER differ. While the BSER for associated gas is routing the gas to a sales line, section 60.5377b(a), the EPA has identified combustion (flaring) as the BSER for storage vessels affected facilities since the promulgation of the NSPS OOOO standards in 2012, and that continues to be the same in NSPS OOOOa and now OOOOb/OOOOC. The commenter has not claimed that our BSER analysis was flawed, or that any other control qualifies as the BSER for storage vessels. We further note that the standard is an emission limit and does not require flaring, and the EPA has expressly identified non-flaring options for meeting the standard, such as routing to a vapor recovery systems or a process.

EPA disagrees that flare management plans are necessary in the context of upstream oil and gas facilities. While flare management plans clearly enhance the effectiveness of flaring in the refinery setting, EPA disagrees that such an approach is necessary in this NSPS. EPA does not agree that a flare management plan would be reasonable for many affected facilities that constitute one flare, where assisted flares are less in use, and where the level of flaring is less overall. Moreover, EPA is finalizing a number of additional requirements with respect to flaring that will increase control effectiveness, such as additional monitoring of flaring operations.

Comment: Commenter (2428-API) believes that the requirement to manifold the vapor space of each storage vessel in the tank battery is unnecessary and restricts an operator’s flexibility in achieving compliance with the required 95 percent emissions reduction. The commenter states that an operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems

so that each control device is properly sized for the expected vent gas flow rate.<sup>45</sup> The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer, according to the commenter. To address this issue, the commenter offers the following redline to the regulatory text at 40 CFR 60.5395b(b) (suggested deletions are shown in strike-through):

Control requirements.

(1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;~~

~~(iii)~~(ii) The tank battery must be equipped with a one or more closed vent systems that meets the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraphs (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

Response II-13-61: EPA agrees with the commenter that it is not necessary to specify that the vapor spaces of the tanks within a tank battery be manifolded for control purposes, because the control criteria of a cover, closed vent system, and control device provide sufficient regulatory certainty that each tank in a storage vessel affected facility must be controlled to 95 percent.

On the issue of whether all tanks should be routed to a single control device, EPA does not interpret “a control device” as “a single control device” for the purpose of controlling a tank battery. By maintaining the text as “a control device” an operator can use redundant or multiple control devices within a single tank battery and still meet the requirements of the standard, because the collection of tanks in a tank battery manifolded by liquid line is an affected facility (where the potential for VOC and methane emissions is met) and each tank in the storage vessel

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<sup>45</sup> If not corrected, EPA’s failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983).

affected facility must be controlled to 95 percent, when the battery as a whole must be controlled to 95 percent.

Comment: Commenter (2428-API) states that EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel. The commenter explains that with the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa - until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. The commenter believes that this longer period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. Similar to comments the commenter provided with respect to control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, the commenter recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. The commenter states that such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, the commenter offers the following recommended redlines to the control requirements in §60.5395b(b) (suggested additions are underlined; suggested deletions are shown in strike-through):

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~(iii)<sup>46</sup> of this section.

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(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

Response II-13-62: The EPA disagrees with the commenters that an exemption from controlling emissions from storage vessels is needed when supplemental fuel is required. All flares or combustors will require supplemental fuel, either by natural gas or propane, for use for pilot gas and for sweep or purge gas. While we assumed most facilities would have natural gas available, propane can also be used. We therefore do not consider control to be technically infeasible when it would require supplemental fuels.

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<sup>46</sup> This citation includes other redlines suggested by the commenter regarding the requirement to manifold the vapor lines of storage vessels which are part of a tank battery.

Comment: Commenter (2383-Baker Hughes) agrees that open thief hatches and deteriorated seals around tank openings are significant emissions sources at tank batteries. The commenter believes that EPA is right to solicit comment on including a requirement to equip thief hatches with alarms, automated systems to monitor for pressure changes, or use of automatically closing thief hatches. The commenter supports such a requirement but notes that operators have traditionally been hesitant to deploy electronic monitoring equipment near thief hatches due to the risk associated with electrified sensing technologies in potentially flammable atmospheres that can be present at the thief hatch. A lower cost, less risky and more long-term abatement solution should be physical replacement of the thief hatch with a device that allows for capture of the emissions associated with pressure venting at the thief hatch port, according to the commenter. According to the commenter, there are technologies in late-stage development that will achieve significant reductions in storage vessel emissions associated with thief hatches. By way of example the commenter states that a thief hatch elimination device will eliminate the vent to atmosphere from thief hatches and would retrofit on to existing storage tanks and replace thief hatches on new storage tanks. The commenter states it would eliminate nearly 100 percent of the emissions resulting from thief hatches as it provides a pipe-away configuration to a vapor recovery system while still providing access to the tank contents for gauging and sampling purposes and has the added benefit of protecting the worker from being exposed to flammable atmosphere at the thief hatch port as well as toxic vapors from the storage tank head space. The commenter recommends that EPA include in both 40 CFR 60.5395b and 60.5396c allowance for solutions that eliminate or replace the thief hatch and provide a means of capturing emissions from thief hatch ports due to over pressure venting by piping those emissions to a flare or sales line.

Response II-13-63: EPA agrees with the comment with respect to the need for additional technology to address thief hatch emissions and is encouraged by the technology that is under development. The NSPS does not preclude the development and use of such technologies. EPA has attempted to address thief hatch emissions by other means, through revising the method to determine affected facility status for storage vessels, and the alternative technology component of the fugitive program, and the super-emitter program. With the commenter, EPA encourages further development of technology to address sources of emissions such as thief hatches.

### **13.4 Miscellaneous Other Storage Vessel-Related Comments**

Comment: Commenters (2326-AXPC, 2399-GPA) request that EPA extend the implementation deadlines; particularly for sources which become NSPS OOOOb affected facilities between proposal and promulgation. Commenter (2326-AXPC) explains that until NSPS OOOOb is a final rule, those storage vessels that commenced construction, modification, or reconstruction after November 15, 2021 (“NSPS OOOOa/b Vessels”), are subject to NSPS OOOOa, which has a different applicability threshold than NSPS OOOOb. The commenter explains that this switch to a storage tank battery approach effectively reduces the storage vessel affected source threshold, meaning the same storage may not be an NSPS OOOOa affected facility but will be an NSPS OOOOb affected facility if the applicability criteria remain the same in the final NSPS OOOOb. For these storage vessels, the commenter is concerned that a new suite of new requirements will become applicable 60 days after publication of the final rule, but operators will require more than 60 days’ time to implement these requirements. The commenter provides by

way of example, that certifying the design of each storage vessel closed vent system could take weeks, and operators will need to hire staff to implement control device monitoring requirements. Additionally, the commenter states, the proposed control device monitoring requirements require extensive capital investment in equipment that is likely to be in short supply (e.g., calorimeters). The commenter anticipates that EPA may argue that operators are on notice of the requirements, but notes that the rule is not final and may change in its final form and therefore it is inappropriate and poor policy for EPA to require operators to undertake significant capital investment and personnel hiring for a rule that is not, and may never become, final simply to be in position to comply suddenly with requirements that may be materially different in the final rule. The commenter reminds EPA that similar issues were encountered for storage vessels under NSPS OOOO, and in that rulemaking, EPA recognized the infeasibility of compliance for storage vessels constructed following proposal and before publication of the final rule and provided an additional year for those storage vessels to comply. Alternatively, the commenter requests that if EPA is unwilling to provide extended initial compliance deadlines as requested, that EPA provide extensions where good cause exists, as it did under the recently promulgated Uintah and Ouray Indian Reservation Federal Implementation Plan (FIP) for oil and natural gas sources.

Commenter (2399-GPA) states that the December 2022 Supplemental Proposal added monitoring requirements for storage vessel control devices that were not included in the November 2021 Proposal, as the November 2021 Proposal only provided general concepts for monitoring, recordkeeping, and reporting requirements but did not propose anything specific. The commenter explains that unlike large, capital-intensive equipment, storage vessels can be put into operation quickly and that in fact, a significant number of new storage tanks have been operating since EPA published the November 2021 Proposal. The commenter points out that these storage vessels are currently operating without the newly proposed monitoring requirements, and if application of the monitoring requirements were to relate back to the November 2021 Proposal, these sources would need to be retrofitted for compliance equivalent to an existing source as the equipment necessary for compliance with the new monitoring requirements could not have been incorporated into their initial design. Therefore, the commenter requests that any date for storage vessel compliance be at least one year after the effective date of any final rule as this time is needed to determine what type of monitoring devices could be used for each specific application and budget for the additional equipment purchasing and installation. Given the large number of storage vessels used in the midstream industry the commenter states, retrofitting will take a significant amount of time and resources.

Response II-13-64: The commenter seems to imply that the 1-year phase-in 2012 was to allow sources to allow sources time to see what the final rule requires and then begin to plan for compliance. That is incorrect. The prior phase-in was to address the concern at the time about not having enough control systems for the number of tanks that would need control. 77 FR 49525-6 (2012).

The commenters appear to be concerned with the potential change in status or operating requirements for storage vessels that were constructed, reconstructed or modified after the 2021 proposal and prior to the 2022 supplemental proposal. The EPA clarifies that OOOOb applies to storage vessel tank batteries that are new or modified after the date of the supplemental proposal,

December 6, 2022 (87 FR 74702). Therefore, storage vessels that commenced construction, modification, or reconstruction after November 15, 2021, and before December 6, 2022, continue to be subject NSPS OOOOa and not OOOOb. There is no change in affected facility status for these storage vessels. See the preamble section IX.A for a discussion of the dates when new requirements apply.

Comment: Commenter (2296-NMED) requests that EPA provide sufficient time for owners and operators to comply with the control requirements as part of a phased compliance timeline. The commenter explained that during the NMED Part 50 rulemaking hearing, affected owners and operators and industry stakeholders raised concerns about having sufficient numbers of control devices available to implement controls simultaneously. To address this, the commenter states that NMED Part 50 imposes a phased compliance deadline in order to ensure there are sufficient control devices available over the course of the compliance timeline.

Response II-13-65: The EPA disagrees with the comment that additional time is required for facilities to meet the requirements of the final rule. The proposed rule of November 15, 2021 (86 FR 63110) gave sources sufficient notice that additional requirements could require additional control systems. Furthermore, the EPA has determined that the effective date for implementation of the final rule will be determined based on the supplemental proposal, December 6, 2022 (87 FR 74702). Given these two factors, the EPA considers the final effective dates and compliance dates as sufficient to achieve compliances.

Comment: Commenter (3846-GPA) presented an example to illustrate an issue they identified regarding initial compliance demonstrations for storage vessel affected facilities. The commenter provides the following example:

A tank battery is controlled by a tank vapor recovery unit (VRU) with LPE limits and emissions over 6 tpy, so the tank battery is a storage vessel affected facility. According to the standards, the owner or operator is required to install a control device and is subject to **“60.5412b What additional requirements must I meet for determining initial compliance of my control device?”** It appears that §60.5412b(a)(2) would be the section for VRU controls, but that section then references testing procedure requirements in 60.5413b and there doesn’t appear to be any testing procedures in 60.5413b that apply to tank VRUs.

The commenter questions whether the rule considers tank VRUs to be control devices and if so, how do they comply with performance testing requirements? If not, the commenter is concerned that this could inadvertently require sites with tank VRUs to unnecessarily install a combustor to comply with the rule.

The commenter also noted a potential oversight at 40 CFR §60.5365b(e)(5). The commenter believes this cite should include methane in addition to VOC for sites without LPE limits. Without it, the commenter believes that no tanks under the prescribed circumstance would qualify for the exemption.

Response II-13-66: A storage vessel affected facility is subject to the control requirements of 40

CFR §60.5395b. 40 CFR §60.5395b(b) specifies that if the owner or operator uses a control device to reduce emissions from the storage vessel affected facility, it must meet the cover and closed vent system requirements. 40 CFR 60.5395b(b) also allows that emissions may be routed to a process, as an alternative to routing emissions to a control device, but the same cover and closed vent system requirements apply. As explained in the September 23, 2013, final rule<sup>47</sup> EPA previously clarified<sup>48</sup> that VRUs which route recovered gas and vapor back to the process are not control devices. Emissions which are routed to a process are not subject to control device performance testing procedures. To clarify that the performance test requirements of 40 CFR §60.5413b do not apply to emissions routed to a process, EPA has amended the initial compliance requirements at 40 CFR §60.5410b(j) to specify the initial compliance requirements when routing to a process (and which do not include a performance test).

The EPA notes that if the VRU is required as part of a legally and practicably enforceable permit limitation (as described in the example above), there may be requirements in the permit which apply.

Regarding the addition of “or methane” to 40 CFR §60.5365b(e)(5), the EPA agrees and has made that change.

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<sup>47</sup> See 78 FR 58241.

<sup>48</sup> Letter from Peter Tsirigotis to Matthew Todd, American Petroleum Institute. September 28, 2012. Docket Item No. EPA-HQ-OAR-2010-0505-4595.

## Chapter 14. Super Emitter Program

In the December 2022 supplemental proposal, this program was proposed under the name Super-Emitter Response Program (SERP), in the final rule, this program has been rebranded as the Super-Emitter Program. The responses in this chapter will address this program, as the Super-Emitter Program or as “the program”.

### 14.1 General Support and Opposition

Comment: Commenters (2212-On behalf of the Union of Concerned Scientists, 2296-New Mexico Environment Department (NMED), 2360-Devon Energy (Devon), 2392-Earthjustice et al., 2408-Colorado Local Government Coalition, 2410-California Office of the Attorney General et al., 2414-Carbon Mapper and RMI, 2442-Wyoming Coalition of Local Governments, 2453-Carbon Mapper and RMI, 2626-Kayrros, 2627-British Columbia Investment Management Corp. (BCI), 3389-First Focus on Children) broadly support EPA’s proposed SERP aimed at addressing large emission events from oil and gas facilities that significantly harm nearby communities. This innovative, first-of-a-kind initiative will combine third-party observations and direct operator notification of super emitter events with requirements for operators to conduct follow-up assessment and repair action.

Response II-14-1: EPA acknowledges the commenters support.

Comment: Commenters (2296-NMED, 2414-Carbon Mapper and RMI, 2627-BCI) support the Proposed Rule to prevent, detect and mitigate super emitter emissions events, which are some of the largest and most difficult to identify and fix. Methane leaks have significant consequences on the mix of greenhouse gases in the atmosphere, and its warming potential.

Commenter (2414-Carbon Mapper and RMI) adds the SERP can also identify potential issues with self-reported methane leakage with implications for EPA’s Methane Emission Reduction Program introduced in the Inflation Reduction Act (IRA). Similarly, the SERP will have the ability to flag gaps in EPA’s Greenhouse Gas Reporting Program (GHGRP), particularly for intermittent super emitters that often go undetected by traditional site-level monitoring, enabling improvements in overall methane accounting. While the SERP as proposed is limited to the onshore oil and gas production equipment included in the scope of this rule, it establishes a framework that encourages the use of persistent wide-area, high-resolution methane monitoring by satellites and other remote methods. One benefit of such systems is the ability to precisely geolocate methane point source emissions at adjacent infrastructure such as gathering pipelines, downstream natural gas operations, landfills etc, thus reducing the potential for misattribution to oil and gas producers. Another benefit, particularly for satellites capable of detecting methane over the ocean, is the ability to detect leaks and malfunctioning equipment at coastal processing and export facilities and offshore oil and gas platforms - thus offering more complete methane intensity verification of the US natural gas value chain with implications on US competitiveness in global markets. SERP-enabled precise location, quantification and transparent reporting of methane super emitters will offer significant climate benefits and additional co-benefits, such as



enabling improved assessment and communication of local impacts (both for operators and nearby communities) resulting from potential co-emitted pollutants such as VOCs and other health-harming air pollutants. Finally, the SERP will contribute to improved public confidence in mitigation progress by industry and government.

Commenter (2296-NMED) states the proposed rules are likely to affect thousands of sources in New Mexico. Effective, efficient and innovative compliance and enforcement strategies will improve overall rates of compliance, reduce harmful air pollution, and improve overall air quality and impacts on public health and the environment. Strategies could include the preparation and submittal of annual compliance certifications identifying specific areas of compliance and noncompliance with rule provisions and third-party audits of an operator's compliance with the rule, including the effectiveness of the operator's LDAR program.

Response II-14-2: EPA acknowledges the commenter's support and suggestions.

Comment: Commenters (2409-BP America Inc., 2446-Independent Petroleum Association of America (IPAA)) encourage the safe, accurate, and rapid identification and mitigation of large methane emissions events. If there are reliable, high-quality data indicating a significant methane leak at their facility, the commenters want to know about it. The commenters therefore support EPA's effort to design a SERP, so long as EPA (or a state with delegated authority) maintains a meaningful oversight role, ensures data quality and reliability, and retains discretion and accountability relating to compliance and enforcement.<sup>1</sup>

Commenter (2409-BP America Inc.) appreciates the effort by EPA to consider and incorporate feedback on the November 2021 proposed community monitoring program to inform the currently proposed SERP. The commenter is encouraged that EPA appears to have begun addressing feedback on critical issues including: the role EPA should play in a third-party program; the importance of safety and minimizing incentives for untrained, non-industry personnel to be out in the field; and incorporating operational and technical requirements for validated third parties. The commenter urges EPA to revise the program so that it: (1) reconceptualizes the respective role of third-party monitors and EPA, so that EPA retains its oversight authority; (2) incentivizes operators to respond to validated third-party notifications by encouraging responsiveness and protecting corrective actions; and (3) fosters accountability and transparency from all parties involved.

Response II-14-3: EPA acknowledges the commenters' support and suggestions. EPA has revised the final rule to include EPA in a central role for approving technology used and certifying the third parties participating in the program. EPA has revised the final rule to require the third party to submit super-emitter data to the EPA and then EPA will review this data before providing the notification to the owner or operator.

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<sup>1</sup> In its proposal for reviewing third-party monitoring and detection technologies, EPA recognizes the importance of ensuring that "data quality objectives" are met. 87 Fed. Reg. at 74746. EPA should apply that same principle in reviewing and validating third-party monitoring data before that data is publicly reported. EPA should define its "data quality objectives," be transparent in how it plans to implement.

Comment: Commenter (2389-American Chemistry Council (ACC)) states it is critical that new monitoring programs and associated requirements are well-supported with clear and definite environmental benefits. As proposed, it is unclear if EPA has identified an adequate basis of environmental benefits sufficient to support a program of this sweeping and precedential nature. In the proposal, EPA notes that the program's objective is to "provide a comprehensive and effective remedy for large emission events that disproportionately contribute to methane emissions from the Crude Oil and Natural Gas source category" and may potentially impact nearby communities. EPA proposes this program as a backstop to help monitor and respond to these types of emissions events while avoiding additional significant and unnecessary inspection costs.

While this overall goal is commendable, Commenter (2389-ACC) is concerned that the environmental benefit of the EPA's super emitter program as proposed is not well-defined, resulting in a program that could carry significantly onerous implications with minimal actual benefits. EPA itself acknowledges this reality and states that it is "not currently able to quantify the emissions reductions likely to result from preventing or more quickly mitigating super emitter emissions."<sup>2</sup> Despite this, the proposed program would result in the creation of serious regulatory obligations for facility owners and operators that may or may not result in any emissions reductions. Given the important nature of such a new program, the commenter believes that the Agency should provide a more accurate and detailed description of the precise environmental benefits to support it.

Response II-14-4: EPA acknowledges the commenters' support and suggestions. The super-emitter program is designed to provide actionable (*i.e.*, EPA verified) data of a super-emitter event that would trigger a response by an owner or operator. There are no additional obligations for owner or operators than the required investigations into the potential cause of a large emission event as detailed in Section X.C and XI.C of the preamble of the final rule. Any other requirements on an owner or operator to either repair the cause(s) of the emissions, are already required by the applicable regulations.

Comment: Commenters (2177-Ute Indian Tribe, 2202-Texas Oil and Gas Association (TXOGA), 2218-Texas Commission on Environmental Quality (TCEQ), 2399-GPA Midstream Association) argue the proposed super emitter program is overly burdensome for states and should be removed from the final rule.

Commenter (2177-Ute Indian Tribe) argues due to the greatly varying technologies currently available that could theoretically detect a super emitter event, there is too much uncertainty for this to be a regulatory requirement. Operators should address any potential leaks that are brought to their attention on a timely basis (which they will likely do anyway as there is an economic incentive to keeping gas in the pipelines).

Commenter (2177-Ute Indian Tribe) states due to the in-ability of EPA to regulate the accuracy of remote-sensing aircraft, mobile monitoring platforms, or satellites to identify super emitter

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<sup>2</sup> 87 FR 74747.

emissions events, this should not be a regulated program. These provide useful information that can be passed along to operators, but their response should not be regulated in this way.

Response II-14-5: EPA acknowledges the commenters' support and suggestions. EPA disagrees the program is burdensome on the states and the design of the program in the final rule put the responsibilities on the EPA to certify the third parties and the underlying technology used in this program. These steps have been put in place in the final rule to assure the accuracy of the super-emitter data being provided to the owner or operator to aid in their follow-up investigations.

Comment: Commenters (2283-Endeavor Energy Resources, 2301-U.S. Chamber of Commerce, 2366-Berkshire Hathaway Energy Corporation (BHE)) recommend that EPA remove this proposed program in its entirety from any final rule or defer action on this program to avoid unnecessary violations of law that would risk the durability of the Methane Proposal more broadly. As proposed, the provisions to ensure third-party notices are credible are inadequate and risk distracting or detracting from addressing real or more pressing environmental, health, and safety concerns without providing an environmental benefit. As currently proposed, the program would also force operators to spend significant resources on defending against even erroneous reports, including reports identifying the wrong operator or misidentifying compliant emissions events as unlawful). According to the commenters, their suggested revisions would not suffice to make the proposed program lawful and workable, although they would at least mitigate some problematic aspects of the program.

Commenter (2202-TXOGA) believes that, in order to provide the regulated community adequate notice of the proposed parameters of the Super emitter Program, EPA should initiate a separate rulemaking, backed by additional analysis, and propose anew a program, the elements of which, to include its legal basis, specific form, and likely effectiveness, are more clearly identified at the outset. The commenter believes that EPA's current approach is likely to lead to problems of "logical outgrowth" whatever form the final rule may take.

Response II-14-6: EPA acknowledges the commenters' support and suggestions. EPA has revised the final rule to better address expectations regarding investigations conducted by the owner or operators when they receive a super-emitter notification as detailed in Section X.C.2 and XI.C.4 of the preamble of the final rule. EPA considers these investigations to be necessary and appropriate for identifying if a super-emitter emissions event has happened or are ongoing.

## **14.2 Definition Changes**

### ***14.2.1 Super-Emitter Definition***

Comment: Commenter (2202-TXOGA) states rather like Schrödinger's cat, a "super-emitter" affected facility (or designated facility) would spring into existence only when someone (be it EPA, a delegated authority, or a private party) actually detects an ongoing "super emitter event" (i.e., ongoing emissions beyond the 100 kg/hr threshold) and then informs the relevant owner/operator of the existence of that ongoing event. Until this point in time, the facility is not an "affected facility." Thus, the actions of private, third-party notifiers would not only compel an

owner/operator to take action, but such action would also operate to “create” the “super emitter affected facility” (or designated facility) when it could not be said to exist prior to notification being made. Assuming that Clean Air Act (CAA) Section 111 does authorize defining “affected facility” and “designated facility” on the basis of contingent events, in the situation where private, third-party actors are left responsible for triggering the regulatory response in the first instance, it is that much more important to establish that the CAA grants authority to adopt such a program.

Response II-14-7: EPA acknowledges the commenters’ suggestions; the final rule no longer includes a super-emitter affected facility definition. The final rule would require owner or operators to determine whether the source of emissions could have been through equipment subject to either NSPS OOOO, OOOOa, OOOOb, or potentially, EG OOOOc.

Comment: Commenter (2258-Marcellus Shale Coalition (MSC)) objects to the usage of the term “super-emitter” as it sensationalizes these events and has been used to describe events of varying magnitudes from various different sources.

Response II-14-8: EPA disagrees that the term super-emitter is “sensationalism” and super-emitter is a defined term meaning a methane emission event with an emission rate of >100 kg/hr of methane which would trigger an investigation of the oil and natural gas facility (e.g., individual well site, centralized production facility, natural gas processing plant, or compressor station).

Comment: Commenter (2305-The Williams Companies, Inc.) have significant concerns by the EPA’s use of the term “super emitter.” The term can invoke incorrect conclusions about an owner, operator, or a facility for emissions activities likely already contemplated or accounted for in a facility’s existing air permit. EPA should consider aligning the term “super emitter” in this draft rule with “other large, release events” proposed in the draft Subpart W Rule to ensure consistency and avoid confusion and over-exaggeration of events that are the result of abnormal operations or equipment malfunction, and that typically occur on an intermittent basis.

Response II-14-9: EPA recognizes the commenters’ concern; however, we are maintaining the term super-emitter in the final rule. The term is defined a methane emission event with an emission rate of >100 kg/hr of methane which would trigger an investigation of a site. For that reason, it is essential that we have term that are different than what is used in other rulemakings (i.e., Subpart W) in order to distinguish what the required actions should be.

Comment: Commenters (2172-Kentucky Oil and Gas Association, 2354-Business Roundtable) state the Super emitter threshold is not well defined. EPA is proposing to apply the super emitter definition to a large emission event at an individual well site, centralized production facility, compressor station or natural gas processing plant. It is unclear if the threshold is for all combined emissions, specific emission unit or other grouping, so it will be difficult to determine what emissions would be considered under the super emitter definition and therefore who might be the responsible party. This raises additional complications regarding third-party notifications and whether notifications are valid.

Response II-14-10: The super-emitter term is assumed to be an aggregate site-level emission event given many of the remote detection technology expected to be applied to this program would not be able to identify component level emissions.

Comment: Commenter (2453-Carbon Mapper and RMI) states EPA should clarify the definition of “owner/operator” and “site” and specify the interval for evaluation when reviewing claims that “more than three notifications were made in error”. In one instance the proposed rule applies to “the same site” and in another “to that same owner or operator”. While more than three verifiable errors at a single production site in one month might be reasonable grounds for review, three errors across a population of hundreds of facilities over the course of a year would not be excessive considering statistical fluctuations inherent in a large number of samples.

Response II-14-11: The EPA has revised and better-defined criteria for when an owner or operator may petition the Administrator to remove a third-parties certification in the final rule, including the requirements where an owner or operator may petition the Administrator to remove a certification. An owner or operator may petition the Administrator after an owner or operator that has received more than three erroneous notices of a super-emitter event at the same well site, centralized production facility, or compressor station from the EPA that were submitted to the EPA by the same third party may petition.

EPA has also expanded the criteria for grounds on which a third-party certification could be removed to include a certified third-party notifier making material changes to their procedures for identifying super-emitter events without seeking recertification and when an the administrator finds that the certified third-party notifier has submitted data with significant errors (e.g., misidentification of the owner or operator) or if the third-party notifier has engaged in illegal activity during the during the assessment of a super-emitter event (e.g., trespassing).

Comment: Commenter (2172-Kentucky Oil and Gas Association) states EPA’s use of Tons, pounds, kilograms, per hour, per year is confusing and does not include a consistent basis used by the oil and gas industry. The commenter’s calculation concludes that 100 kg is approximately equal to 4.2 Mcf of pure methane.

Commenter (2172-Kentucky Oil and Gas Association) states a 4 Mcf in an hour release (100 kg/hr) trigger point could result in many reportable occurrences that are insignificant, not to mention very difficult to determine if such a small volume has been emitted. Super Emitter reporting would become an excessive burden for small operators who operate most of the small wells that when opened for maintenance could possibly emit 4 Mcf quickly but then drop to an undetectable flow. A small gas well that produces less than 10 Mcf/day, shut in prior to being opened for maintenance, might release 4 Mcf in its first few minutes. Further, the well probably would not vent 8 Mcf (200 kg) total during a 10-hour period it is open maintenance.

Commenter (2172-Kentucky Oil and Gas Association) states total Emissions from this type of event during what would be considered normal operations could qualify as a Super Emitter event requiring the operator to generate an unnecessary report that would include “root cause” and “corrective action” which would be known before the well is opened. The commenter does not

believe this type of event is what the EPA is trying to identify, nor asking third parties to help identify.

Commenter (2172-Kentucky Oil and Gas Association) recommends that the EPA modify the definition of Super Emitter and adopt a significantly longer period over which the emission is to occur before it is considered a Super Emitter. The type of event described above could be excluded by extending the time frame of the event, i.e., “averaging 4 Mcf/hour over a 4-hour period”, or an event that releases an excess of 100 Mcf to the atmosphere in a 24-hour period.

Response II-14-12: EPA acknowledges the commenters’ suggestions. EPA is maintaining the >100 kg/hr of methane detection criteria and it represents a threshold and not a total mass of emissions.

Regarding the commenters to concern that maintenance events may trigger a super-emitter response; EPA acknowledges these events could have been caused by maintenance events. The final rule is intended to provide additional information to an owner or operators when large emission events are identified to ensure the emission event has ended, in the case of a maintenance, those emissions should end upon completion of those maintenance events.

Comment: Commenter (2458-MiQ) the supplemental preamble states “Super emitter emissions events could also be from intentional venting as part of normal operations or maintenance. The proposed SERP discussed in this section is not intended to address these events.”<sup>3</sup> Given the ultimate intention of the SERP – to limit large-scale methane release events – the commenter recommends that EPA define emission events that are part of normal operations or maintenance, and place regulatory parameters on these event types. This recommendation is made so that this provision does not become a regulatory loophole whereby super emitter and intentional events become effectively interchangeable – thereby obviating the value of the SERP.

Response II-14-13: EPA recognizes the comment and agrees that a super-emitter event could be the result of an allowable emission. The goal of the Super Emitter Program is intended to inform an owner or operator when these large events occur, so an owner or operator could investigate and repair if necessary. Where the event is an allowable emission, the owner or operator would indicate that as part of the reporting requirement in the final rule and in the instances where those emission events were known process releases due to maintenance events.

Comment: Commenter (2428-American Petroleum Institute (API)) points to just a few months ago, when addressing essentially the same issue under Subpart W of the GHGRP, EPA proposed to establish a new reporting requirement for “other large release events,” which EPA proposed to define as “events that release at least 250 mtCO<sub>2</sub>e per event.”<sup>4</sup> In explaining its rationale for setting this threshold, EPA explains that, “[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent “malfunctioning” equipment, these

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<sup>3</sup> 87 Fed. Reg. 74747, fn 101.

<sup>4</sup> 87 Fed. Reg. 36920, 36982 (June 21, 2022)

sources are ubiquitous across the oil and gas sector [and] are generally small.”<sup>5</sup> The proposed 250 mt reporting threshold is intended to capture “large emissions events.”<sup>6</sup> EPA derived the value by assessing “other emissions sources that [it] considered large.”<sup>7</sup> The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares.<sup>8</sup>

Commenter (2428-API) continues, despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as “super-emitting” that EPA in the Subpart W proposal dismisses as “ubiquitous” and “generally small.”

Commenter (2428-API) argues the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of “super emitter” makes sense in light of the proposed rules for large event release reporting under Subpart W. Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of “super emitter” is of central relevance to the SERP and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

Response II-14-14: EPA acknowledges the commenters’ comments and suggestions, and EPA has chosen not to finalize the super-emitter affected facility under OOOOb and has redefined the program to better identify which sites would be subject to the rule. EPA acknowledges there are similarities in the GHG reporting rule and the NSPS rulemaking how these emission events are defined however the NSPS is distinctly different, as the goal of the Super Emitter Program is to provide information to an owner or operator as these emissions happen, so they may be remedied, if necessary.

Commenter (2326-American Exploration and Production Council (AXPC)) argues EPA’s proposed rule language lacks clarity regarding whether super-emitter events can only be identified at affected facilities covered by NSPS OOOOb (or upon adoption by the states, from designated facilities covered by EG OOOOc). In its preamble, the EPA makes numerous

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<sup>5</sup> Id.

<sup>6</sup> Id.

<sup>7</sup> Id.

<sup>8</sup> Id. at 36983.

statements that indicate it intends that super-emitter emissions events can come only from NSPS OOOOb/c sources, including:

- the EPA's conclusion that a super-emitter emissions event that requires mitigation is one "either due to a failure to comply with one of the standards in this rule or due to an upset or malfunction at a source covered by this rule."
- Owners and operators would have the opportunity to rebut information provided by the third party, including that "the emissions event did not occur at a regulated facility."
- "Where compliance is achieved with the applicable standards, the EPA does not expect unintentional releases at these very high levels to occur in normal operation."
- "Super-emitter emissions events could also be from intentional venting as part of normal operations or maintenance. The proposed super-emitter response program discussed in this section is not intended to address these events."
- "[T]he super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule."

Commenter (2326-AXPC) states, despite the language from the preambles, the EPA's draft proposed regulations do not specifically state that the super-emitter emission events only occur at NSPS OOOOb affected facilities (or designated facilities). Rather, the EPA simply defines a super-emitter emissions event to be any source of emissions over the threshold "located at an individual well site, centralized production facility, or compressor station." Nowhere does the EPA make clear that it must be located at one of those facility types that is subject to NSPS OOOOb and also associated with/emitted from an affected facility – an intent the preamble makes clear.<sup>17</sup> However, if the EPA does have the authority to adopt super-emitter emission events regulations in a performance standard, such requirements would need to be relevant to and only apply to NSPS OOOOb affected facilities.

Response II-14-15: Super-emitter events can originate from sources that are not affected/designated facilities under NSPS OOOOb and EG OOOOc. Accordingly, the final Super Emitter Program requires the owner/operator who has received an EPA notice of a super emitter event to conduct an investigation of an oil and natural gas facility which could be the cause of the super emitter event identified in the EPA notice, and whether or not such equipment is subject to regulation NSPS OOOO, OOOOa, OOOOb, or a state or Federal plan implementing EG OOOOc.

Therefore, Commenter (2326-AXPC) argues if the EPA retains the super-emitter emissions event affected facility, it must revise the definition of a super-emitter emissions event to refer to those emissions above the threshold and associated with an affected facility subject to NSPS OOOOb. Thus, if a third party provides notification of an event over 100 kg/hour of methane, then only those events associated with an NSPS OOOOb affected facility (e.g., if above the thresholds: an unlit flare or combustion device associated with an NSPS OOOOb affected tank battery facility, a malfunctioning natural gas pneumatic controller, etc.) could potentially constitute a super-emitter emissions event and require an operator's corrective action or recordkeeping under NSPS OOOOb. Revisions to reflect this intent would need to be made throughout the provisions.



Commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) state often under the CAA, the term "source" refers to the entirety of the stationary source. However, the use of the term source or emissions source throughout the super emitter provisions makes clear that EPA intends for the term source to mean specific equipment located at one of the specific types of stationary sources. In particular, it is clear EPA intended to apply the super emitter emissions event program to affected facilities as defined in NSPS OOOOb.

Response II-14-16: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. EPA's authority to regulate sources under CAA section 111 and its authority under CAA section 114(a) to require "any person who owns or operates any emission source" (except mobile sources) to provide information necessary for purposes of carrying out the CAA. EPA has revised the final rule as detailed in Section X.C and XI.C of the preamble of the final rule and has defined the responsibilities of the owner or operator to investigate large emissions from sites to determine if the causes are from equipment subject to from regulation under NSPS OOOO, OOOOa, OOOOb, or a state or Federal plan implementing EG OOOOc.

Comment: Commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) note EPA's rule defines a super emitter emissions event as "any source of emissions" located at an individual well site, centralized production facility, or compressor station, with emissions detected above a certain rate.

Commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) ask EPA to clarify that "source," as used in this section, refers to emissions above the threshold at any individual (e.g., storage vessel, pneumatic controller, etc.) affected facility. This clarification is important, because if there is no individual piece of equipment or activity emitting over 100 kg/hr, then it should not be considered a super emitter event - even if the methane concentrations from the entire source are greater than 100 kg/hr.

Response II-14-17: EPA is maintaining the definition of a super-emitter event from the December 2022 proposal and has clarified the responsibilities of the owner or operator to investigate large emissions from an identified oil and natural gas facility to determine if the causes are from equipment subject to from regulation under NSPS OOOO, OOOOa, OOOOb, or a state or Federal plan implementing EG OOOOc.

#### ***14.2.2 "Normal Operation"***

Comment: Commenter (2483-Interstate Natural Gas Association of America (INGAA)) notes as EPA acknowledges, normal operations and maintenance from intentional venting might exceed the proposed threshold of 100 kg/hr of methane.<sup>9</sup> Although EPA says the program "is not intended to address these events," owners and operators will nonetheless likely receive notices that stem from normal operations that will require at a minimum investigation and the filing of a

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<sup>9</sup> 87 Fed. Reg. at 74,747 n.101.

report “explaining ... that ... the emissions event was not the result of malfunctions or abnormal operation that could be mitigated.”<sup>10</sup> This is unduly burdensome.

Commenter (2483-INGAA) notes EPA has stated that it “does not expect unintentional releases at [the 100 kg/hr threshold level] to occur in normal operations” and says “the occurrence of an unintentional release at this emissions rate should be unusual...”<sup>11</sup> Unfortunately, the 100 kg/hr threshold is too low, and commenter members believe that the reporting of emissions from normal operations will not be an “unusual” occurrence. Typical operational releases will exceed the 100 kg/hr threshold in some cases. These intentional releases, which include blowdowns, are performed for important safety purposes. EPA should consider revising the program to take into account the difference between continuous leaks (which are problematic and should be addressed) and events-based emissions (such as venting emissions during normal operation and maintenance) that are permitted. In any event, any final rule must make clear that an intentional, permitted release cannot ever be considered a “super emitter event.”

Response II-14-18: EPA acknowledges the suggestions and revised the defined the owner or operators’ requirements for responding to super-emitter notifications in Section X.C.2 and XI.C.4 of the preamble of the final rule.

One of these investigations steps is to evaluate any maintenance events or operational events that had been conducted in the timeframe of the super-emitter event. The goal of this program is not to prevent allowable maintenance or operational events from being conducted, but to inform an owner or operator when these large events occur, so an owner or operator can investigate, correct, and repair if necessary. The goal of this program is not to prevent these maintenance or operational event from being conducted and only to make sure that they do not become persistent emissions in the event a close-out is not adequately performed.

Comment: Commenter (2306-Citizen's Climate Lobby, 2444-NAACP) argue “normal operations” should never involve emissions over 100 kg/hr, so the proposed rule should remove this framing in section (c)(8) except for emissions under 100 kg total.<sup>12</sup>

Commenter (2444-NAACP) states this would change the current language of “Documentation that emissions were the result of allowed venting of emissions as part of normal operations, including routine maintenance (if applicable)” to “Documentation that emissions under 100kg total were the result of allowed venting of emissions as part of normal operations, including routine maintenance (if applicable).” This change clarifies that corrections under this program do not constitute “compliance” to earn any exemptions from the methane charge for those excess emissions.

Commenter (2306-Citizen's Climate Lobby) recommends changing “...emissions were...” to “...emissions under 100 kg total were...” This also makes clear that corrections under this

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<sup>10</sup> Id. at 74,750.

<sup>11</sup> Id. at 74,749.

<sup>12</sup> Proposed Rule P.24 - 40 CFR 60.5371b(c)(8).

program do not constitute “compliance” to earn any exemptions from the methane charge for those excess emissions.

Comment: Commenter (2444-NAACP) argues “normal operations” should never involve emissions over 100 kg/hr, so the proposed rule should remove this framing in section (c)(8) except for emissions under 100 kg total.<sup>13</sup> This would change the current language of “Documentation that emissions were the result of allowed venting of emissions as part of normal operations, including routine maintenance (if applicable)” to “Documentation that emissions under 100 kg total were the result of allowed venting of emissions as part of normal operations, including routine maintenance (if applicable).” This change clarifies that corrections under this program do not constitute “compliance” to earn any exemptions from the methane charge for those excess emissions.

Response II-14-19: EPA acknowledges the commenters’ support and suggestions. However, EPA is aware that certain maintenance events could result in emission rates in excess of 100 kg/hr of methane, however these events are infrequent. EPA has structured the required investigation steps to determine the cause of these emissions, including identification of these infrequent maintenance events, and that they are not ongoing.

Note: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

### **14.3 Rationale for Proposed Program**

Comment: Commenter (2410-California Office of the Attorney General et al.) states as EPA notes, the SERP would largely require owners and operators to undertake actions already required by other standards and requirements of the proposed rule in order to mitigate super emitter emissions events; the SERP would merely require that these actions be taken sooner, rather than waiting until they are detected by periodic monitoring.<sup>14</sup>

Response II-14-20: EPA acknowledges the commenters’ support and agrees that beyond the requirement for investigations, the requirements to mitigate any found emissions are already included under either the NSPS OOOO, OOOOa, OOOOb, or a state or Federal plan implementing EG OOOOc.

Comment: Commenter (2249-National Association of Clean Air Agencies) states EPA’s efforts to create streamlined pathways for data to be actionable for these events is laudable. However, aspects of the proposal remain concerningly ambiguous and could render the proposed program unworkable, counterproductive, and/or superfluous. The SERP is a novel program without precedent, that lies outside the usual delegation of authority to state and local air agencies that

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<sup>13</sup> Proposed Rule P.24 - 40 CFR 60.5371b(c)(8).

<sup>14</sup> 87 Fed. Reg. at 74,753–54.

the CAA is built on. EPA should be more explicit in citing its specific authority to implement if it proceeds or make the program legally severable to protect the remainder of the methane proposal from court challenges. If EPA determines that it will not proceed with the SERP as proposed, there are many options available for EPA to leverage its own remote sensing and other detection programs. The IRA offers significant resources for satellite and other programs that EPA can use to detect super emitter events and situations. EPA may wish to augment its own detection programs with a focus on improved data accessibility and transparency, making information more readily and easily available for the public to access and understand, in ways that productively enable their engagement.

Commenter (2249-National Association of Clean Air Agencies) states if EPA chooses to proceed, numerous clarifications will be important prior to finalization. Although EPA has articulated that only applications leveraging remote sensing platforms are approvable, the supplemental proposal offers little clarity about the approvable sensing methods borne on these platforms. The proposal also offers little clarity about the necessary demonstrated expertise for third parties. Among other clarifications, EPA should be explicit that state and local clean air agencies can be presumed as qualifying; EPA should also offer a high level of clarity about other approved third parties. In addition, if EPA proceeds with this program, the agency should make transparent and publicly disclose what other qualified parties have been certified and provide more robustly considered and detailed description of how submitted data would be disclosed.

Response II-14-21: EPA acknowledges the commenters' input and in the final rule, we have provided additional structure in the rule explaining the qualifications of third parties and what these parties must submit to the EPA as part of the certification processes in Section X.C.2 and XI.C.2 of the preamble of the final rule. EPA has also revised the criteria for the which remote sensing technologies could be applied, including the approval of the technology used through the advanced methane technology program in the final rule.

Comment: Commenter (2249-National Association of Clean Air Agencies) adds EPA should consider whether its SERP in fact marshals the resources to address the largest, most concerning sources. EPA's supplemental proposal cites research that holds that the top five percent of sources account for over fifty percent of emissions (with results that vary by production basin), and that many of the provisions included in EPA's 2021 proposal and 2022 supplemental proposal would prevent most of these events (by requiring improved equipment and facility performance and by improving monitoring that can detect malfunctioning or improperly operated equipment.) EPA may wish to consider if the backstop program to augment these other provisions that would make more sense focuses on basin-wide detection and reporting, rather than specific equipment or facility reporting. Backstopping with detection and actionable reporting at the basin level, that would address multiple sources, would involve different detection methods, thresholds, and other parameters, but may serve as a more appropriate backstop that would trigger effective compliance assurance efforts by the appropriate agencies.

Commenter (2283-Endeavor Energy Resources) adds while EPA emphasizes the need for the SERP as an additional "backstop" due to the "significant impact[s]" of super emitter events and

the possibility that operator inspection programs may miss some such events,<sup>15</sup> the agency does not explain the need to supplement EPA's existing monitoring and oversight authority with private parties. Nor does EPA explain why private parties must also possess enforcement authority-in the sense that operators will be required to investigate and respond to a report super emitter event-to effectuate the stated goal of serving as a backstop in detecting and reporting potential super emitter events. The absence of an explanation to justify additional, borderline redundant monitoring is arbitrary and capricious.<sup>16</sup>

Response II-14-22: EPA recognizes the commenters' concern, with EPA in centralized role in the Super Emitter Program in the final rule, we have addressed the commenters oversight and enforcement authority concerns. EPA disagrees the Super Emitter Program is redundant monitoring and instead in complementary monitoring, and the program is intended to provide actionable (*i.e.*, EPA verified super-emitter event) information regarding a sites' emissions outside of an owner or operators typical monitoring frequency.

Comment: Commenter (2343-Institute for Policy Integrity at New York University School of Law) states while there are significant uncertainties related to predicting specific super emitter events, EPA should work to better quantify the net benefits of the SERP to the extent possible. While it is fully appropriate for EPA to consider the benefits of the SERP even if it is unable to fully quantify them,<sup>17</sup> EPA should consider whether it can provide a range of possible emissions reductions based upon the modeling information in Appendix D or other information. EPA should also consider performing a breakeven analysis to identify the minimum number of emissions reductions necessary to justify the program.<sup>18</sup> EPA should then explain why it believes the emissions reductions exceed the breakeven point.

Commenter (2343-Institute for Policy Integrity at New York University School of Law) states given that super emitter events have such large mass emissions rates (100 kg/hr or greater) and the SERP could decrease the length of these events significantly, its potential benefits stand to be quite large. Further, EPA estimates that the additional cost to regulated entities of a program that would merely require owners to perform a root-cause analysis and take corrective action if they are notified of a super emitter emissions event<sup>19</sup> stands to be quite small. EPA already

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<sup>15</sup> *Id.*

<sup>16</sup> See *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42-43 (1983).

<sup>17</sup> See Exec. Order No. 13,563 § 1, 76 Fed. Reg. 3821, 3821 (Jan. 18, 2011) (affirming Exec. Order No. 12,866); accord Exec. Order No. 12,866 § 1(a), 58 Fed. Reg. 51,735, 51,735 (Sept. 30, 1993) ("Costs and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider."). Circular A-4 (2003), which provides further guidance on conducting regulatory analysis from the Office of Management & Budget, further cautions agencies against ignoring the potential magnitude of direct unquantified benefits, because the most efficient alternative may not have the "largest quantified and monetized . . . estimate." Circular A-4 (2003), *supra* note 10; see also EPA, GUIDELINES FOR PREPARING ECONOMIC ANALYSIS 7-49 (2014), <https://perma.cc/9JZH-FKK5> [hereinafter EPA ECONOMIC ANALYSIS GUIDELINES].

<sup>18</sup> See Circular A-4 (2003), *supra* note 10, at 2 (instructing that if the agency determines that the non-quantified benefits or costs are important, agencies should carry out a threshold or break even analysis to evaluate their significance and to "indicate, where possible, which non-quantified effects are most important and why"); EPA ECONOMIC ANALYSIS GUIDELINES, *supra* note 37, at 7-50 (discussing the appropriateness of using break even analysis).

<sup>19</sup> Supplemental Proposal, *supra* note 2, at 74,712 tbl.3.

determined that there would be “no associated monitoring cost for owners and operators” because “owners and operators do not bear the cost of monitoring and detecting super emitter emissions events.”<sup>20</sup> EPA’s choice to not quantify the impacts of this program thus likely leads the agency to again undercount the net benefits of the Supplemental Proposal.

Response II-14-23: EPA acknowledges the commenters’ input and has removed the root cause and corrective action requirement in the final rule. EPA has designed the investigation criteria in the final rule to minimize time and effort in identifying these large emission events, as they should be relatively easy to distinguish if they are ongoing as opposed to a fugitive monitoring inspection designed to identify much smaller leaks.

#### **14.3.1 Studies Supporting SERP**

Comment: Commenter (2284-Kairos Aerospace) cites Cusworth et al. (2021) (“Cusworth”) and Chen et al. (2022) (“Chen”) as works cited by EPA that are major advancements in our understanding of the emission contribution and frequency of large emissions. The commenter agrees with EPA’s decision to cite and include these papers in its thought process for both the FEAST modeling work as well as the SERP.

Commenter (2284-Kairos Aerospace) acknowledges EPA’s efforts to reflect the latest peer-reviewed science on leak distributions within its modeling. Many historical studies that rely on bottom-up inventory measurements fail to account for super emitter events at all. As more recent studies have demonstrated<sup>21</sup>, super emitter events are rare but can dominate the total amount of methane being emitted at the basin scale. By incorporating these latest results into its modeling, EPA ensured that it was incorporating the best available information upon which to base its decisions.<sup>22,23</sup>

Additionally, commenter (2284-Kairos Aerospace) states Sherwin et al. (2023) is the most comprehensive summary to date of aerial remote sensing campaigns, based on a dataset of nearly one million site-level measurements. This dataset is over three orders of magnitude larger than the Zavala-Araiza et al. (2017) dataset (informed by several hundred ground-based, downwind measurements) which informed the leak generation rate of large emitters in EPA FEAST modeling.

Commenter (2284-Kairos Aerospace) states the current impact of EPA FEAST modeling underestimating the impact of large emitters is that alternative technologies with higher detection limits than the current BSER of OGI will have their real-world effectiveness underrepresented during modeling. This will unfairly favor routine OGI inspections during modeling and make it challenging for alternative technologies to achieve equivalency thresholds. By accurately

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<sup>20</sup> Id. at 74,752, 74,755.

<sup>21</sup> Cusworth et al., 2021, Chen et al., 2022

<sup>22</sup> Cusworth, D.H., Duren, R.M., Thorpe, A.K., Olson-Duvall, W., Heckler, J., Chapman, J.W., Eastwood, M.L., Helmlinger, M.C., Green, R.O., Asner, G.P., Dennison, P.E., Miller, C.E., 2021. Intermittency of Large Methane Emitters in the Permian Basin. Environ. Sci. Technol. Lett. <https://doi.org/10.1021/acs.estlett.1c00173>

<sup>23</sup> Chen et al. 2022

accounting for the presence of these large emitters, the benefits of an alternative screening method with the ability to screen many sites rapidly will be more accurately described. In addition, modeled mitigation results will likely more accurately reflect what is commonly accepted regarding methane emissions in that the large emissions make up a disproportionate number of total emissions in a given basin / asset base.

Commenter (2284-Kairos Aerospace) continues, producing high quality studies such as these often requires some form of partnership between an agent capable of collecting measurements at scale (e.g., a company or government entity), and academic researchers positioned to produce transparent data-driven analysis and conclusions unbiased by commercial motivations.<sup>24</sup> This process is further backed by peer-review and publication in reputable scientific journals. The commenter strongly encourages EPA to continue to consider similar quality evidence of emission distributions to ensure policies are based upon the best available data and independently derived science. Studies that lack independent authors without a commercial interest are a fraught starting point for high quality, science-backed policy.

Commenter (2284-Kairos Aerospace) adds FEAST modeling results showed that due to their rarity, a single generated large-emitter had a marked impact on simulation results if it were to be generated. Introducing a higher probability of generating large emitters in FEAST modeling may alleviate some of the requirements for a high number of simulation rounds carried out by the EPA FEAST modeling.

Commenter (2284-Kairos Aerospace) also notes EPA modeling captures the full distribution of emissions by constructing model plant representations from three separate distributions (fugitive emissions components, tanks, and large emitters). Of particular interest is the emissions distribution for the large emitters, which was generated by augmenting the Cusworth et al. (2021) dataset with a lognormal distribution between 10 kg/hr and 70 kg/hr to account for deterioration of detection capabilities below 70 kg/hr.

Commenter (2284-Kairos Aerospace) continues, new evidence from Sherwin et al. suggests that 1.7%, 3.4% and 4.3% of site-level emissions are above 10 kg/hr, for the Appalachia, Denver-Julesburg and Permian basins respectively. With the probability of generating a large emitter in the FEAST modeling carried out by the EPA at 2% maximum, this suggests that the EPA FEAST modeling underestimates emissions from large emitters, especially in basins prone to larger emissions such as the Permian Basin.

Response II-14-24: EPA acknowledges the commenters' input.

Comment: Commenter (2284-Kairos Aerospace) states this supposition is driven by the possible intermittency of super emitters. Cusworth et al. (2022) find short-lived, large sources to contribute a significant amount (~40-50%) of basin-scale methane. Less frequent surveys (even ones using advanced screening technologies) could completely miss these short-duration

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<sup>24</sup> e.g., Tyner & Johnson, 2021; Cusworth et al., 2021; Chen et al., 2022

emissions if they start and end between surveys. The probability of this happening grows as the survey frequency decreases, which in turn leads to an underestimate of total emissions.

Commenter (2284-Kairos Aerospace) adds less frequent surveys will still find large emissions, but they will also be less constrained in quantifying its duration (and thus the summed volume of methane emitted). At monthly frequency, there is a tighter window within which it is possible for a detected emission to be leaking. With decreasing survey frequency, the impact of the detected emission will not be as well understood. It could be emitting for a shorter or longer period than assumed, and thus be over OR underrepresented. In the words of the study authors themselves, “A revisit strategy with long revisit intervals (e.g., months) would not be able to easily distinguish between these timescale categories and could potentially miss a sizable contribution from short-lasting emission sources.” This points to an additional benefit from the high frequency survey programs (even when using fewer sensitive instruments) that are potentially underrepresented in EPA’s FEAST modeling.

Response II-14-25: EPA acknowledges the commenters’ feedback and agrees that more monitoring would increase the identification of these large emission events.

Comment: Commenter (2433-EDF et al.) states new studies published in the year since EPA issued its initial proposal have only further solidified the problem posed by super emitters, documenting the widespread existence of sources emitting at or well-above EPA’s proposed super emitter threshold of 100 kg/hr. A study by Chen et al. released in March 2022 found that just 118 out of 958 sources surveyed in the Permian Basin using an aerial monitoring program were responsible for 50% of total emissions from the region.<sup>25</sup> Another study released in July 2022 found that super-emitting sources were responsible for nearly 40% of total methane emissions between 2019 and 2021 across five major oil and gas basins: the San Joaquin Valley in California, the Uinta Basin in Utah, Denver-Julesburg Basin in Colorado, the Permian Basin in Texas and New Mexico, and the Marcellus Shale Basin in Pennsylvania.<sup>26</sup> The study included super-emitting sources from oil and gas production, wet manure from animal feedlots, large landfills, and coal mine venting, but found that oil and gas production sources made up the majority of super emitters in almost every basin except the Marcellus Shale, which was more heavily influenced by coal mine venting.<sup>27</sup>

Commenter (2433-EDF et al.) states recent measurement-based studies again confirm that total oil and gas emissions are much higher than official estimates.<sup>28</sup> This discrepancy is attributed to

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<sup>25</sup> Chen et al., Quantifying Methane Emissions in New Mexico Permian Basin, *supra* note 196.

<sup>26</sup> Daniel H. Cusworth et al., Strong Methane Point Sources Contribute a Disproportionate Fraction of Total Emissions Across Multiple Basins in the United States, 119 *Proceedings of the Nat’l Acad. of Scis.* 1, 1–4, 6 (2022), <https://www.pnas.org/doi/10.1073/pnas.2202338119> [hereinafter “Cusworth et al., Strong Methane Point Sources “].

<sup>27</sup> *Id.* at 3–4.

<sup>28</sup> Sherwin et al., *supra* note 166 (combining Carbon Mapper and Kairos surveys with an expanded version of the emissions simulation tool from Rutherford et al. 2021 to “infer emissions inventories for six regions in the United States comprising 52% of onshore oil and 29% of gas production over fifteen aerial campaigns. Total estimated



“low-probability but high-consequence sources [that] can contribute the majority of methane emissions from an oil and gas producing region” but that are not well characterized in official inventories.<sup>29</sup> These studies underscore that addressing super emitters is centrally important in efforts to drive down total emissions.

Commenter (2433-EDF et al.) notes studies have also identified and quantified ultra-emitters.<sup>30</sup> These sources are responsible for some of the largest methane plumes ever observed. An international study released in July 2022 used global satellite monitoring data to identify multiple ultra-emitters in the Permian Basin with emission rates ranging from 700 kg/hr up to a whopping 24,000 kg/hr.<sup>31</sup> NASA satellite monitoring data from the Earth Surface Mineral Dust Source Investigation mission has also identified at least one ultra-emitting facility in the Permian Basin with a recorded emissions rate of 18,300 kg/hr of methane released.<sup>32</sup>

Commenter (2433-EDF et al.) notes despite the significant contribution of these sources to overall methane pollution, these emission events can be difficult to capture through periodic monitoring programs because they tend to be intermittent and unpredictable.<sup>33</sup> Indeed, we explained in our comments on EPA’s initial proposal that regular LDAR can fail to capture super emitters, especially within the timeframe required for mitigation.<sup>34</sup> For instance, if a super emitter source at a well site starts leaking after an inspection, it could continue to leak 100 kg/hr

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emissions range from 9.63% of natural gas production, roughly nine times the US government estimate, to 0.75% in a high-productivity gas-rich region.”); William Kunkel et al., Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure By Aerial LiDAR, Earth ArXiv (2023) (preprint), <https://eartharxiv.org/repository/view/4895/> (Carbon Mapper and Bridger measurements in the Permian at 7,920 oil and gas production facilities increase the total emission rate for the survey region by a factor of 3.0 after controlling for scale factors such as survey area and number of scans per facility); Matthew Johnson et al., Creating Measurement-Based Oil and Gas Sector Methane Inventories Using Source-Resolved Aerial Surveys, Rsch. Square (2022) (preprint), <https://www.researchsquare.com/article/rs-2203868/v1>.

<sup>29</sup> Sherwin et al., *supra* note 166, at 4.

<sup>30</sup> See, e.g., Sudhanshu Pandley et al., Satellite Observations Reveal Extreme Methane Leakage from A Natural Gas Well Blowout, 116 Proc. Nat’l Acad. Sci. 2376, 26376–81 (2019), <https://www.pnas.org/doi/10.1073/pnas.1908712116> [hereinafter “Pandley et al., Satellite Observations of Well Blowout”].

<sup>31</sup> Daniel J. Jacob, et al., Quantifying Methane Emissions from the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane, 22 Atmos. Chem. Phys. 9617, 9617–46 (2022), <https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022.pdf>.

<sup>32</sup> Nat’l Aeronautics & Space Admin. Jet Propulsion Lab., Methane ‘Super emitters’ Mapped by NASA New Earth Space Mission (Oct. 25, 2022), <https://www.nasa.gov/feature/jpl/methane-super-emitters-mapped-by-nasa-s-new-earth-space-mission> [hereinafter “NASA Jet Propulsion Lab, Methane Mapped by Earth Space Mission”].

<sup>33</sup> 2022 Joint Environmental Comments, *supra* note 1, at 63. See also Cusworth et al., Strong Methane Point Sources, *supra* note 201, at 5; 87 Fed. Reg. at 74747.

<sup>34</sup> See, e.g., 2022 Joint Environmental Comments, *supra* note 1, at 68. See also Cusworth et al., Strong Methane Point Sources, *supra* note 201, at 6; 87 Fed. Reg. at 74747 (explaining that periodic LDAR can miss these emission events).

unabated for three months—the period of time between quarterly inspections. That would equate to over 17.5 million metric tons of CO<sub>2</sub>-e, or the annual emissions of 5,400 passenger cars.<sup>35</sup>

But, as noted above, many sources emit well above even EPA’s 100 kg/hr threshold. For example, a 2018 natural gas well blowout in Ohio was initially estimated to have a leak rate of 100 million cubic feet of natural gas per day—twice that of the Aliso Canyon leak. For the next twenty days, the well emitted an estimated 60,000 tons of methane.<sup>36</sup> From a climate standpoint, this amount is larger than some entire countries’ annual emissions and is equivalent to the emissions of one million passenger vehicles driven for a year.<sup>37</sup> Moreover, super emitters are widespread across the oil and gas sector, encompassing numerous sources scattered over broad geographic areas.<sup>38</sup> New studies from 2022 have identified large emission events at well sites, gas processing plants, compressor stations, storage tanks, and gathering pipelines.<sup>39</sup> As a result, there is a significant need for EPA’s standards to address super emitters.

Commenter (2433-EDF et al.) states there are a number of individuals and institutions that are already tracking super emitters, so it is efficient and practical for EPA to develop approaches that can leverage these independent data sources to quickly mitigate huge emission events. As discussed above, scientists have been studying super emitters for years and have gathered substantial amounts of data on the sources and locations of these emitters. Multiple organizations have also developed programs to identify super emitters, collecting information on the location, facility type, and emission rates of these sources across the oil and gas industry.<sup>40</sup> For instance both Carbon Mapper and EDF’s PermianMAP project provide interactive maps with the location and emission rate of methane emitting sources.<sup>41</sup> Satellites under development will also soon provide information on the location of super emitter events. Even other federal and international

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<sup>35</sup> 100 kilograms \* 24 hrs = 2,400 kilograms \* 90 days = 216,000 kilograms. Env’t Def. Fund, Understanding the Near- and Long-Term Impacts of Emissions, [https://www.edf.org/understanding-near-and-long-term-impacts-emissions?co2=11&ch4=60000&n2o=6&hfc\\_134a=0](https://www.edf.org/understanding-near-and-long-term-impacts-emissions?co2=11&ch4=60000&n2o=6&hfc_134a=0) (last visited Feb. 4, 2023) [hereinafter EDF Methane Calculator].

<sup>36</sup> Pandley et al., Satellite Observations of Well Blowout, *supra* note 205, at 26376, 26378–79.

<sup>37</sup> EDF Methane Calculator, *supra* note 210.

<sup>38</sup> 2022 Joint Environmental Comments, *supra* note 1, at 98, 126–27, 200.

<sup>39</sup> Chen et al., Quantifying Methane Emissions in New Mexico Permian Basin, *supra* note 196, at 4318, Figure 1(d); Jevan Yu et al., Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin, 9 *Env’t Sci. Tech. Lett.* 969, 969–74 (2022), <https://pubs.acs.org/doi/10.1021/acs.estlett.2c00380>; see also Carbon Mapper, Carbon Mapper Data Portal, [https://data.carbonmapper.org/map#b=Mapbox\\_Satellite\\_Retina&l=AVIRIS\\_SOURCES\\_CLUSTER\\_MAP\(1\),AVIRIS\(1\),MITIGATION\\_EXAMPLES\(1\),AVIRIS\\_SOURCES\\_CLUSTER\(1\)&vm=2D&ve=-123.941240,31.444673,-91.641435,45.657885&pl=false&pb=false&tr=true&d=2023-02-01&tlr=days](https://data.carbonmapper.org/map#b=Mapbox_Satellite_Retina&l=AVIRIS_SOURCES_CLUSTER_MAP(1),AVIRIS(1),MITIGATION_EXAMPLES(1),AVIRIS_SOURCES_CLUSTER(1)&vm=2D&ve=-123.941240,31.444673,-91.641435,45.657885&pl=false&pb=false&tr=true&d=2023-02-01&tlr=days), (last visited Feb. 4, 2023) [hereinafter “Carbon Mapper, Data Portal”]; Env’t Def. Fund, Permian Methane Analysis Project (MAP): Equipment Emissions, <https://data.permianmap.org/pages/operators> (last visited Feb. 4, 2023) (identifying major emission events at flares) [hereinafter EDF, Permian (MAP)"]; 87 Fed. Reg. at 74748 (stating that the most widely known sources of super emitter events are controlled tank batteries, flares, natural-gas driven pneumatic controllers, and fugitive emission components).

<sup>40</sup> See, e.g., Benjamin Hmiel et al., Empirical Quantification of Methane Emission Intensity from Oil and Gas Producers in the Permian Basin, 18 *Env’t Rsch. Letters* 024, 029 (2023), <https://iopscience.iop.org/article/10.1088/1748-9326/acb27e> [hereinafter “Hmiel et al., Empirical Quantification of Producers in the Permian Basin”].

<sup>41</sup> Carbon Mapper, Data Portal, *supra* note 214; EDF, Permian (MAP), *supra* note 214.

agencies have been collecting data on super emitters, including NASA’s Jet Propulsion Lab and the United Nations Environment Programme’s Methane Alert and Response (MARS) program.<sup>42</sup> States are also beginning to conduct monitoring for super emitters. California plans to deploy satellites, starting with two launches this year, to monitor for plumes of carbon dioxide and methane across the state.<sup>43</sup>

Commenter (2433-EDF et al.) states utilizing this kind of independent monitoring information to identify major emission events and help to ensure action to eliminate them also makes sense from a practical standpoint. As the industry faces increasing scrutiny for its emissions, owners and operators will have bigger incentives to avoid detecting and disclosing large emissions.<sup>44</sup> Independent, third-party monitoring data can help to build confidence that efforts to reduce emissions are working. These data can be an important addition to the current industry self-reporting systems, under which numerous studies show that actual emissions are far higher than official estimates and do not align with operators’ stated actions and goals.<sup>45</sup>

Commenter (2433-EDF et al.) states these types of independent checks and mandatory reporting and corrective action programs like SERP are well established and consistent with past EPA practice. For example, EPA, along with the U.S. Coast Guard, administers the National Response Center program, which houses a reporting hotline that allows members of the public to report spills and discharges of oil and other dangerous and hazardous material.<sup>46</sup> Reports to the hotline can trigger obligations on the part of EPA, the Coast Guard, and other federal agencies, as well as responsible facilities, to investigate and, where necessary or appropriate, take action to clean-up and mitigate the spill or discharge in accordance with the National Contingency Plan.<sup>47</sup> EPA also issued fenceline monitoring standards for petroleum refineries in 2015 that require refineries to set up systems around refinery fencelines to monitor for benzene as an indicator pollutant for other hazardous pollutants.<sup>48</sup> If monitoring shows that benzene levels exceed a certain threshold,

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<sup>42</sup> See, e.g., NASA Jet Propulsion Lab, Methane Mapped by Earth Space Mission, *supra* note 207; United Nations Env’t Programme, Methane Alert and Response System (MARS), <https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo-action/methane-alert-and-response-system-mars> (last visited Feb. 4, 2023). See also Carbon Mapper, Resources, <https://carbonmapper.org/resources/>, (last visited Feb. 4, 2023) (listing related methane monitoring programs).

<sup>43</sup> Cal. Air Res. Bd., California Satellite Partnership, <https://ww2.arb.ca.gov/our-work/programs/california-satellite-partnership> (last visited Feb. 6, 2023).

<sup>44</sup> Cynthia Giles, Part 4: Preventing Widespread Violations that Threaten Climate Goals at 47, in *Next Generation Compliance: Environmental Regulation for the Modern Era* (2021).

<sup>45</sup> See, e.g., Env’t Def. Fund, PermianMAP Final Report: A Look Back at Key Findings and Takeaways from the Permian Methane Analysis Project (2021). <https://blogs.edf.org/energyexchange/files/2022/11/PermianMAPFinalReport.pdf> (finding that numerous operators had methane intensities that far exceeded their stated targets). See also Hmiel et al., *Empirical Quantification of Producers in the Permian Basin*, *supra* note 215 (using data gathered during aerial observations to calculate individual operator methane intensities).

<sup>46</sup> U.S. Env’t Prot. Agency, National Oil and Hazardous Substances Pollution Contingency Plan (NCP) Overview (last updated Mar. 25, 2022), <https://www.epa.gov/emergency-response/national-oil-and-hazardous-substances-pollution-contingency-plan-ncp-overview> [hereinafter “EPA NCP Overview”]. See also 87 Fed. Reg. at 74749.

<sup>47</sup> *Id.*; See also 40 CFR, pt. 300, subparts D & E; *id.* § 300.185 (providing for non-governmental participation in response efforts).

<sup>48</sup> 40 CFR § 63.658; 87 Fed. Reg. at 74748 (citing 79 Fed. Reg. 36880, 36920 (Jun. 30, 2014)).

the refineries are then required to conduct a root cause analysis and take corrective action.<sup>49</sup> Refineries also must report their fenceline monitoring data to EPA, which makes the data publicly available on its Enforcement and Compliance History Online (ECHO) site.<sup>50</sup> Other federal agencies have also developed similar third-party programs to assess compliance with a wide variety of regulations, from food safety and labeling to energy and water efficiency standards.<sup>51</sup>

Commenter (2433-EDF et al.) states SERP, as well as the EPA programs noted above, all build on the longstanding and well-established role that independent parties have played in reporting potential violations of CAA standards to EPA. “Reports from the public have led to state and federal enforcement cases and ultimately served environmental protection well.”<sup>52</sup> To that end, EPA has long “invite[d]” independent third parties to assist the agency in carrying out its environmental protection duties under the CAA “by identifying and reporting environmental violations” via its online Report an Environmental Violation webpage or by contacting relevant regional staff.<sup>53</sup> EPA’s online reporting tool is housed in the agency’s ECHO database, which includes EPA, state, local, and tribal compliance and enforcement records that are reported to EPA national databases.<sup>54</sup>

Response II-14-26: EPA acknowledges the commenters’ input and support for the Super Emitter Program.

### ***14.3.2 Existing State Plans***

Comment: Commenter (2220-Wyoming Department of Environmental Quality (WDEQ)) questions the fundamental basis for the proposed SERP. In accordance with Wyoming’s Environmental Quality Act (W.S. §§ 35-11-101 et seq.), the commenter has a well-established, well-functioning complaint process through which third parties and members of the general

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<sup>49</sup> 40 CFR § 63.658.

<sup>50</sup> U.S. Env’t Prot. Agency, EPA Launches New Online Tools to Provide Communities With Information on Environmental Enforcement and Compliance (Oct. 2, 2022), <https://www.epa.gov/newsreleases/epa-launches-new-online-tools-provide-communities-information-environmental>; see also 2022 Joint Environmental Comments, *supra* note 1, at 136–37 (noting that EPA issued Compliance Assurance Monitoring and Credible Evidence Revisions rulemakings which allow EPA and the public to use non-reference test data for compliance monitoring and enforcement rules and require compliance assurance monitoring at major sources and corrective action when an exceedance is detected to return the facility to normal operations).

<sup>51</sup> Administrative Conference of the United States: Adoption of Recommendations, 78 Fed. Reg. 2939, 2941 (Jan. 15, 2013) (setting forth recommendations for agencies to consider when developing third-party compliance assessment programs); Lesley K. McAllister, University of San Diego School of Law, Third-Party Programs to Assess Regulatory Compliance, at 9, Table 1 (2012), [https://www.acus.gov/sites/default/files/documents/Third-Party-Programs-Report\\_Final.pdf](https://www.acus.gov/sites/default/files/documents/Third-Party-Programs-Report_Final.pdf) (summarizing information about eight different third-party compliance assessment programs across a number of federal agencies).

<sup>52</sup> U.S. Env’t Prot. Agency, Report an Environmental Violation, General Information (last updated July 5, 2022), <https://www.epa.gov/enforcement/report-environmental-violation-general-information>.

<sup>53</sup> *Id.*; U.S. Env’t Prot. Agency, ECHO: Report Environmental Violations (last updated Sept. 21, 2022), <https://echo.epa.gov/report-environmental-violations>.

<sup>54</sup> U.S. Env’t Prot. Agency, Enforcement and Compliance History Online: About the Data (last updated Dec. 14, 2022), <https://echo.epa.gov/resources/echo-data/about-the-data>.

public can report any pollutant emission event of concern, regardless of whether it is a large-scale or small-scale event. The agency's compliance program promptly handles inspections and investigations, addressing any identified issues. Requiring that an EPA-approved third-party entity notifies operators of a potential super-emitting event convolutes the compliance process and diverts both WDEQ and operator resources from providing a more-immediate follow-up to correct the issue and also redirects resources away from other critical work.

Response II-14-27: EPA recognizes the commenter's concern and in the final rule, a third party must now submit notifications to the EPA, which has the obligation to review the data prior to submitting information to the owner or operator. The obligation to conduct investigation is on the owner or operator of an oil and gas natural facility and there isn't an expectation on a state, local, or tribal agency to investigate.

Comment: Commenters (2240-Rose Rock Environmental Services, LLC, 2292-West Virginia Attorney General et al.) note EPA proposes cutting States out of the process for dealing with super emitter events altogether.<sup>55</sup> Right now, when a large-emission event is detected, States are notified. States then review and respond to the event accordingly. But under EPA's Supplemental Proposal, third parties who identify large methane leaks would notify owners and operators directly. That notice then obligates the plant's operators to conduct a root-cause analysis and take corrective action. (Id) The States are effectively cut out of the process. Perhaps States may play some tag-along role in following up with the companies after they respond to a compulsory super emitter notice. But other than that minimal bit, States are effectively sidelined. Commenters (2292-West Virginia Attorney General et al.) further believes that EPA does not have authority to implement a SERP of this kind at all. But that fundamental problem aside, the agency's failure to consider the present role of States in performing these functions is emblematic of the Supplemental Proposal's lack of concern for the federalism principles built into the CAA.

Response II-14-28: In the December 2022 supplemental proposal, there was not an intent to "cut" the states out of the process and the program was designed to provide actionable data (*i.e.*, EPA verified super-emitter event data) to an owner or operator without delay. EPA has received many comments explaining how this approach is problematic, is finalizing the rule with EPA is a centralized position to take in notifications from third parties through a public facing Super Emitter Portal, built with transparency in mind. The goal of this program in the final rule is to inform owner or operators when these large emission events happen in a short time frame, and the Super Emitter Portal is the mechanism for informing them as well as the local authority and public at large.

Commenter (2240-Rose Rock Environmental Services, LLC) states there are no guidelines in the proposed rules for how third-party monitoring should be conducted and no process to verify findings before making them publicly available. States typically have programs in place for citizens to file complaints regarding emissions from a regulated facility. The States are in the best position to address such issues under their current rules and regulations. Commenter (2240-

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<sup>55</sup> 87 Fed. Reg. at 74,747.

Rose Rock Environmental Services, LLC) argues states typically have programs in place for citizens to file complaints regarding emissions from a regulated facility. The States are in the best position to address such issues under their current rules and regulations. The SERP should be removed from the proposed rule.

Response II-14-29: EPA acknowledges the commenter's views, and in the final rule EPA has developed a mechanism to verify data submitted to the EPA through the Super Emitter Program. For awareness, this program is not designed for citizens to file "complaints". EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.. Also, the Super Emitter Program is not intended to replace any state, local, or tribal authority address complaints received by the general public.

Comment: Commenter (2296-NMED) states New Mexico's Part 50 rules allows for agency-approved alternative monitoring plans to address equipment leak requirements through equally effective methods, incenting industry, spurring technology development, and reducing waste. The rules allow the commenter to terminate such a plan if it finds the owner or operator failed to comply with any of the plan's provisions and did not promptly notify NMED. Similarly, EPA should follow the commenter's rules embrace of fuel cells as an air pollution control device, a climate and air quality solution which also reduces waste. Like NMED's Part 50 rules, EPA should establish that violations of the proposal are prohibited activities and provide that credible evidence obtained by the agency or provided by a third-party may be used as a basis for establishing whether a violation occurred.

Response II-14-30: EPA recognizes the commenters take, however EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. Receiving a Super Emitter Program notification from the EPA triggers a responsibility of the owner or operator to investigate the cause of the emission event, if the investigation identifies a deviation of a regulation, then they would be required to repair and report as required by the applicable federal regulation.

### ***14.3.3 Super Emitter Events are Predominantly Infrequent and Short-Duration***

Comment: Commenter (2315-New York State Department of Environmental Conservation (DEC)) does not believe that EPA has adequately addressed super emitters in this proposal. A range of studies published between 2013 and 2015 characterize super emitters as a small portion of sources emitting a larger portion of emissions.<sup>56</sup> This does not necessarily mean each of these sources emit at the level EPA has determined as the super emitter threshold. While the proposal

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<sup>56</sup> Brandt, A.R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343; Miller, S.M., et al. 2013. Anthropogenic Emissions of Methane in the United States. Proceedings of the National Academy of Sciences. December 10, 2013.

may identify large emission sources in areas where third-party entities may want to monitor, it does not account for the various smaller sources that may be hard to reach nor accessible by the public.

Response II-14-31: EPA acknowledges the commenters' input. EPA has developed this program in response recent studies, which indicate a small portion of sources contribute ~50 percent of the methane emission in the oil and gas sector, and on a global scale, the largest of these emissions sources globally, may represent as much as 12% of global methane emissions from oil and gas production and transmission. The goal of this program is to identify when these large emission events as they, so they can be identified and mitigated, if necessary.

Comment: Commenter (2258-MSD) states a sound program addressing the largest sources of methane emissions can have significant environmental benefits. However, as recent experience with flyovers in Pennsylvania has demonstrated, most of the large emission sources are not from oil and gas operations. If U.S. EPA believes that a SERP is warranted, it should be a stand-alone program addressing all such sources and should not be limited to the oil and gas sector.

Response II-14-32: EPA recognizes the commenters' thoughts, this rule is limited to the oil and gas sector, however EPA may choose to evaluate similar programs for other sectors later and through notice-and-comment rulemaking.

Comment: Commenter (2353-CrownQuest Operating, LLC.) argue the following studies lean on the tail-heavy site emission distribution to suggest that only a small number of "super emitter" sites are responsible for most of the oil and gas industry's emissions.

- Super emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions
- Assessment of Methane Emissions from the US Oil and Gas Supply Chain
- Intermittency of Large Methane Emitters in the Permian Basin
- Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories
- Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey

Commenter (2353-CrownQuest Operating, LLC) states however, the EPA assumes that the requirements in the OOOOb/c rule would reduce the number of super emitter events when none of the referenced studies show any research to indicate such a conclusion. The referenced studies gathered data on emissions but not on inspections. Essentially, the EPA hopes to avoid super emitter events by increasing inspection frequency. However, they present no research that would suggest such a correlation.

Commenter (2353-CrownQuest Operating, LLC.) notes in the rule's preamble, the EPA admits that "a cost-effective inspection program can therefore miss some of these super emitter events, even if implemented in accordance with the proposed standards."<sup>57</sup> The EPA's analysis of the proposed rules would not eliminate most super emitter events. Furthermore, the EPA states in the

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<sup>57</sup> Preamble pg. 152.

preamble that many high-rate events are due to human error, such as the pumper accidentally leaving a valve or hatch open after maintenance. Most of the time, these events are unpredictable but quickly resolved when discovered shortly after by existing operating practices.

Commenter (2353-CrownQuest Operating, LLC.) states the oil and gas industry already has a financial incentive to prevent such accidental losses and voluntary industry initiatives to reduce the frequency of such events. Additionally, there is little evidence to show that more frequent inspection decreases the frequency of these events or increases discovery. As previously proposed, most events are due to human error and are discovered soon after the error happens by the person that caused it. To say that quarterly inspections at a well site would decrease the chances of a super emitter is not backed by research.

Response II-14-33: EPA acknowledges the commenters' input and EPA disagrees with the assumption that additional monitoring would not lead to more large emission events being identified. The goal of this program is to provide owners or operators with actionable information that a large emission event has been detected, so that an owner or operator can investigate the cause and if necessary, eliminate the emission.

Comment: Commenter (2336-Kuva Systems) is not aware of any study suggesting that all super emitters are persistent as currently modeled. Instead, plane-based studies have for several years concluded that super emitters are predominantly intermittent. A major shortcoming of these plane-based studies is that the duration of super emitters is poorly characterized as measurements are taken very infrequently, often several days apart. Moreover, it is not clear if emissions that are characterized as persistent by plane detections are really persistent or if they are intermittent and just happen to emit on a second overflight. More recently, continuous monitoring has been used to investigate the intermittency of super emitters more closely. Of particular interest is the study from Wang et al.<sup>58</sup> that published a table showing the duration of super emitters based on studies in two production basins, reproduced below:

[Figure 1]: Reproduction of Figure 5 of Wang et al. showing leak durations and wait times as observed by continuous monitoring devices in 2 N. American basins

Commenter (2336-Kuva Systems) states a shortcoming of this study was that the emissions were not attributed to equipment groups and that the study was limited to two production basins. In order to address these gaps Kuva Systems employees conducted an analysis of the intermittency of super emitters for Kuva cameras that are installed at Kuva customers in the USA oil and gas industry.

Commenter (2336-Kuva Systems) notes the evaluation included 25 Kuva cameras located at sites in five different oil and gas production basins in the United States (Permian Basin, Eagleford, East Texas, North Dakota, and Oklahoma). The sites were all complex upstream production sites, except for one gas processing facility and one compressor station. Each site had one or

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<sup>58</sup> Wang et. al. "Multiscale Methane Measurements at Oil and Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting", <https://pubs.acs.org/doi/full/10.1021/acs.est.2c06211> (Oct. 6, 2022).



more Kuva cameras installed for a period of 2 to 18 months. The camera took images of each field-of-view every 30 seconds to 3 minutes as long as environmental conditions were within the operating envelope. The objective of the study was to analyze the duration and frequency of sites that exhibit super emitters. The goal was not to analyze the frequency of occurrence of super emitters. Therefore, the selection criteria for cameras to be included in this study was that they had at least one super emitter event occur since their installation. A super emitter event was defined as an emission of approximately 10 kg/h or larger. The study was performed at the beginning of February 2023.<sup>59</sup> All super emitters from these sites were attributed by visual review of the images to the following four equipment types: compressors, controlled tanks, separators, and flares.

Commenter (2336-Kuva Systems) states Figure 2 below shows independent time series of representative monitoring cameras from their date of installation, showing emission signatures for flares, tanks, and one separator. The figure shows the irregular short- and long-term behavior of super emitters for all three equipment types.

Commenter (2336-Kuva Systems) states Figure 3 shows the temporal distribution of the super emitter events detected by Kuva cameras. Over 1,000 events were detected by the subset of 25 installed cameras. We find a mean super emitter duration of 21 minutes for all equipment types, and a standard deviation of 43 minutes. These values confirm the general distribution of super emitters as shown by Wang et.al. and they demonstrate that this distribution holds true for tanks, flares and separators and for five production basins.

Substantially all super emitters had a duration of less than one day. We therefore recommend for EPA to use a “duration” factor of one day as part of EPA’s FEAST simulations.

[Figure 2: Example timelines of emission events for a representative set of installed cameras, from date of installation (Day 0) through 3-4 months of continuous monitoring operations. Cumulative daily operations are shown as individual columns, with each event category shown as a different color, with a length equal to the percentage of a 24-hour for each category. Super emitter events are in almost all observed cases less than a day long and generally constitute 1%-10% of a day in cumulative duration (15 minutes to ~ 2 hours).]

[Figure 3: Histogram of super emitter event durations by equipment type. The distribution contains over 1,000 self-defined “super emitter” events from 25 individual cameras installed at a variety of upstream production facilities. The emitter distribution has a mean duration ( $\mu$ ) of 21 minutes and a standard deviation ( $\sigma$ ) of 43 minutes.]

Response II-14-34: EPA acknowledges the commenters’ input for the Super Emitter Program. EPA recognizes the intermittency of these events and increase monitoring through the program

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<sup>59</sup> Commenter (2336-Kuva Systems) also compiled and anonymized multi-month time-series datasets for each camera and provided them for a statistical analysis conducted by Daniel Zimmerle and colleagues of Colorado State University (see separate comment by Daniel Zimmerle and Colorado State University for Docket No. EPA-HQ-OAR-2021-0317).

increases the probability of catching consecutive events and increases the likelihood of identifying the underlying cause(s).

Comment: Commenter (2399-GPA Midstream Association) argues the Proposed Rule introduces “super emitter” events as very rare and “typically caused by abnormal operating conditions or malfunctions.”<sup>60</sup> EPA then states that “the November 2021 Proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent ... or detect and mitigate ... most of these large emissions events.”<sup>61</sup> Thus, EPA anticipates that implementing these new regulations would make “super emitter” events extremely rare.<sup>62</sup> That itself demonstrates that adopting this additional and extraordinary program is not justified by actual record-based evidence.

Commenter (2399-GPA Midstream Association) continues, regardless of how many larger emission events would remain, if any, a new quasi-enforcement program is not required to address them. EPA’s proposal is not intended to address intentional venting as part of normal operations or maintenance. *Id.* at 74,747, n. 101. Thus, a “super emitter” event would present an enforcement issue, not a new regulatory issue, as these events would only arise through violations of the regulations. *See id.* at 74,753 (“Where one of these facilities is determined to be the cause of a super emitter emissions event; it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement”); *id.* (Where flares cause a super emitter event they are not in compliance with existing regulations).

Commenter (2399-GPA Midstream Association) recognizes that EPA claims this extraordinary program is necessary as “a backstop to address the large contribution of super emitters to the pollution from this sector.” *Id.* at 74,747. However, EPA offers no supporting data and provides no reason why traditional federal, state, and citizen suit enforcement mechanisms would be unable to fully address these events, if any occur under a new set regulation once finalized. EPA found additional monitoring would not be cost-effective, and thus, EPA’s proposed program would not increase the availability of monitoring capabilities or the likelihood that sources will be monitored. Instead, the SERP would only change how monitoring information may be handled if an alleged “super emitter” is discovered.

Commenter (2399-GPA Midstream Association) states the Supplemental Proposed Rule provides no actual data or any other credible explanation of why monitoring information cannot be used for traditional regulator responses, as may be appropriate under the CAA. The Supplemental Proposed Rule also infers that these events are somehow different than other

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<sup>60</sup> 87 Fed. Reg. at 74,746-47; *see also id.* at 74,748 (the percentage of super-emitting sources is so small that “it is not cost-effective to impose additional inspection costs on every source”), *id.* at 74,749 (where a source is compliant with regulations “the EPA does not expect unintentional releases at these very high levels to occur in normal operations”).

<sup>61</sup> *Id.* at 74747.

<sup>62</sup> This is the best description in the record available to the public, given that EPA has not identified how many alleged “super emitters” there are under current conditions or estimated a reduction in “super emitters” if measures like the proposed rules were promulgated and implemented.

potential regulatory violations because they are intermittent. See, e.g., 87 Fed. Reg. at 74,747 (stating that “many such large emissions events are intermittent and can occur at different sites over time”). To the extent that EPA is claiming that the intermittent nature of these alleged events presents an unusual problem for traditional state, federal, or citizen enforcement, it provides no data or evidence to support such a claim. In fact, many types of alleged environmental violations occur on an intermittent basis, yet they have been addressed with existing enforcement tools – and without deputizing private parties well beyond the authority provided by the CAA. To the extent that a facility is out of compliance and truly causing significant methane emissions, traditional enforcement mechanisms are available.

Response II-14-35: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. If an owner or operator identifies any deviations to the applicable regulations identified as part of that investigations, it would be addressed through reporting provisions incorporated in the final rule.

## **14.4 Program Design**

### ***14.4.1 Reporting Requirements***

Comment: Commenters (2177-Ute Indian Tribe, 2222-Wisconsin Department of Natural Resources, 2227-Western Energy Alliance, 2410-California Office of the Attorney General et al.) request that reports for designated facilities covered by a state, tribal or local agency be sent to the responsible entity.

Commenter (2177-Ute Indian Tribe) responds to EPA’s solicitation of comment on requiring the submission of a written report within 15 days of completing the root cause and corrective action to the Agency and delegated state authority. Commenter believes if a designated facility is covered by a state or tribal plan, all notifications should be submitted to the state or tribe in question. An annual report to EPA would be sufficient.

Commenter (2227-Western Energy Alliance) states written reports required to be submitted to EPA within 15 days of conducting a root-cause analysis should also be sent to the state or local agency.

Commenter (2177-Ute Indian Tribe) states notifications should include a copy of the super emitter event notification received, and information regarding basic corrective actions taken. Detailed information should be submitted along with annual compliance reports. If an annual compliance report is not required for the facility, a single annual report for any super emitter actions should be submitted.

Commenters (2222-Wisconsin Department of Natural Resources, 2410-California Office of the Attorney General et al.) agrees with EPA that when a third-party notifier submits a notification to an owner or operator, the party should provide a complete copy to EPA and the appropriate state

authority. The commenter believes that all subsequent reports and submittals should also be copied to the state. This will allow states to monitor compliance efforts under the SERP and will provide valuable information that states can use in their own compliance and enforcement efforts. The commenter also suggests that EPA clarify that EPA will enforce the requirements of the super emitter program. While reports submitted pursuant to the program can assist state agencies in enforcement of state regulations, enforcement of the requirements of the SERP itself should be centralized with EPA.

Response II-14-36: EPA acknowledges the commenters' input regarding how best to structure the reporting requirements in the Super Emitter Program. Any notifications and reports for this program will come through the super-emitter program and available to state, local, and tribal authorities as well as the general public.

Comment: Commenter (2247-Ohio Environmental Protection Agency) asks should either the approved notifier or the owner/operator of the super-emitting facility be required to report the event to appropriate emergency response organizations?

Response II-14-37: EPA thanks the commenters for their comment and this program does not require super-emitter data to be reported to emergency response organizations.

Comment: Commenter (2248-North Dakota Petroleum Council (NDPC)) states the specific information that would be required to document a source of emissions may not be detailed enough for an operator to evaluate what the third-party monitoring entity is seeing. For example, four decimal points are not accurate enough when there are nearby potential sources outside the control of the operation that is notified. Aerial imagery, or ground-based photographs, must be taken on the exact day and time of the alleged emissions with enough resolution to determine what might be going on at that time on the ground (truck traffic, maintenance equipment, workover rig, etc.).

Response II-14-38: EPA acknowledges the commenters' input and has revised the final rule to account for some uncertainty in the identification of the location of these super-emitter events. We disagree that reporting the latitude and longitude to 4 decimals (11 m<sup>2</sup>) is not accurate enough, in fact due to the size of these emissions it may be difficult to identify the exact source, to account for this we are requiring an owner or operator to identify any regulated equipment within 50 m<sup>2</sup> for inspection in the final rule. We agree that imagery from the time of the monitoring is helpful to determine if any maintenance was conducted during the super-emitter event, but we don't consider it to be mandatory as the investigation into a super-emitter event is required to evaluate any maintenance records that occurred during the identified super-emitter event.

Comment: Commenter (2626-Kayros) states the six elements required in each super emitter notification (location, technology description, documentation, flow rate, timestamp and signed certification) are consistent with the services provided by commercial providers of remote sensing data and provide sufficient information for the relevant operator to act. For the avoidance

of doubt, the EPA should clearly state that notifications should always include the associated imagery (from satellite, aerial or mobile sensor).

Response II-14-39: EPA acknowledges the commenters' suggestion and in the final rule we have clearly defined that third-party notifications must include appropriate imagery of the super-emitter event or equivalent proof of the event.

Comment: Commenter (2345-GHGSat Inc.) agrees with EPA's proposed elements of specific information for a notification to operators. The commenter is providing commentary on each of the six elements of information required:

- 1) The location of emissions in latitude and longitude coordinates. Commenter believes that this information is of the utmost importance. It is also relevant to recognize that remote sensing technologies need to apply inverse reconstruction techniques to identify the source of the emission. In areas where the installation footprint is relatively large or is isolated from neighboring infrastructure, then source allocating an emission does not pose a major challenge. The challenge arises when the emission originated in an area where infrastructure is dense. In this scenario, remote sensing technologies with high spatial resolution (like the commenter's satellite and aircraft) offer an advantage to minimize the error in the source allocation reconstruction process.

In the case of the commenter every satellite and aircraft detection come with a geolocation of the emissions source.

- 2) Description of the detection technology and sampling protocols used to identify the emissions. Commenter believes that this element can be fully documented at the registration period and then referenced on each of the detections.
- 3) Documentation depicting the emission and the site (e.g., aerial imaging with emission plume depicted). Commenter believes that this element is relevant. The colorless nature of methane prompts the need for spectroscopy techniques to identify and characterize the plume. This imagery must be part of the delivery. It will permit the characterization of the plume behavior at the time of detection, identifying the effect of wind and emission rate on the direction and dispersion of the plume. In the case of the commenter, every satellite detection provides imagery of the plume overlaid over the most recent commercial visible imagery map. Every aircraft detection provides imagery of the plume utilizing its own visible imagery taken at the time of the detection.
- 4) Quantified emissions rate. Commenter believes that this information is relevant. Based on the proposed definition of super emitter event, if an emission is detected by employing satellites, it is already understood that in fact is a super emitter event. In addition to the quantified emission rate, it is important to report the uncertainty associated with the emission rate calculation. This one could be express as percentage or a numerical deviation from the calculated rate.

In the commenter's case, every satellite and aircraft detection provide the calculated emission rate in kilograms per hour (kg/hr) and the associated uncertainty in that calculation express as plus or minus the deviation rate in kg/hr.

- 5) Date(s) and time(s) of detection and confirmation after data analysis that a super emitter emission event was present. Commenter believes this is another important parameter to be included in the report. Date and time of each detection should be reported in Universal Time Coordinated (UTC). This parameter can help in creating the baseline for such detection, and if recurrent, it can help in the determination of persistent or transient behavior of a leak. One aspect to note is that with every remote sensing technology, there is always a time between the detection of the plume and the actual processing of the data. Hence, the EPA should consider starting any action or regulatory timeline at the time of notification to the operator and not at the time of the detection. In the case of the commenter, every satellite and aircraft detection provide the associated date and time in UTC when the emission was detected.
- 6) A signed certification that the notifier is an EPA-approved entity for providing the notification, and the information was collected and interpreted as described in the notification. Commenter agrees that this signed certification provides fidelity to the receiving end that the information is coming from a vetted source. Commenter believes that this can be in the form of a weblink that traces back to the EPA's website hosting the list of third-party notifiers.

In addition to these six steps, commenter (2345-GHGSat Inc.) recommends including a description of the wind speed and direction that was considered at the time of the detection and that consequently used to characterize the leak.

Response II-14-40: EPA acknowledges the commenters' suggestion and the requirement in the final rule are reflective of these suggestions.

Comment: Commenter (2409-BP America Inc.) suggests that, in lieu of the third-party reports called for by EPA's proposal, EPA consider preparing an annual report (potentially in coordination with an academic institution), that includes an aggregated overview of total, validated emissions events sent to EPA by third parties, consolidated at a localized level but not at the site level. We believe a consolidated, comprehensive annual report validated and published by EPA would better achieve EPA's goal of enhanced transparency by allowing operators, regulators, and community members to see – in the aggregate – how implementation of EPA's methane regulations and the SERP program have reduced the frequency of super emitter emissions events.

Commenter (2409-BP America Inc.) believes an annual report will allow time for data review/verification and quality assurance, consistent with other EPA annual reports whose purpose is to increase transparency and community access to environmental data. Furthermore, an annual report could also allow industry, communities, and other stakeholders to see regionalized trends over time. By contrast, publishing individualized, privately sourced reports about operators could have the opposite effect and be misleading to the public. This approach

could shift attention to particular operators (many of whom may have taken prompt action or determined that no action was needed under SERP) merely because they were the focus of, or targeted by, third parties whose decisions may reflect a variety of priorities not necessarily in line with the priorities of EPA or the statute.

Response II-14-41: EPA acknowledges the commenters' input. However, an annual report that is only regional in specificity holds does not meet the transparency goals of this program to provide timely super-emitter to the public.

Comment: Commenter (2394-Earthworks) urges the EPA to create a streamlined process for determining and notifying responsible operators so that emissions are quickly addressed. The EPA should not require multiple detections before owners and operators would be required to take responsive action.

Response II-14-42: EPA acknowledges the commenters' input, and the final rule requires notifications and owner, or operator reports to be submitted through the Super Emitter Portal, a website designed to take in and display timely super-emitter data. Also, while requiring multiple detections is not unreasonable and EPA believes this could be unnecessary of a single detection can be used to confirm a super emitter event.

Comment: Commenter (2453-Carbon Mapper and RMI) argue EPA should consider implementing an annual review of the GHGRP to evaluate consistency with SERP reports towards improving treatment of super emitter activity in the former.

Response II-14-43: EPA acknowledges the commenters' input; however, this effort only addresses the NSPS rulemaking.

Comment: Commenter (2453-Carbon Mapper and RMI) states EPA should encourage third-party reporters to expedite operator notification of super emitter detection. Notification timelines should account for robust quality control review that minimizes false alarms. EPA should be flexible on notification timelines in the interest of maximizing SERP participation from qualified nonprofit or research organizations whose quality control (QC) processes may be constrained by available workforce. Additionally, EPA should require that all super emitter reporting is conducted in a transparent and non-proprietary manner.

Response II-14-44: EPA acknowledges the commenters' input and in the final rule we are requiring third-party data to be provided to the EPA within 15 days of a confirmed super-emitter detection. This timeline was chosen to provide the maximum amount of time for confirmation of an event and identification of an owner or operator while being conscious that owner or operators need this information within a reasonable timeframe to conduct a successful investigation.

#### **14.4.2 Quantification**

Comment: Commenters (2184-Social Responsibility Climate Ambassador, 2345-GHGSat Inc., 2626-Kayrros) urge the EPA to leverage data from remote sensing technology to quickly identify and fix large methane leaks. The commenters applaud the EPA's strong interest in employing new tools for methane identification and quantification, particularly for super-emitters, and the EPA's creation of a regime to promote and accommodate their development and use.

Response II-14-45: EPA acknowledges the commenters' support of the Super-Emitter Program.

Commenter (2184-Social Responsibility Climate Ambassador) adds this must be required because in rural areas, 42" gas pipelines can be laid with shutoff valves that are up to 29 miles apart. By the time they are detected on the ground, they have leaked vast amounts of methane into the air, and groundwater.

Response II-14-46: EPA acknowledges the commenters' input; however, the scope of this program is limited to oil or natural gas facility subject to regulation under the NSPS OOOO, OOOOa, OOOOb, and/or under a state or Federal implementing plan of EG OOOOc.

Comment: Commenter (2410-California Office of the Attorney General et al.) suggests that EPA establish a procedure for communities to report super emitter emissions events that does not rely on the quantification of emissions. Many communities will not have access to the technologies required to quantify emissions on a kilograms-per-hour basis. The SERP should incorporate community experiences of super emitter emissions events. Communities may experience odors, health effects, and other impacts of high levels of methane and VOC emissions but may not have the resources or the ability to quantify the level of emissions. EPA should establish a pathway for community members to notify operators and the EPA of such health impacts. While notifications of odors and health impacts may not necessarily require an operator to take immediate corrective action, providing a mechanism for communities to report odor and health impacts would alert owners and operators of potential problems, and create a record of facilities that have frequent community impacts, allowing the EPA and states to identify facilities where compliance efforts should be focused.

Response II-14-47: EPA acknowledges the commenters' input. The scope of this rule is limited to approved remote sensing monitoring platforms capable of quantifying methane emissions of at least 100 kg/hr. For the purpose of this program, it is important there be some minimal quantification requirement for labeling a super emitter on part of a third-party, to trigger a response by the owner or operator.

Comment: Commenter (2458-MiQ) recommends that the report from the operator should include traceable quantification of the total emissions from super emitter event that have occurred. This will assist in recording the emissions from the super emitter event in required regulatory inventories.



Response II-14-48: EPA acknowledges the commenters' input. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility." We recognize there is benefit for the owner or operator to quantify the potential emission from a super-emitter event, it is not a requirement in this final rule.

Comment: Commenter (2294-Ohio Oil and Gas Association) requests any technology used to identify a super emitter event must be capable of quantifying the methane emissions rate without reliance on an assumed gas composition.

Response II-14-49: EPA agrees with the commenter and any remote sensing technologies used in this program must verify the measurement technology can directly quantify methane emissions.

Comment: Commenters (2218-TCEQ) argue the EPA needs to clarify the qualifications for third-party reporters in the super emitter program. The commenters agree that the qualifications of third-party reporters are important and that approved third-party reporters should show proficiency and accuracy in identifying super emitter leaks. The EPA should provide clear guidance on the requirements to obtain approval as a third-party reporter for the super emitter program. The EPA should provide draft guidance on the approval requirements for public review and comment before finalization.

Response II-14-50: EPA agrees with the commenter that the rule should expand on the requirements for those third parties seeking certification as part of the Super Emitter Program. EPA and has revised the final rule to include expanded the existing criteria for those seeking certification, these criteria can be found in §60.5371b(b) of the final rule.

Comment: Commenter (2366-BHE) argues it is imperative that any technology approved for use in the program have scientifically validated levels of performance and standard test methods developed. Any methane detection and quantification program, whether community-based or not, must include three key program components: (1) proven technology to be used to not only detect methane but accurately quantify the emission rate; (2) validated method(s) that provide a standard approach for technology use; and (3) qualification requirements or certification for users. The proposed SERP lacks these fundamental criteria.

Commenter (2366-BHE), along with other natural gas industry operators, have long supported development of new technologies to detect methane emissions. Introduction and development of OGI technology for methane leak detection was championed by industry through a Gas Research Institute (GRI) research and development program over 20 years ago. The GRI program included initial application of infrared cameras for leak detection at compressor stations and gathering and boosting facilities, and laboratory projects that evaluated OGI and other technologies, such as laser-based leak detection and quantification.

Commenter (2366-BHE) notes while (1) satellite detection, (2) remote sensing equipment on an aircraft, and (3) mobile monitoring platforms are promising technologies, they are developmental

and/or have not been through peer-reviewed demonstration programs that validate accuracy and measurement uncertainty. Nor have test methods for their use been developed and standardized. While measurement accuracy and uncertainties may be provided by technology users, those claims have not been verified via performance testing and comparison to standardized methods or defined emission rates. The commenter supports advancing these technologies, but application in a regulatory program is premature.

Commenter (2366-BHE) notes relevant methane detection and quantification technologies require standardized methods for use. That is lacking in the Supplemental Notice, which simply states that a third-party must “demonstrate technical expertise” in the three remote detection technologies.<sup>63</sup>

Response II-14-51: EPA agrees that the remote sensing technology should be validated to ensure they are able to accurately detect methane emission events at or above 100 kg/hr of methane and therefore any remote sensing technology must be approved for use under the alternative technology program in this rule. This provision in the rule requires technology providers seeking approval to develop standard methods for the operations of their measurement solutions and provide sufficient information to the EPA on their performance of these solutions in the real-world environments.

### ***14.4.3 Super-Emitter Emissions Event Detection***

#### ***14.4.3.1 Detection Methods***

Comment: Mirroring the LDAR program, Commenter (2392-Earthjustice et al.) argues EPA should not require multiple detections before owners and operators would be required to take responsive action.

Response II-14-52: EPA agrees, and the Super-Emitter rule does not require multiple detections, however the final rule now requires that the measurement technology used in this program be approved for this use to safeguard against erroneous data being submitted to the EPA.

Comment: Commenters (2220-WDEQ, 2298-Pioneer Natural Resources USA, Inc., 2326-AXPC, 2366-BHE, 2483-INGAA) contend that EPA should maintain equivalency between third-party monitoring requirements and existing standards for owners, operators, and air agency compliance staff.

Commenter (2220-WDEQ) requests that EPA require similarly stringent requirements for third-party equipment operators as those in the proposed Appendix K regulatory text. Compliance staff at agencies like WDEQ and operators must conduct OGI surveys for a minimum of 1,400 hours over the entirety of his/her career under the proposed regulations. The commenter (2220-WDEQ)

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<sup>63</sup> §60.5371b(a) and §60.5388c(a).

considers it inappropriate to allow “qualified” third parties to operate remote detection equipment under requirements that are less stringent than those that apply to states and operators.

Response II-14-53: EPA agrees with the commenters that the Super Emitter Program should include more stringent requirements for the third parties and has revised the final rule to expand the certification criteria to ensure third parties are sufficiently reviewing the super -emitter data and that the data presented to the EPA is accurate and reasonable. Likewise, the final rule requires that the measurement technology used in this program be approved for this use to safeguard against erroneous data being submitted to the EPA under the advancement alternative methane technology program, as described in §60.5398b(d).

Comment: Commenters (2298-Pioneer Natural Resources USA, Inc., 2326-AXPC) request EPA require the same level of rigor that EPA determines is required for alternative fugitive emissions monitoring and only authorize technologies that provide enough granularity to enable the third-party to identify the correct site, specific equipment or activity from which 100 kg/hr of methane is emitting. If a technology can only identify the total kg/hr of methane from the entirety of the site (*e.g.*, 25-meter x 25-meter area), the third-party would not be providing the requisite information necessary for an operator to understand whether a super emitter emissions event from an affected facility in fact exists.

Commenter (2366-BHE) is very concerned with the lack of standard methods for the example technologies EPA identifies (*e.g.*, remote or fence line monitoring technologies using laser or infrared sensors) as compared to test method requirements (*i.e.*, validated test methods) that underpin compliance determinations for NSPS or NESHAP standards. As EPA knows, an established programmatic approach has been in place for validation of compliance test methods; the SERP should be conducted with the same level of quality assurance and follow the same validation procedures.

Commenter (2483-INGAA) is very concerned with the lack of standard methods for the identified EPA technologies as compared to test method standards that have always been required by EPA for assessing compliance with a NSPS or national emission standard for hazardous air pollutants (NESHAP). A well-established programmatic approach has been in place for validation of compliance test methods, and the methods to be used in the SERP should be conducted with the same rigor to ensure the same level of quality assurance. For example, EPA has published pollutant-specific reference methods<sup>64</sup> and requirements for pollutant-specific continuous emissions monitoring specifications<sup>65</sup> for assessing compliance with NSPS and NESHAPs. EPA has also included rule-specific methods<sup>66</sup> for NSPS and NESHAPs that have undergone peer review and method validation. In this rulemaking, EPA has proposed a very

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<sup>64</sup> [See, *e.g.*,] 40 CFR pt. 60, Appendix A Reference Methods. Other EPA-approved methods include the methods promulgated or proposed by EPA’s Air Emission Monitoring Center (EMC). <https://www.epa.gov/emc/emc-promulgated-test-methods>.

<sup>65</sup> 40 CFR pt. 60, Appendix B Performance Specifications and Appendix F Quality Assurance Procedures.

<sup>66</sup> For example, a portable analyzer method for measuring carbon monoxide (CO) from natural gas-fired reciprocating internal combustion engines was adopted as Appendix A to 40 CFR pt. 63, Subpart ZZZZ (*i.e.*, the NESHAP governing Reciprocating Internal Combustion Engines).

rigorous procedure, Appendix K, for operator or service provider use of OGI technology to detect leaks at onshore natural gas processing plants.<sup>67</sup> Similar rigor must be required for methods used by third parties under the SERP, especially because those methods not only detect leaks (i.e., Appendix K is a leak detection method) but also quantify the emission rate.

Commenter (2366-BHE) provides the example, EPA has published pollutant specific reference methods<sup>68</sup> and requirements for pollutant specific continuous emissions monitoring specifications<sup>69</sup> for assessing NSPS and NESHAP compliance. EPA has also included rule-specific methods<sup>70</sup> for NSPS and NESHAPs that have undergone peer review and method validation. For this rulemaking, EPA has proposed a very rigorous procedure, Appendix K, for operator or service provider use of OGI technology for detecting leaks for a compressor station LDAR program. Similar rigor should be required for methods used by third parties under the SERP, especially because those methods not only detect leaks (i.e., Appendix K is a leak detection method) but also quantify the emission rate.

EPA also has a published procedure for validating measurement protocols: Method 301, entitled “Field Validation of Pollutant Measurement Methods from Various Waste Media.”<sup>71</sup> Section 1.0 of Method 301 defines its purpose:

Method 301 provides a set of procedures for the owner or operator of an affected source to validate a candidate test method as an alternative to a required test method based on established precision and bias criteria. These validation procedures are applicable under 40 CFR part 63 or 65 when a test method is proposed as an alternative test method to meet an applicable requirement or in the absence of a validated method. Additionally, the validation procedures of Method 301 are appropriate for demonstration of the suitability of alternative test methods under 40 CFR parts 59, 60, and 61. If, under 40 CFR part 63 or 60, you choose to propose a validation method other than Method 301, you must submit and obtain the Administrator's approval for the candidate validation method.<sup>72</sup>

The standards required for operators to validate a method should also apply to methods used for the SERP because compliance obligations for source owners and operators are contingent upon the third-party measurements. In addition, EPA had a historical process for “conditionally” approving test methods (CTMs) through the EMC<sup>73</sup> that has more recently evolved into listings of “other test methods” (OTMs)<sup>74</sup> that have been reviewed by EPA but not yet been subjected to

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<sup>67</sup> [See, e.g.,] Proposed 40 CFR §§ 60.5386b(a)(1)(i), 60.5400b(b), 60.5416b(b)(1)(B), 60.5400c(b), 60.5405c(a)(1)(i), 60.5416c(b)(1)(B).

<sup>68</sup> 40 CFR, Part 60, Appendix A Reference Methods as well as other promulgated methods at: <https://www.epa.gov/emc/emc-promulgated-test-methods>.

<sup>69</sup> 40 CFR, Part 60, Appendix B Performance Specifications and Appendix F Quality Assurance Procedures.

<sup>70</sup> For example, a portable analyzer method for measuring CO from natural gas-fired reciprocating internal combustion engines was adopted as Appendix A to 40 CFR, Part 63, Subpart ZZZZ (i.e., the RICE NESHAP).

<sup>71</sup> Method 301, Field Validation of Pollutant Measurement Methods from Various Waste Media, [https://www.epa.gov/sites/default/files/2020-12/documents/method\\_301\\_0.pdf](https://www.epa.gov/sites/default/files/2020-12/documents/method_301_0.pdf).

<sup>72</sup> [Id.] § 1.0 (What is the purpose of Method 301?).

<sup>73</sup> EPA, EMC Conditional Test Methods, <https://www.epa.gov/emc/emc-conditional-test-methods>.

<sup>74</sup> EPA, EMC Other Test Methods, <https://www.epa.gov/emc/emc-other-test-methods>.

the federal rulemaking process. Through the GRI and Pipeline Research Council International (PRCI), commenter (2483-INGAA) members have participated in projects to develop and validate CTMs and OTMs for measurement of pollutants such as NO<sub>x</sub>, CO, and formaldehyde from natural gas-fired sources. These projects were typically multi-year projects that included experimental design, field (and sometimes laboratory) testing to gather data to validate performance, and method review and approval or acceptance by EPA.<sup>75</sup> While the commenter (2483-INGAA) encourages a more expedient process and schedule for validating methane sensing and quantification test methods, similar rigor is imperative for the SERP to ensure the efficacy of third-party measurements. Because of this, it is premature at this time to implement the proposed SERP. Instead, programmatic integrity should be ensured by embarking on an effort to build the necessary “infrastructure” to confirm technology performance and develop validated test procedures. Funding available from the IRA<sup>76</sup> could be used as a resource to support development and implementation of the needed methane measurement programs.

Commenter (2366-BHE) notes EPA also has a published procedure for validating measurement protocols, i.e., Method 301, “Field Validation of Pollutant Measurement Methods for Various Waste Media.”<sup>77</sup> The introductory section of Method 301 defines its purpose:

“Method 301 provides a set of procedures for the owner or operator of an affected source to validate a candidate test method as an alternative to a required test method based on established precision and bias criteria. These validation procedures are applicable under 40 CFR part 63 or 65 when a test method is proposed as an alternative test method to meet an applicable requirement or in the absence of a validated method. Additionally, the validation procedures of Method 301 are appropriate for demonstration of the suitability of alternative test methods under 40 CFR parts 59, 60, and 61. If, under 40 CFR part 63 or 60, you choose to propose a validation method other than Method 301, you must submit and obtain the Administrator’s approval for the candidate validation method.”

Commenter (2366-BHE) states the standards required for operators to validate a method should also apply to methods used for the SERP because compliance obligations for owners and operators are contingent upon the third-party measurements. In addition, EPA had a historical process for “conditionally” approving test methods (CTMs)<sup>78</sup> through its Emission Measurement Center, which more recently evolved into listings of “other test methods” (OTMs)<sup>79</sup> that have been reviewed by EPA but not yet subjected to the federal rulemaking process. Through the GRI and Pipeline Research Council International (PRCI), INGAA members have participated in projects to develop and validate CTMs and OTMs for measurement of pollutants such as NO<sub>x</sub>,

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<sup>75</sup> [See, e.g.,] CTM-037 (finalized as Method 323), <https://www.epa.gov/sites/default/files/2016-07/documents/m-323.pdf>; OTM-39, [https://www.epa.gov/sites/default/files/2020-08/documents/otm-39\\_performance\\_method\\_using\\_portable\\_gas\\_analyzers\\_08\\_24\\_2020.pdf](https://www.epa.gov/sites/default/files/2020-08/documents/otm-39_performance_method_using_portable_gas_analyzers_08_24_2020.pdf).

<sup>76</sup> The IRA includes various funding sources, including the Section 60113 methane emissions reductions program, which includes \$850 million in funds through 2028 to support facility methane reporting under the GHGRP (40 CFR pt. 98, Subpart W), methane emissions monitoring, and methane mitigation from natural gas systems. IRA of 2022, 136 Stat. 2305, Pub. Law No. 117-169 § 60113 (Aug. 16, 2022).

<sup>77</sup> [https://www.epa.gov/sites/default/files/2020-12/documents/method\\_301\\_0.pdf](https://www.epa.gov/sites/default/files/2020-12/documents/method_301_0.pdf).

<sup>78</sup> <https://www.epa.gov/emc/emc-conditional-test-methods>.

<sup>79</sup> <https://www.epa.gov/emc/emc-other-test-methods>.

CO and formaldehyde from natural gas-fired sources. These projects were typically multi-year projects that included experimental design, field (and sometimes laboratory) testing to gather data to validate performance, and method review and approval or acceptance by EPA. While INGAA encourages a more expedient process and schedule for validating methane sensing and quantification test methods, similar rigor is imperative for the super emitter technological program to ensure the efficacy of third-party measurements. Because of this, it is premature to implement the proposed program at this time. Instead, programmatic integrity should be ensured by embarking on an effort to build the necessary “infrastructure” to confirm technology performance and develop validated test procedures. Funding available from the IRA<sup>80</sup> could be used as a resource to support development and implementation of the needed methane measurement programs.

Commenters (2222-Wisconsin Department of Natural Resources 2238-Southeastern Ohio Oil and Gas Association (SOOGA), 2294-Ohio Oil and Gas Association, 2399-GPA Midstream Association) request EPA provide methods and guidance for detecting super emitter emissions events.

Commenter (2222-Wisconsin Department of Natural Resources) states that EPA proposes to allow the use of remote-sensing aircraft, mobile monitoring platforms, or satellites to identify super emitter emissions events. Commenter recommends EPA test and recommend monitoring methods, guidance and standards for states to use to define super emitter emissions events.

Response II-14-54: EPA agrees with the commenters and the final rule now requires that the measurement technology used in this program be approved for this use to safeguard against erroneous data being submitted to the EPA. The requirements for this approval are the same requirements in the alternative technology program in this rule which is consistent if not more demanding than EPA’s existing alternative test method programs.<sup>81,82</sup>

Comment: Commenter (2483-INGAA) states that once a methane detection program has identified the relevant technologies, guidance then needs to be given regarding how that technology must be deployed. The proposed regulatory text provides no information on how these technologies should be used. It simply specifies that a third-party must “demonstrate [] technical expertise” in the three remote detection technologies.<sup>83</sup>

Response II-14-55: EPA agrees with the commenters and the final rule now requires that the measurement technology used in this program be approved for this use through the advancement

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<sup>80</sup> IRA includes various funding sources, including the Section 60113 methane emissions reductions program, which includes \$850 million in funds through 2028 to support facility methane reporting under the GHG Reporting Program (40 CFR, Part 98, Subpart W), methane emissions monitoring, and methane mitigation from natural gas systems.

<sup>81</sup> 40 CFR 60.8(b).

<sup>82</sup> 40 CFR 63.7(e).

<sup>83</sup> Proposed 40 CFR §§ 60.5371b(a), 60.5388c(a).

alternative methane technology program, as described in §60.5398b(d), to safeguard against erroneous data being submitted to the EPA.

Comment: Commenter (2483-INGAA) notes that the proposed program, as written, defines a super emitter based on an hourly rate but does not specify that the technology must measure a statistically significant period to determine that an emissions event exceeds the hourly rate. For example, a third-party could measure an emission rate of 1.7 kg/min for 3 minutes and draw the conclusion that the source exceeds 100 kg/hr (i.e., 1.7 kg/min x 60 mins = 102 kg/hr). In reality, however, this source could be a single, short-term blowdown event (e.g., a compressor blowdown) lasting several minutes with total emissions far less than 100 kg/hr and not constitute a “super emitter” event. These short-term blowdown events can be associated with necessary and regular operational practices and/or emergency shutdown procedures. It is imperative that this program include proof that the emission source is persistent (e.g., an ongoing large leak), and the time element and/or cumulative emission total should be defined before a third-party can issue a notice to the owner or operator of a source.

Response II-14-56: EPA disagrees with the commenter that super emitter events must be proven as persistent. EPA recognizes that these events are infrequent and may be intermittent, however the intent of this additional monitoring effort is to identify this emission when they happen so the cause can be investigated.

Comment: Commenter (2238-SOOGA, 2294-Ohio Oil and Gas Association) states that notwithstanding U.S. EPA’s questionable legal authority for establishing the SERP, the regulatory framework for the program needs further development. The commenter (2294-Ohio Oil and Gas Association) suggests that U.S. EPA initiate the rulemaking process to approve each technology used by the third-party detectors so that industry has an opportunity to comment on the merit of each technology. The Supplemental Proposal does not provide adequate detail for stakeholders to provide comments as it only identifies the technology by name with no information about the technology and its limitation. Similarly, U.S. EPA should develop detailed criteria for the certification of qualified third-party detectors for public review and comment.

Commenter (2399-GPA Midstream Association) urges EPA to develop and impose criteria on the third-party detection technologies that may be used under any SERP. At present, the proposal offers no criteria, leaving room for third-party detection equipment that is not reliable, and thus, could be used to compel another private party to invest substantial time and resources unnecessarily, as well as to create a public perception regarding an industry entity that is unfair and unjustified. Before finalizing these new criteria, EPA should make the proposed criteria available for public comment, as required by the APA.

Response II-14-57: EPA thanks the commenter for their input and has expanded that criterion in the final rule. EPA does not consider it necessary that these expanded criteria are subject to additional public comment because the final rule no longer includes the third-party contacting the owner or operator. Instead, with the super-emitter notifications being sent to EPA, these criteria are to improve the quality of the information being provided to the EPA and EPA has the final decision on whether this super-emitter data is actionable.

Comment: Commenter (2399-GPA Midstream Association) recommends EPA require approved third parties to implement and document protocols established by equipment manufacturers for how they calibrate, use and regularly maintain detection equipment in a fashion similar to proposed Appendix K, which includes exceptionally detailed proposed mandates for OGI use (from maximum wind speeds to operator break times). Yet, as framed in the proposal, EPA appears to allow for approval of third-party detection equipment upon the barest showing of theoretical functionality – a standard that EPA does not follow for monitoring or compliance monitoring generally. New test methods or monitoring techniques must go through rigorous review by technical experts and public scrutiny before EPA allows their use – and often not until the technology or the technique has first gone through lengthy testing and review by knowledgeable standards setting bodies, such as ASTM and others. This type of rigor should be applied to any technology that would be used for a proposed program, along with a public process for review and comment on the technology. Any less rigorous approach would, again, not only lack credibility – but would arbitrarily impose requirements on industry that it would not impose on those bringing quasi-enforcement actions against industry.<sup>84</sup>

Additionally, the commenter (2399-GPA Midstream Association) notes that where EPA has provided general descriptions of technologies that would be allowed under this proposed program, the draft regulatory text - specifically the categories of “Satellite detection of methane emissions,” “Remote-sensing equipment on aircraft,” and “Mobile monitoring platforms” – highlights the need for EPA to consider these technologies and their use further, offer a more detailed regulatory proposal, and allow for public input. Proposed §§ 60.5371b(a)(1)-(3).

First, commenter (2399-GPA Midstream Association) provides that the proposed text conflates the concepts of detection and quantification. All of the listed categories of technologies involve remote sensing technologies that detect methane emissions – but they do not directly measure emissions. At most, these technologies may rely on proprietary algorithms to estimate remotely sensed concentrations (commonly expressed in ppm-m) and convert those into a mass emissions rate (such as kg/hour). EPA should recognize that these technologies can only provide a rough estimated emissions rate. They do not provide a “quantified emission rate” as the proposed text asserts. See Proposed §§ 60.5365b(j), 60.5371b, 60.5371b(b)(4), 60.5371b(e)(ii)(D).

Second, commenter (2399-GPA Midstream Association) states that while these technologies (if properly calibrated, operated, and maintained) may be able to detect methane emissions, each of

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<sup>84</sup> Although the commenter (2399-GPA Midstream Association) views the SERP as unlawful under both Section 111(b) and 111(d), EPA appears to believe that the program also will be applied to existing sources through Section 111(d) state plans. See 87 Fed. Reg. at 74,753 (stating that most super emitters would be violating “the proposed NSPS OOOOb/EG OOOOc.”). The Supplemental Proposed Rule never addresses how EPA will evaluate state plans implementing the SERP and the discretion state agencies may have in approving third-party notifiers and the detection technologies they use. EPA should not apply this program to existing sources unless and until it addresses these and other issues regarding extending this program in a separate proposal subject to public comment.



these technologies have documented accuracy limitations.<sup>85</sup> EPA has provided no independent evaluation or other rationale for accepting the listed technologies as accurately detecting methane to a degree that they may be used as tools to compel investigations and corrective actions by affected facility owners and operators. Further, as noted above, it does not appear that EPA plans to impose any protocols on how these technologies are used or their results interpreted. For example, if the technology's field study data shows an error in emission estimates that ranged from -50% to 100%, a measurement should only be valid as it relates to this program if it is still over the 100 kg/hr threshold assuming the potential error. These types of nuances in data interpretation need to be thoughtfully considered and explained. OGI cameras are comparatively mature technologies, yet EPA would use proposed Appendix K to impose restrictive mandates on how they are used, and who may use them. The absence of any similar protocols for the technologies in Proposed §§ 60.5371b(a)(1)-(3) not only undermines confidence in their use, but effectively implements an arbitrary “no rules” policy for these technologies.

Accordingly, to improve the confidence in use of these technologies, the commenter (2399-GPA Midstream Association) recommends EPA create a detailed protocol through which these technologies prove their accuracy (including maintenance and calibration requirements) and provide assurance that changes made to proprietary algorithms are not made without agency approval. Further, in view of inherent limitations with certain technologies (e.g., satellite/aerial detection capability is limited due to weather conditions), EPA should specify conditions under which these technologies are suitable for emissions detection.

Third, the commenter (2399-GPA Midstream Association) considers the term “mobile monitoring platform” vague. EPA should provide the public with fair notice of exactly what platforms may be qualified for use by third-party notifiers and proffer specific guidelines on how each of the defined set of platforms may be used to support a notice under this program.

Response II-14-58: EPA acknowledges the commenters' input. A detailed process by which EPA will approve the use of specific technologies and approaches is included in the final rule. Similarly, the final rule includes requirements on the user of these technologies to develop performance criteria and data quality requirements to be met as part of the operation of these approaches, which will be evaluated and approved by the EPA.

Comment: Commenters (2258-MS, 2391-Chesapeake Energy Corporation (CEC)) provide that EPA should ensure that any technology used by third parties to monitor affected facilities under this proposed program meets the same requirements EPA has proposed for alternative technologies for periodic screening of fugitive emissions.

Response II-14-59: EPA agrees with the commenter and the final rule now includes the requirement that any remote sensing technology used in the super-emitter program must be

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<sup>85</sup> The tools used to evaluate an emissions event have error bars for a single “measurement” ranging from +/- 17% at the most accurate end to +/- 70% for the types of events that occur in the field. Heltzel, R., et al., Understanding the Accuracy Limitations of Quantifying Methane Emissions Using Other Test Method 33A, *Environments* 2022, 9, 47, <https://doi.org/10.3390/environments9040047>; Halley L., et al., Assessment of Methane from Oil and Gas Production Pads Using Mobile Measurement, *Env't'l Sci. & Techn.* 2014 48 (24), 14508-14515.

approved under the alternative test method provision in the rule as found in § 60.5398b(d) in the final rule.

Comment: Commenter (2284-Kairos Aerospace) highlights a recently released preprint publication, “Quantifying oil and natural gas system emissions using one million aerial site measurements” by Sherwin et al. (Under review at Nature) establishes basin-scale emission estimates from fifteen survey campaigns (including the two campaigns described by Cusworth and Chen) across six producing basins.<sup>86</sup> Although still undergoing peer review, this study is unparalleled in its scope, making use of 1 million aerial measurements— a factor of ten greater than the previously mentioned studies. This study examines six basins: Permian (several surveys), San Joaquin, Denver-Julesburg, Marcellus (partial Appalachia focused on a high production region of Pennsylvania), Uinta, and Barnett. It leverages data from two airborne survey providers, Kairos Aerospace and Carbon Mapper, covering 15 airborne campaigns. Critically, the study’s methodology merges top-down airborne surveys with bottom-up emissions modeling specific to asset inventories and surveyed area production of each basin (based on the model of Rutherford et al., 2021) to develop a full emissions distribution for each basin (site-level).<sup>87</sup> This includes modeled emissions below the minimum detection limit of the airborne technologies. The resulting distributions can be used to quantify full basin loss and assess the effectiveness of airborne detection strategies at the basin scale.

The study presents several key findings:

- Sites with aerially-detectable emissions are rare but even more impactful than previously understood— “Aerially measured emissions at 0.05%-1.4% of well sites contribute 51%-81% of total emissions in twelve of fifteen campaigns.”
- Surveyed regions in this study contribute an estimated 6.3 million t/yr of methane emissions, equivalent to total greenhouse gas emissions from France.
- Basin-level methane loss rates vary significantly, but all campaigns with greater than 80% basin coverage (n=11) quantified a loss rate greater than the EPA GHG inventory estimated loss rate.
- Basin-level loss rates can vary over time.

Commenter (2284-Kairos Aerospace) argues this study further strengthens EPA’s footing for using advanced leak screening techniques as a part of its proposed matrix and as part of the scientific underpinning for the SERP. It also provides some of the very first, basin-scale evidence that these large sources of emissions are not a Permian-only phenomenon. It also raises the question of why, through its FEAST modeling, EPA would disadvantage these same advanced screening technologies by biasing model outputs in favor of OGI. As Dr. Robert Kleinberg of Columbia University observed, EPA’s own greenhouse gas inventory shows “[M]ethane emissions have changed little over the years following promulgation of the OOOO rules,

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<sup>86</sup> Sherwin et al. “Quantifying oil and natural gas system emissions using one million aerial site measurements” <https://www.researchsquare.com/article/rs-2406848/v1> 2023 In Revision.

<sup>87</sup> Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P., Heath, G.A., Englander, J., Cooley, D., Lyon, D., Omara, M., Langfitt, Q., Brandt, A.R., 2021. Closing the methane gap in US oil and natural gas production emissions inventories. Nat Commun 12, 4715. <https://doi.org/10.1038/s41467-021-25017-4>

consistent with a long-term annual decline rate of about 0.3 percent.”<sup>88</sup> Clearly, the traditional OGI-based leak detection program being established as BSER leaves opportunity for improvement. Advanced leak screening technology has been instrumental in shaping our understanding of methane emissions, and ought to be instrumental in our plans to reduce methane emissions.

Response II-14-60: EPA acknowledges the commenters’ input.

Comment: Commenter (2333-LongPath Technologies, Inc.) contends that there is no inherent reason to limit the use of any type of technology for applying to be a super emitter program participant. The limitation of technology types in the final rule will only risk stifling future technology improvements and innovations. For example, there is no fundamental reason to exclude fixed or ground-based technologies by providing a prescriptive and limited list, provided the approval requirements clearly ensure the safety of all participants. Commenter requests more information justifying this level of technology-specificity or for this requirement to be removed.

Response II-14-61: EPA acknowledges the commenters’ input. Ground-based remote sensing is an option in the rule, our intent in limiting the technology to remote sensing technology was to ensure the public was not seeking to access to well-sites out of a concern for security and safety.

Comment: Commenter (2389-ACC) notes EPA solicits comment on its proposed technology types for conducting monitoring on the program, i.e., “remote-sensing aircraft, mobile monitoring platforms, or satellites” to identify potentially relevant events.<sup>89</sup> Commenter (2389-ACC) believes that the reliability of monitoring programs depends on the quality and accuracy of the collected data and the knowledge and expertise of the persons operating the program.

As such, the commenter (2389-ACC) states it is critically important that EPA ensure that the new programs’ emissions data is accurate, reflective of current conditions, and relevant to the overall program’s purpose. As a technical matter, the Agency should also ensure that the monitoring instruments and equipment that collect the data are of high scientific and technical integrity. That is, EPA should require that the instruments are in good working order and are properly calibrated and maintained according to the manufacturer’s specifications.

Additionally, the commenter (2389-ACC) recommends EPA ensure that any personnel involved in the collection, analysis, and ongoing maintenance of the super emitter monitoring program is appropriately qualified and trained to execute these types of technical programs. Specifically, the commenter (2389-ACC) recommends that EPA ensures that staff from approved third parties that may be involved in the operation of monitoring equipment (e.g., citing, calibration, standard maintenance, etc.) or in the handling of monitoring data (e.g., collection, interpretation, communication, etc.) who have relevant experience in monitoring programs, as well as some

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<sup>88</sup> Kleinberg, Robert L., “Methane Emission Controls: Redesigning EPA Regulations for Greater Efficacy,” Columbia University Center on Global Energy Policy, October 4, 2021, <https://www.energypolicy.columbia.edu/research/commentary/methane-emission-controls-redesigning-epa-regulations-greater-efficacy>

<sup>89</sup> 87 FR 74749.

level of practical experience and training against applicable technical, procedural, and quality assurance standards. Without properly trained personnel using operational equipment to collect accurate emissions information, EPA risks the creation of monitoring programs that generate and present flawed information and conclusions.

Commenter (2389-ACC) also notes that EPA's proposed technology types for monitoring under this program appears to signal that the Agency is requiring that qualifying technologies meet at least some level of QA/QC requirements associated with air monitors (rather than air sensors). The commenter (2389-ACC) supports this approach since more scientifically sound monitoring technologies are more likely to provide reliable, actionable information for both facilities and the communities in which they operate. The commenter (2389-ACC) further recommends that EPA carries forward a similar approach for criteria and qualifications for its proposed and future programs that will be administered with funding provided by the IRA. Many IRA programs would launch air monitoring initiatives supported by EPA funding, which will also be conducted by parties external to EPA and the regulated community. However, at this stage, it is unclear whether the IRA-funded air monitoring programs would contain the same standard of credibility for the monitors used. As such, the commenter (2389-ACC) strongly encourages the Agency to create similar criteria for the data collection and dissemination of air monitoring conducted under IRA programs.

Response II-14-62: EPA acknowledges the commenters' input. EPA agrees with the comment that methane detection technology used for this program should be in good working order and that third parties reviewing the results should be adequately trained. The final rule now includes criteria that technology and procedures for operating the technology used as part of the Super-Emitter Program be pre-approved by the EPA. Likewise, the final rule includes criteria that third parties operating be sufficiently trained on the operation of the technology used to determine whether data is supported enough to submit to the EPA.

Comment: Commenter (2483-INGAA) supports the development of new technologies to detect methane emissions. Commenter (2483-INGAA) contends its members were instrumental in the development of infrared camera technology (i.e., OGI) for methane leak detection, with pipeline operators working in conjunction with GRI projects over 20 years ago. These projects included the initial application of infrared cameras for leak detection at natural gas facilities and culminated in EPA adopting an alternative work practice for OGI,<sup>90</sup> including OGI for leak surveys required under Subpart W of the GHGRP at compressor stations and other natural gas facilities.<sup>91</sup>

While the commenter (2483-INGAA) has long supported the development of new technologies for methane emission detection, those technologies cannot be used to trigger compliance requirements until the technology has been proven to be a reliable indicator of methane leaks. In the Supplemental Proposed Rule, EPA proposes that the following remote detection technologies would be approved for use by third parties in the proposed SERP: (1) satellite detection; (2)

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<sup>90</sup> 40 CFR § 60.18(i).

<sup>91</sup> Id. § 98.234(a)(1).

remote sensing equipment on an aircraft; and (3) mobile monitoring platforms.<sup>92</sup> Commenter (2483-INGAA) members are advocates for advancing these technologies, but do not believe that they have yet reached the threshold needed to be part of a regulatory program that gives rise to legal obligations by the owners and operators of covered sources – even a program that is designed as a “backstop” measure.<sup>93</sup> For example, while the users and manufacturers of these technologies may claim these new remote detection technologies provide accurate results, these claims have not been verified via performance testing and comparison to standardized methods or defined emission rates. Nor have these claims been peer reviewed and published. Indeed, results from some initial tests show that while leak detection is possible, very large uncertainties and inaccuracies are common for quantified measurement of leak rates.

For example, commenter (2483-INGAA) notes that the 100 kg/hr threshold for the SERP is similar to the detection limit claimed for satellite technology. A 2021 presentation on this technology indicates, however, that there is significant measurement uncertainty – even when data analysis techniques average many measurements over an extended period rather than relying on a point in time measurement. The proposed SERP does not consider emissions “persistence” or the time duration of the event when determining whether a source is a super emitter.

Commenter (2483-INGAA) describes a figure [Figure 1] showing data presented at the 2021 EPA Methane Workshop by Riley Duren regarding a gathering line leak that was first detected utilizing aircraft surveys at altitudes of approximately 18,000 feet.<sup>94</sup> Over the following week, eight additional surveys were conducted. Follow up to these detections included extensive investigation to determine the leak source, with eight organizations involved in the effort. Figure 1 shows methane emissions hovering around 100 kg/hr (i.e., the proposed threshold for the SERP), with 50% or higher uncertainty in the reported results. In addition, the reported data are averages of multiple measurements, which will dampen uncertainties. Uncertainty for individual measurements is unclear but surely higher.

[Chart of Daily Average Emission rate (kgCH<sub>4</sub>/hr) described in paragraph above]

Figure 1: Example of variation in average satellite emission rate measurements<sup>95</sup>

Commenter (2483-INGAA) also notes that the literature indicates that wind conditions, temporal changes in emissions, and the quantification algorithm can significantly affect measurement results. Measurement duration and data compilation (e.g., averaging multiple measurements) are relevant issues. Remote technology measurements are typically of short duration, and such point in time measurements may not be representative of hourly average emissions (e.g., a remote technology measurement may include an intermittent process gas release event). Thus, researchers often compile many measurements and present an average to show performance

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<sup>92</sup> 87 Fed. Reg. at 74,749.

<sup>93</sup> Id. at 74,747.

<sup>94</sup> Riley Duren, University of Arizona, “Towards a Multi-Scale Methane Monitoring System of Systems” (Aug. 24, 2021), <https://www.youtube.com/watch?v=IQcUhMG24X0> (Mr. Duren’s presentation begins at 5:05 and runs through 5:26).

<sup>95</sup> Id.

versus actual emissions. For example, hundreds of thousands of measurements are averaged over days to years to overcome the temporal challenges.<sup>96</sup> This data manipulation is an example of why defined methods are needed for third-party measurements and applying this “technique” in published studies hinders the ability to discern uncertainty of individual measurements that are not precluded in the Supplemental Proposed Rule.

Furthermore, commenter (2483-INGAA) states wind speed and direction can vary when measurements are being taken and impact the accuracy of remote technology measurements. For satellite measurements, Jacob et al. note “weak winds facilitate detection but cause large error in quantification.”<sup>97</sup> Without defined methods, these influences will not be accounted for by third-party measurements.

Commenter (2483-INGAA) continues in stating that if the wind is measured, uncertainty is introduced by the type of wind meter utilized. Kairos Aerospace’s airplane-based hyperspectral imaging methane emissions detection system reports factors that affect uncertainty from a study with blind controlled releases of methane ranging from 18 to over 1,025 kg/hr.<sup>98</sup> The study notes that wind speed and measurement method can impact results, including the type of instrument used to measure wind speed. This is an example of why defined methods (discussed below) are needed for implementation of technology within any leak detection program. Significant uncertainty in the results was also reported. Data reported from other studies with lower leak rates (e.g., remote sensing of distribution leaks in urban areas) also show significant uncertainty (i.e., in excess of 100% and much higher for lower leak rates).<sup>99</sup>

In sum, while peer reviewed publications are limited, Commenter (2483-INGAA) believes available information shows high uncertainty in remote quantification of leak emission rates, analysis methods that consider averages of many measurements when comparing remote measurements to actual emissions, and influences from parameters like wind speed. These issues clearly show the need for quality control and defined methods for applying remote detection technologies.

Response II-14-63: EPA acknowledges the commenters’ input. Providers submitting request to the EPA to have their methane detection approved would be required to determine submit supporting information to determine under what conditions they may be operated and developed

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<sup>96</sup> E.D. Sherwin, et al., “Single-blind validation of space-based point source methane emissions detection and quantification” (Aug. 14, 2022) (pre-print, not peer-reviewed, submitted to EarthArXiv), <https://www.eartharxiv.org/repository/view/3465>.

<sup>97</sup> D.J Jacob, et al., “Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane” (July 29, 2022), *Atmos. Chem. Phys.* 22, 9617-9646, 2022, <https://acp.copernicus.org/articles/22/9617/2022/acp-22-9617-2022.pdf>.

<sup>98</sup> E.D. Sherwin, et al., “Single-blind test of airplane-based hyperspectral methane detection via controlled releases” (2021), *Elementa: Science of the Anthropocene*, <https://online.ucpress.edu/elementa/article/9/1/00063/116576/Single-blind-test-of-airplane-based-hyperspectral>.

<sup>99</sup> SoCalGas, Aerial Methane Mapping Research Update: Best Practices 17 & 20a, SB-1371 Winter Workshop (Jan. 21, 2021), [https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/day-2-slide-1---sempra---bp17\\_20a---aerial-methane-mapping-randd---sempra.pdf](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/documents/day-2-slide-1---sempra---bp17_20a---aerial-methane-mapping-randd---sempra.pdf).

QA/QC consistent with how a technology must be operated to ensure the technology provides data that are of high quality.

#### 14.4.3.2 Advanced Technology

Comment: Commenter (2256-Mille Lacs Band of Ojibwe) believes to achieve prompt mitigation and further increases accountability EPA should encourage innovative and advanced monitoring technologies and leverage qualified expert monitoring to identify "super emitters."

Commenter (2458-MiQ) recommends that instead of identifying technologies for the SERP, EPA should use a technology agnostic approach. EPA should include all monitoring requirements and then approve technologies that meet those requirements. These might include methane detection limit (MDL) parameters and a required safe distance from the source, for example.

Response II-14-64: EPA acknowledges the commenters' input, and the final rule includes a provision that technology used in the super-emitter program must be approved by the EPA.

Comment: Commenters (2433-EDF et al., 2626-Kayros) argue remote sensing technologies bring a much-needed transparency to the program because they can be deployed by independent third parties, and in most cases their results can be made publicly available. Another key advantage is the broad geographical coverage they provide, given the highly dispersed nature of super emitters across the entire energy supply chain.

Response II-14-65: EPA acknowledges the commenters' input.

Comment: Commenter (2433-EDF et al.) supports EPA's proposed technological parameters and the requirement that technologies be capable of quantifying an emission flux of 100 kg/hr or greater. However, the commenter urges EPA to not overly restrict the technologies that may qualify. EPA should use the alternative test method approval process already under development to approve technologies for use in SERP. To do this, EPA would need to add an additional quantification criterion for SERP technologies, but otherwise may rely on the same procedures. Commenter (2433-EDF et al.) generally believes the technologies EPA has specified for SERP in the supplemental proposal are appropriate, but there may be additional technologies that could operate within the requirements of this program that are excluded by including a limited list. For example, tower-based systems that can quantify emissions, if approved by EPA, should also be allowable under SERP.

Commenter (2433-EDF et al.) urges EPA to not impose more onerous requirements on technologies used for SERP than those used under the LDAR program, aside from the quantification requirement. Qualified third parties should not face a higher barrier to monitoring than operators themselves do, especially because third-party data will be more objective and potentially more accurate than data submitted by operators who may face conflicts of interest in accurately reporting their own emissions and violations. And with a 100 kg/hr detection requirement, there is no need for permissible technologies to be vetted in more depth than

technologies deployed for the LDAR program which must be able to detect much smaller emissions sources.

Response II-14-66: EPA acknowledges the commenters' input. EPA agrees that we should play a role in approving technology used in the Super Emitter Program, and in order to be consistent in are approach, is using the same criteria for technology used in Advanced Methane Detection Technology Program for fugitive component and covers and CVS monitoring.

Comment: Commenter (2198-University of Denver College) says that the need to incorporate modern technologies is going to be curtail for the future of monitoring oil and gas sites. Methane concentrations can vary greatly depending on the location and monitoring that needs to be conducted in many different areas to get a comprehensive understanding of emissions. "More than 26 million acres of federal land, an area comparable to the size of Kentucky, are currently under lease for oil and gas drilling. (Adler, 2022) The EPA is proposing a SERP where an owner or operator must investigate and take appropriate mitigation actions upon receiving certified notifications of detected emissions that are 100 kg/hr of methane or greater. Commenter (2198-University of Denver College) thinks at the scale of potential new sites, this will become ineffective and have potential for corruption.

Commenter (2198-University of Denver College) expresses that the challenges of monitoring methane can make it difficult to obtain a comprehensive understanding of methane emissions and to develop effective strategies to mitigating them. An all-encompassing approach to every site would have more effective results towards monitoring methane. "Thanks to powerful technologies, such as high-resolution satellite data, scientists are now able to underline the impact of frequent and intentional methane releases, also known as venting.<sup>100</sup>" Each satellite can measure any site in the world every two weeks.<sup>101</sup> This would also allow for each site to measure under the same measuring standards. This technology should be considered in an all-encompassing methane monitoring effort. As this technology would have great advantages in the new quarterly monitoring being proposed.

Response II-14-67: EPA acknowledges the commenters' input. The Super-Emitter Program is not intended to replace the existing monitoring programs in the rule and is designed to supplement those other efforts under the guide of providing actionable information (*i.e.*, EPA verified super-emitter) to owner or operators in an effort to further reduced methane emissions from this sector.

Comment: Commenters (2284-Kairos Aerospace, 2333-LongPath Technologies, Inc., 2440-Nevada Nanotech Systems, Inc.) argue continuous monitors should be incentivized because they provide time history of emissions on sites that receive super emitter event program alerts. Continuous monitoring solutions provide the most rapid detection and therefore the greatest abatement of emissions.

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<sup>100</sup> European space agency, 2021.

<sup>101</sup> EPA, 2018.



The EPA suggests, on page 74754, that “the more targeted SERP would thus be a more effective solution for addressing sporadic, large emission events that may occur outside the periodic... monitoring.” Commenter (2333-LongPath Technologies, Inc.) takes the intent of the super emitter program, therefore, to indicate the EPA does not believe that the proposed periodic screening survey approaches (OGI, alternative technology) are sufficient to rapidly address super emitters, which can contribute disproportionately to overall emissions from oil and gas.

Commenter (2333-LongPath Technologies, Inc.) therefore suggests that EPA formulate stronger incentives for operators to use continuous monitoring, which would achieve orders of magnitude higher emissions reductions with more rapid find-and-fix across a larger set of assets than can be achieved by periodic screening via the matrices or random screening by a voluntary, 3rd-party watch-dog program.

Specifically, Commenter (2333-LongPath Technologies, Inc.) suggests that EPA create specific exemptions from parts of the super emitter program response requirements for those sites that employ quantitative continuous emissions monitoring with ability to monitor all equipment on site (e.g., stick flares, tall tanks, yard piping). The commenter strongly recommends that EPA allow those operators who have valid quantification continuous monitors with full-site coverage on a site to use that data to respond to super emitter program alarms. Commenter (2333-LongPath Technologies, Inc.) further recommends that sites with continuous monitors installed be exempt from the public-reporting portions of the program, since it is extremely likely they will already have responded to and repaired the reported leaks by the time of posting. Operators should therefore not be penalized for having appropriately and immediately responded to fugitive emissions through their voluntary use of continuous monitoring data.

Commenter (2333-LongPath Technologies, Inc.) notes as EPA suggests, on page 74754, that “the more targeted SERP would thus be a more effective solution for addressing sporadic, large emission events that may occur outside the periodic OGI monitoring.” The commenter takes the intent of the super emitter program, therefore, to indicate the EPA does not believe that the proposed OGI and AVO BSER is sufficient to rapidly address super emitters, which can contribute disproportionately to overall emissions from oil and gas. It is unclear how comprehensive the coverage of US producing basins will be under this voluntary, 3rd party program. By contrast, there are dozens of high-TRL continuous monitoring technologies capable of rapidly scaling to cover the entirety of US production, given sufficient operator incentivization to participate in a continuous monitoring program. Continuous monitoring could certainly be said to “be a more effective solution for addressing sporadic, large emission events that may occurs outside the periodic OGI monitoring”.

Response II-14-68: EPA acknowledges the commenters’ input. The detailed criteria for super emitter detection and technology approval are defined in the final rule and is technology agnostic, meaning anyone, including the commenter can be approved if they can meet the criteria.

Regarding the use of continuous emissions monitoring in the Super-Emitter Program, we would expect these systems would identify these large emissions far sooner than any potential super-

emitter emission event however we disagree the use of these systems would limit the obligation to report these events, in the event an emission event was reported to an effective owner or operator. However, continuous emissions systems would be invaluable in determining whether these events occurred or are still recurring and the data from these systems (if available) could be used to aid in responding to super-emitter notifications.

Comment: Commenter (2284-Kairos Aerospace) argues it makes little sense to require operators to conduct ground visits solely based on third party reports. This adds significant operational complexity, risk, and cost, and would not be strictly necessary to evaluate the incoming report. Since the SERP is built on remote sensing data, it follows logically that operators should be able to use remote sensing technology to respond to incoming reported detections. Any remote sensing technology used for compliance purposes will already have detection limits well below 100 kg/hr, making them capable of detecting a super emitter event.

Commenter (2284-Kairos Aerospace) states by allowing remote sensing technology to be used to investigate reported emissions, EPA will give operators flexibility, reduce operational disruption, and improve the safety of the Response Program. Since vehicle accidents are a leading cause of oilfield fatalities, creating an urgent trip out into the field for a ground crew poses a potential safety risk. Further, if there is a super emitter, putting ground crews in close proximity more than strictly necessary to make repairs should also be avoided.

Commenter (2284-Kairos Aerospace) envision a program where if a super emitter is reported to an operator, they could use available remote sensing data to evaluate the emission or deploy remote sensing technology quickly to evaluate. If emissions are confirmed by the operator's remote sensing survey, only then would ground crews be dispatched for repair. This could work in two ways:

Scenario 1: An operator receives a report from a third party about a super emitter event it detected two weeks ago in a routine survey. That operator did its regular leak survey one week ago using a remote sensing technology, which detected no emissions. The operator could then dismiss the reported super emitter as unconfirmed through follow-up.

Scenario 2: An operator receives a report from a third party about a super emitter event it detected in a routine survey. Upon receipt of the third-party report, the operator dispatches a remote sensing survey to be conducted within the specified investigation time frame. If the emissions are identified in that second remote sensing survey, the operator takes appropriate corrective action. If emissions are not detected, the operator could then dismiss the reported super emitter as unconfirmed through follow-up.

Response II-14-69: EPA acknowledges the comment, the final rule includes allowance to use existing continuous monitors data or fugitive monitoring surveys conducted after the identified super-emitter event and the notification event to determine the presence of the super-emitter event.

Comment: Commenter (2202-TXOGA) states that if a final rule includes third-party monitoring under a Super emitter Program,<sup>102</sup> EPA should consider several issues related to approval of technologies. First, Commenter (2202-TXOGA) agrees with the suggestion of a focus on remote monitoring technologies that do not need site access. In particular, aircraft and satellites, which have been used by third parties in Texas, are likely safer options than ground-based technologies. Second, technologies must be able to provide timely information and quantification. Information received several months after a detection will likely be challenging for operators to utilize effectively, so EPA should provide that third parties must provide data to operators within the same timeline to which operators are held for periodic screenings. Third, EPA should create performance requirements around geolocation abilities, including the ability to locate to a specific site and, ideally, a specific piece of equipment. Technologies that provide only regional data that may include multiple sites and operators or are subject to non-public atmospheric modeling assumptions will be difficult for operators (and regulators) to interpret and may lead to a significant expenditure of resources without corresponding emission reductions. Fourth, all measurement techniques include uncertainty ranges on quantification that should be known and required to be disclosed by the measurement provider.

Response II-14-70: EPA acknowledges the comments, the final rule now includes provisions consistent with these comments, including EPA approving technology, super-emitter data must be submitted within 15 days of an event, and requirements for what information must be submitted to the EPA (e.g., lat/long, mass emission uncertainty).

Comment: Commenters (2345-GHGSat Inc., 2457-Providence Photonics, LLC) understand that current available aircraft and satellite technology allow for advanced leak detection and quantification. For example, GHGSat's aircraft instruments and constellation of satellites are able to identify a super emitter emissions event at the facility level. Other existing satellites offer a higher detection threshold and lower spatial resolution, making it difficult to identify all the super emitter emissions events and to properly source allocate the emission.

Commenters (2345-GHGSat Inc., 2457-Providence Photonics, LLC) state when comparing the aircraft and satellite platforms, the difference lies in the potential frequency of observations. Aircraft platforms can provide a fine spatial resolution and lower detection threshold, but survey frequency is dependent on the scheduled aircraft campaigns. Satellites provide the advantage of frequent surveys. The commenter's (2345-GHGSat Inc.) satellites are currently the only ones capable of detecting emissions at the proposed 100 kg/hr emission rate threshold. The current constellation of six satellites (one demonstrator and five commercial satellites) provides the opportunity to observe the same area every two to three days. In April 2023, three additional satellites will be launched (GHGSat Inc, 2022), effectively increasing the opportunity to observe a given area every one to two days. Furthermore, Commenter (2345-GHGSat Inc.) will be launching another three satellites by the end of the fourth quarter 2023, effectively increasing the commercial satellite constellation to ten, one demonstrator, and one commercial satellite with a

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<sup>102</sup> This comment (or any other comment provided to improve other provisions that we contend are not appropriate to promulgate at all) does not concede that such a program is authorized under the statute. Rather, it is intended to ameliorate the problems associated with such a program in practice. TXOGA maintains that the Super emitter Program should not be issued based on the current proposal.

carbon dioxide sensor (GHGSat Inc., 2023). This satellite constellation will provide the opportunity to monitor methane emissions of a given area on a daily basis. For this, the commenter would like to propose the following tiered approach:

| <b>Remote Sensing Technologies</b> |                            |                           |                            |                            |                    |
|------------------------------------|----------------------------|---------------------------|----------------------------|----------------------------|--------------------|
| <b>Tier</b>                        | <b>Temporal Resolution</b> | <b>Spatial Resolution</b> | <b>Detection Threshold</b> | <b>Source Localization</b> | <b>Sensitivity</b> |
| Analytics                          | Weekly                     | 1000                      | 1000s                      | No                         | Low                |
| Public Satellites                  | Varies                     | Varies                    | >1000                      | Varies                     | Low-Medium         |
| GHGSat Satellites                  | 2-3 days (5 satellites)    | 25                        | >100                       | Yes                        | Medium             |
|                                    | 1-2 days (8 satellites)    |                           |                            |                            |                    |
|                                    | Daily (10 satellites)      |                           |                            |                            |                    |
| Aircraft                           | Bimonthly                  | <1                        | >10                        | Yes                        | High               |
| OGI                                | Annual                     | At source                 | >1                         | Yes                        | High               |

In addition, current public satellite systems used in the detection of methane from space are only capable of detecting ultra-emitter emissions. The commenter in turn, is currently the only satellite system capable of identifying emissions as small as 100 kg/hr, effectively identifying super emitters.

Response II-14-71: EPA acknowledges the commenters' input.

Comment: Commenter (2393-OSEE) states in the preamble to the SNPR (at 87 Fed. Reg. 74721), EPA requested feedback on the geographic elements of an evaluation<sup>103</sup> of equivalency between a program adopted by a state under either a CAA 111(d) plan, EPA's current SNPR, or the November 2021 Proposal. A nation-wide satellite monitoring program operated by EPA and states under a cooperative federalism framework would certainly simplify that evaluation, because an EPA/state run program covering the entire greater methane reductions (focusing on super emitters) than what would have occurred had EPA adopted either the November 2021 Proposal or the SNPR.

Response II-14-72: EPA acknowledges the commenters' input.

Comment: Commenter (2446-IPAA) states EPA should not simply deem these three detection methodologies sufficient/adequate/warranted without input from the general public and/or stakeholders. EPA should provide their basis and justification for these methodologies for the general public to evaluate, instead of simply picking three methodologies and asking the general

<sup>103</sup> The "IRA equivalence determination" referenced in the preamble.

public/stakeholders for the criteria – the "burden of proof" should be on EPA to demonstrate these methodologies are appropriate, not the other way around.

Response II-14-73: EPA acknowledges the comment and in the final rule, EPA is not pre-supposing certain technologies can meet the measurement criteria in the Super-Emitter Program and instead EPA is requiring any remote sensing technology be approved by the EPA for use under this program under the same criteria as the Advanced Methane Detection Technology Program.

Comment: Commenter (2453-Carbon Mapper and RMI) argue EPA should require third-party reporters to use remote methods (not requiring onsite access) to geolocate the origin of methane super emitter plumes to within 100 meters with 90% circular error probability. Precise geolocation can help reduce the likelihood of misidentifying facilities and can aid follow-up analysis by operators.

Response II-14-74: EPA agrees with the commenters' input and the final rule has been revised to include geolocation requirements to ensure that super-emitter data is being provided to the correct owner or operator.

Comment: Commenter (2457-Providence Photonics, LLC) states the specifications for these methods are very general and vague. The commenter did not find any performance based or instrument-based specifications in the proposed regulations to ensure that the method used to identify a super emitter is indeed capable of doing so, including quantifying the emission rate against the proposed threshold of 100 kg/hr as super emitter. The commenter did not find procedures in the proposal to be used to vet the technologies for this purpose. The lack of specificity for qualified methods to identify and quantify an emission as a super emitter will be problematic in implementing and administering the super emitter program. EPA should strengthen this area.

Commenter (2457-Providence Photonics, LLC) states the critical element of the super emitter program is not just detecting what appears to be a super emitter but quantifying the emission rate and comparing it to the super emitter threshold. The current QOGI device QL320 in the market is being upgraded to enable the measurement of emission rates in the range of super emitters. Figure 1 below shows controlled releases of methane at high release rates from an unlit flare and emission rates measured by the QL320. More details of this controlled release test can be found in Exhibit 1.<sup>104</sup>

Response II-14-75: EPA agrees the commenters input and the final rule has been revised to require technology used under the Super-Emitter Program to meet the same level of scrutiny as the Advanced Methane Detection Technology Program.

Comment: Commenter (2457-Providence Photonics, LLC) continues, section §5371b(c) and (d) specify operator's responses after receiving a super emitter notification. What if the operator

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<sup>104</sup> Figure 1. Emission rates of a super emitter: controlled vs. measured by QL320.

wants to dispute the super emitter event? What will be the procedures to resolve the dispute? What method(s) can be used to confirm that the release was at a sufficiently high rate to qualify as a super emitter? What if the event cannot be replicated upon receipt of the notification? The commenter believes these aspects should be addressed in the final rule.

Response II-14-76: EPA acknowledges the commenters' input. The final rule includes provisions which allows for an owner or operator to challenge a notification as having a demonstrable error, however the burden of proof of the error is on the owner or operator.

Comment: Regarding space sustainability, Commenter (2346-Encino Environmental Services, LLC) notes that their orbit consists of over 30,000 pieces of space debris that are potential safety and environmental concerns. EPA's proposal prompts and encourages an increased surge of satellite launches due to the proposed space monitoring provisions for the oil and gas industry. These provisions add to the already crowded orbital space. While the commenter support satellite monitoring, they also encourage the EPA to pursue effective satellite safety provisions, recycling incentives, debris prevention requirements, and satellite registration notification as technology develops and allows.

Response II-14-77: The Super-Emitter Program is not specific to satellite monitoring and EPA does not have authority regarding the deployment of this technology.

#### 14.4.3.3 Proposed Methane Detection Limit (MDL)

Comment: Commenters (2346-Encino Environmental Services, 2433-EDF et al., 2626-Kayrros) consider the proposed threshold of 100 kg per hour of methane to be appropriate.

Commenter (2433-EDF et al.) states EPA's proposed super emitter threshold of 100 kg/hr of methane of methane released aligns with the agency's stated bases for SERP as a backstop program. This threshold level helps ensure that the program would not capture permissible emission events and that SERP would not be duplicative of other standards or requirements in the rules, like the LDAR program. Rather, SERP would achieve emission reductions by assuring compliance with those rules. Moreover, the high emission threshold ensures that the program is administrable, as it will help avoid an influx of monitoring reports identifying smaller emission events that may be permissible. As the commenter and EPA have noted, there are permissible emission events at lower levels, like emissions from an uncontrolled tank, that would not necessarily be an impermissible emission event.<sup>105</sup>

Commenter (2626-Kayrros) agrees with EPA's decision to define a super emitter based on its flow rate, given the profusion of terms and definitions that vary greatly among stakeholders. The technical capabilities of the three main technologies (satellite, airborne and mobile) vary as well, and the proposed threshold of 100 kg per hour is a sensible compromise. Detection thresholds are highest for satellite monitoring, with systems based on Sentinel-2 (operated by the European Space Agency) being able detect methane sources down to 1 ton/hour. The detection threshold of

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<sup>105</sup> Id. at 74749; 2022 Joint Environmental Comments, *supra* note 1, at 63, 139.

the latest generation of satellites is measured in hundreds of kilograms per hour, and it is reasonable to expect the next generation of space sensors to reliably detect sources at 100 kg/hour.

Fig 1. Histogram of methane super emitters detected in selected oil & gas basins around the world using satellite imagery from Sentinel-2, detection threshold of Sentinel-2 and expected detection threshold of PRISMA.<sup>106</sup>

Additionally, commenter (2433-EDF et al.) states the use of a 100 kg/hr of methane threshold for this program is appropriate for the underlying legal justification and also based on a host of scientific, technical, and practical considerations. Most importantly, this threshold properly focuses resources on the largest and most harmful emission events, prioritizing their quick mitigation and repair. Emissions of this magnitude could release thousands of tons of methane in a matter of days or weeks. In the absence of SERP, these emissions might go undetected for up to six months or more (the length of time between semiannual LDAR inspections). A persistent event of this duration would release over 400,000 kilograms of methane, an amount having the same climate impact as 3,400 homes' annual energy usage.<sup>107</sup> In addition, such emission events should not be occurring at a properly designed and operated site, and therefore will likely indicate abnormal processes and equipment failures that are violations of the underlying regulatory requirements.

The commenter's (2433-EDF et al.) PermianMAP project, which consisted of numerous flyovers in the Permian Basin spanning multiple years, found a significant number of emission events exceeding 100 kg/hr from a wide range of operators. Many events of this magnitude resulted from unlit flares, failures on tank control systems, and gathering line malfunctions. Unlit flares and failed tank controls are both violations of the proposed standards for those affected facilities.<sup>108</sup> Other studies have frequently found that emission events above 100 kg/hr of methane make up a large fraction of total emissions even if they are generated by a small number of sites. For example, Zavala-Araiza et al. (2017) found that 20% of emissions were from sites with emission rates above 100 kg/hr. Researchers in the Permian have found 30-50% of emissions were due to sources with emission rates greater than 100 kg/hr.<sup>109</sup> And Cusworth et al. (2021) found that 44 out of 1000 sites observed had emission rates greater than 100 kg/hr, with some as high as 5,000 kg/hr.<sup>110</sup>

Commenter (2433-EDF et al.) states the scientifically backed 100 kg/hr threshold therefore appropriately captures the largest events likely to be violations of underlying standards while excluding many smaller permissible emissions, like certain vents and maintenance activities. The threshold also aligns well with the capabilities of currently available screening technologies, some of which require multiple passes before being able to quantify emissions. To address

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<sup>106</sup> Kayrros.

<sup>107</sup> EDF Methane Calculator, *supra* note 210.

<sup>108</sup> Additional information, including operator and geographic location, are available publicly on PermianMAP.org

<sup>109</sup> Stokes, et al., An aerial field trial of methane detection technologies at oil and gas production sites, Chem Rxiv (2022), <https://chemrxiv.org/engage/chemrxiv/article-details/625f27d2742e9f9470644f24>.

<sup>110</sup> See also Commenter (2433-EDF et al.) letter Section IV.C.1.

concerns about false detections of permissible maintenance events, EPA should require operators to report planned maintenance that could exceed 100 kg/hr and this information should be made publicly available. Commenter (2433-EDF et al.) also urge EPA to consider a secondary threshold of 1000 kg/hr that would entail heightened response action.

Response II-14-78: EPA acknowledges the commenters' input. EPA is maintaining the 100 kg/hr of methane threshold for a super-emitter detection however we realize this definition may be overly prescriptive in describing what technology could be used for this program, specifically limiting data from some satellite systems with higher detection thresholds as they would still provide actionable (*i.e.*, EPA verifiable) data. EPA has revised the language to remove any disincentives from using technology that is less sensitive than 100 kg/hr of methane.

Comment: Commenters (2306-Citizen's Climate Lobby, 2365-Climate Action California, 2410-California Office of the Attorney General et al.) request EPA lower the minimum threshold from 100 kg/hr.

Commenter (2410-California Office of the Attorney General et al.) suggests lowering the 100 kg/hr threshold for defining a super emitter emissions event in order to identify and mitigate a wide range of emissions events. The commenter suggests a threshold of 70 kg/hr to ensure that the super emitter threshold is within the range of what satellite monitoring can detect. While, as EPA notes, "no specific mass based or production-based rates have been formally or consistently applied to the term,"<sup>111</sup> several studies have defined super emitters with thresholds as low as 26 kg/hr.<sup>112</sup> One study applied a threshold of 26 kg/hr because it captured the highest-emitting one percent of sites, which accounted for nearly half of total site emissions in the production region.<sup>113</sup> A lower threshold would enable the SERP to reduce a larger quantity of methane and associated VOC emissions, while still ensuring that the program does not duplicate other requirements of the proposed rule.

Commenter (2410-California Office of the Attorney General et al.) argues lowering the threshold for a super emitter emissions event would not significantly increase costs to owners and operators and would in fact allow facilities to recover more natural gas for sale rather than emitting the gas into the atmosphere.

Commenter (2306-Citizen's Climate Lobby) notes that for notices about emissions below 100 kg/hour, the rule proposes that owners "are not required to take the actions." The rule should require owners to correct the emissions at least before a ton of methane escapes. Good facilities run well within the limits. Any exceedance which notifiers find should be corrected. This involves changing "rate of 100 kg/hr of methane or greater" to "rate higher than allowed by the

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<sup>111</sup> Id. at 74,749.

<sup>112</sup> Att. 32, Daniel Zavala-Araiza et al., Super emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions, 8 Nature Commc'ns. 14012 (2017), <https://doi.org/10.1038/ncomms14012>; Att. 33, Daniel H. Cusworth et al., Intermittency of Large Methane Emitters in the Permian Basin, 8 Env. Sci. & Tech. Letters 567 (2021), <https://doi.org/10.1021/acs.estlett.1c00173>.

<sup>113</sup> Zavala-Araiza et al., *supra* n.86.



Rule”, and in (c) “10 calendar days” to “10 hours or before a ton of methane escapes, whichever is longer”.

Commenter (2365-Climate Action California) notes other organizations have referred to emissions rates over 25kg/hr as super-emissions. The EPA should consider lowering the emissions rate that qualifies as a super emitter event after the SERP has been underway for a few years.

Response II-14-79: EPA acknowledges the commenters’ input; however, EPA has chosen to maintain the super-emitter threshold of 100 kg/hr of methane.

Comment: Commenters (2227-Western Energy Alliance, 2283-Endeavor Energy Resources, 2399-GPA Midstream Association, 2458-MiQ, 2483-INGAA) indicate the minimum threshold needs to be increased from the proposed 100 kg/hr. The event threshold is unjustified and inappropriately low.

Commenter (2458-MiQ) recommends that EPA only be directly and immediately involved in events that are extraordinary (i.e., ultra-emitter events of >1000 kg/hr). Involvement in other events may result in a slow-down of operator follow-up and repair. This would result in more methane being released – at odds with the intention underlying the SERP. EPA may, of course, follow-up based on reports review.

Commenter (2227-Western Energy Alliance) notes that a super-emitter event would represent one hour of 100 kilograms or 0.1 metric tonnes (mT) of methane emissions which is equivalent to 2.5 mT of CO<sub>2</sub>e emissions. For comparison the proposed Subpart W new source category of “other large release events” has a reportable event threshold of 250 mT of CO<sub>2</sub>e emissions, which would be the equivalent of just over 4 days of a continuous NSPS OOOOb super-emitter type event. In comparison to the Subpart W “other large release” threshold, the super-emitter threshold is excessively stricter, indicating the proposed NSPS OOOOb threshold is too low.

Commenter (2283-Endeavor Energy Resources) argues EPA does not fully explain how it reached these 100 kg/hr thresholds. Instead, the agency mostly emphasizes the need to set a threshold sufficiently high enough to avoid duplication of other monitoring programs and to focus resources on “the largest and most concerning emissions events.”<sup>114</sup> But that explanation does not support the selection of 100 kg/hr, as opposed to some other number. In fact, the closest to a justification is EPA’s observation that there are satellites purportedly capable of identifying emission events greater than 100 kg/hr at individual sites.<sup>115</sup> Thus, absent some other explanation, it appears that EPA selected its threshold based on simply the capabilities of existing detection technology, rather than public health or environmental considerations.<sup>116</sup>

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<sup>114</sup> Id. at 74,749.

<sup>115</sup> See Id.

<sup>116</sup> See also Id. (“EPA is soliciting comment on this list of technology types that could be applied for the identification of super emitter emissions events and the threshold of 1 00 kg/hr of methane.”).

Commenter (2283-Endeavor Energy Resources) provides EPA 's proposed super emitter threshold equates to 0.1 metric tons per hour ("mt/hr") of methane, or approximately 2.5 mt/hr of carbon dioxide equivalent ("CO<sub>2</sub>e") as a point of comparison.<sup>117</sup> EPA has recently proposed revisions to the GHGRP and has specifically proposed a category of "other large release events" to capture "abnormal" emissions events not otherwise accounted for in the existing regulations and has defined that category to encompass events emitting at least 250 metric tons of CO<sub>2</sub>e per event.<sup>118</sup> If EPA does retain this program in any final rule, it should consider aligning its definition of super emitter event in the Methane Proposal to better align with its proposed category of "other large release events."

Commenter (2399-GPA Midstream Association) recommends that if the agency pursues this approach, it should align the threshold for notification with the proposed revisions to EPA's GHGRP, 40 CFR Part 98, which has a proposed reporting threshold for "large emission events" of 250 tonnes methane carbon dioxide equivalents (or 10 tonnes of methane). Applying a 24-hours timeframe for such events, this would result in a threshold of approximately 415 kg/hour. Should EPA increase the Subpart W threshold, the commenter would recommend EPA aligning this program accordingly. Likewise, EPA should align with the phrasing of "large emission events" in subpart W, in lieu of "super emitter."

Commenter (2483-INGAA) states the threshold of 100 kg/hr for the SERP needs to be increased because normal, permitted operations (including blowdowns, which are done for safety purposes) will exceed that threshold. Any permitted emissions cannot be considered a "super emitter event." In addition, the duration of the associated measurement is undefined, and additional clarity is needed regarding measurement duration and documentation of long-term or persistent emissions.

Commenter (2483-INGAA) provides the example, EPA has collected data, by event type, under Subpart W of the GHGRP. One of the examples in those reported data is compressor blowdowns, which can occur when a unit is taken out of service due to a decrease in pipeline demand or to conduct maintenance. Data from the GHGRP for 2016 compiled by the PRCI showed an average compressor blowdown of approximately 500 kg per event. Scrubber blowdowns (another event type under the GHGRP) averaged 1,700 kg per event in 2016. While scrubber blowdowns are rare (occurring on average less than once a year<sup>119</sup>), they could result in the owner or operator receiving a notice under the SERP, even though those emissions result from normal operations and are not "super emitter" events.

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<sup>117</sup> This is calculated using EPA's Greenhouse Gas Equivalences Calculator, available at <https://tinurl.com/GHGEC>.

<sup>118</sup> See Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, 87 Fed. Reg. 36,920, 36,928, 37,083 (June 21, 2022). EPA similarly characterizes the Methane Proposal's super emitter events as "abnormal" emission events. See 87 Fed. Reg. at 74,747.

<sup>119</sup> PRCI, "Methane Emissions from Transmission and Storage Subpart W Sources," at 10 (Aug. 2019) (noting there were 296 scrubber/strainer blowdowns across 350 facilities in 2016), <https://www.prci.org/Research/CompressorPumpStation/CPSProjects/CPS-17-01A/142206/168614.aspx?source=generalSearch>.

Commenter (2483-INGAA) adds further support for the fact that the threshold for the SERP is too low can be seen by examining the “incident” reporting threshold in PHMSA regulations. Those regulations have a reporting threshold of 3,000,000 standard cubic feet (SCF) of natural gas.<sup>120</sup> For natural gas containing 92% methane, this equates to 57,600 kg/hr—magnitudes higher than the proposed 100 kg/hr threshold. In addition to the PHMSA regulations, state programs also show that the threshold of 100 kg/hr for the SERP is too low. For example, the programs in Louisiana and Maryland have thresholds of 1,000,000 SCF.<sup>121</sup> Additional examples include: a single one-hour event at the proposed threshold equates to emissions that are 0.01% of the applicability threshold for facility reporting under EPA’s GHGRP. EPA has referred to other events, such as the Aliso Canyon storage well event in Southern California, as examples of super emitter events but that event had cumulative emissions six orders of magnitude higher than the proposed threshold and hourly rates nearly three orders of magnitude higher than the proposed threshold.

Response II-14-80: EPA acknowledges the commenters’ input, we acknowledge that some super-emitter events will be larger than 100 kg/hr however limiting investigation to only higher-level emissions, negates the potential emission reductions from emission events using the threshold of 100 kg/hr of methane in the NSPS.

Comment: Commenter (2315-DEC) does believe that EPA has partially addressed the super emitter issue in wells by removing the minimum emissions threshold by which they must comply. While the additional language that was proposed may not require all wells to detect for leaks at the emission rate that the New York State regulation does, the commenter supports this portion of the proposal.

Response II-14-81: EPA acknowledges the commenters’ support.

Comment: Commenter (2346-Encino Environmental Services, LLC) states weather, wind, sun positioning, radiative transfer, and other factors must be considered to properly quantify event detection. Periodic calibration events should be utilized to ensure that above ground systems are realized according to manufacturer recommendations. In addition, the commenter believes EPA should adopt stricter rules and regulations surrounding above ground monitoring capabilities.

Commenter (2346-Encino Environmental Services, LLC) argues a measured average MDL should be adopted for various operations. Measured average MDLs are recommended due to potential plume dispersion and contamination from neighboring sites (transient emissions). Ground-based emissions verification tools can be used to corroborate aerial findings and aerial site-specific action levels. Additionally, surveys should be done in a manner that ensures that CMS systems are fully functional and stable prior to use of visual detection systems. Moreover, there should be a testing protocol for above ground systems that ensure not only the MDL of

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<sup>120</sup> 49 CFR § 191.3(1)(iii) (definition of Incident).

<sup>121</sup> Louisiana Admin. Code tit. 33, pt. 3, § 309; Code of Maryland Regulations 26.11.41.

each system, but also ensures data reliability from detection, monitoring, stability, clarity, and network reliability.

Commenter (2346-Encino Environmental Services, LLC) continues, there should be an MDL and chemical composition established for all above ground monitoring systems. With currently available systems, many times there can be false positives for different chemical combinations that would result in some companies, locations, or entities being classified as super emitters and/or other action levels (thresholds, i.e., air-quality permit limits) when they do not actually produce methane outputs (spectral interferences – water vapor (H<sub>2</sub>O), carbon dioxide (CO<sub>2</sub>), ammonia (NH<sub>3</sub>), etc.). There should also be a requirement for multiple device verification for all MDL operations and testing procedures.

Response II-14-82: EPA acknowledges the commenters' input, the final rule includes the requirement that technology be approved for use in the Super-Emitter Program, as part of that program a technology provider would need to address any potential interferences in their measurement approach and develop "method" identifying DQOs and DQIs to ensure the measurement is performed correctly and any interferences are minimal. Regarding the sensitivity requirements, technology used for the Super Emitter Program would define their detection threshold based on probability of detection, in the same manner as the Advanced Methane Detection Technology Program.

While this comment is specific to a technology provider, EPA also recognizes many candidates third parties use public or semi-public data streams from multiple satellites deployed through National or International Space Agencies. EPA does not intend to conduct a review of the base technology being used for these types of efforts and will instead need to evaluate how the candidate third-party takes data from these satellites to ensure detection and location.

Comment: Commenter (2366-BHE) gives the example, several sectors have completed over a decade of annual measurements of key sources of potential leaks, such as leakage from unit isolation valves through compressor vents, reciprocating rod packing leakage, and centrifugal compressor wet seal degassing vent emissions. That data, and other available peer reviewed data, should be analyzed to assess potential emission rate thresholds and the implications (i.e., cost and benefit) of choosing one threshold over alternatives.

Response II-14-83: EPA acknowledges the commenters' input.

Comment: Commenters (2346-Encino Environmental Services, LLC, 2626-Kayros) adds space-based, or even aerial monitoring can be misleading if not calibrated properly.

Response II-14-84: EPA acknowledges the commenters' input.

#### 14.4.3.4 Permitted Operations/ Short intermittent events

Comment: Commenters (2220-WDEQ, 2248-NDPC, 2254-Permian Basin Petroleum Association (PBPA), 2351-Jonah Energy LLC, 2366-BHE, 2393-OSEE, 2399-GPA Midstream

Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API, 2446-IPAA) argue the proposed threshold of 100 kg/hr of methane is problematic. EPA has not properly considered the types of standard events that occur within natural gas operations, or the time element associated with “event-based” emissions (such as venting emissions during normal operation and maintenance) versus continuous or persistent emissions.

Commenters (2220-WDEQ, 2248-NDPC, 2254-PBPA, 2294-Ohio Oil and Gas Association, 2351-Jonah Energy LLC, 2366-BHE, 2391-CEC, 2393-OSEE, 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API, 2429-Wyoming Outdoor Council, 2446-IPAA) are concerned that certain permitted events, such as scheduled blowdowns or maintenance and safety measures could erroneously appear as “super emitter” events as defined by this program. EPA’s super emitter program should identify the sampling timeframes and protocols to ensure the emission event is ongoing and/or persistent. In these instances, operators would have to undertake unnecessary root-cause analyses in spite of the fact that the events reported are not compliance issues, nor are they repeatable for operators.

Response II-14-85: EPA acknowledges that the Super-Emitter Program could identify maintenance events with this program and has structured the investigation and reporting of these allowable events in the final rule to account for these events.

Comment: Commenters (2254-PBPA, 2305-The Williams Companies, Inc., 2366-BHE, 2446-IPAA) add EPA has not justified this threshold versus alternative emission levels. For example, the initial proposal discussed example events that triggered the need for a super emitter element within these regulations, but the examples provided were long duration events with emissions orders of magnitude higher than a shorter-term event emitting at 100 kg/hr. EPA should assess the implications of the threshold versus alternatives. Commenter (2254-PBPA) argues it would be more defensible for EPA to align the threshold with the GHG Reporting Program, which defines “other large release” as a release of at least 250 mtCO<sub>2</sub>e per event.

Response II-14-86: EPA acknowledges the comment; however, the EPA is maintaining the 100 kg/hr of methane in the NSPS final rule. The proposed definition for large release in the GHGRP is not intended to be aligned with the NSPS as the reporting structure in the two rules have different goals. Likewise, the proposed revisions to the GHGRP recognizes the NSPS super-emitter program event may not already be accounted under the source categories in subpart W, which is why they proposed to require facilities to consider notifications of potential super-emitter emissions event under the super-emitter provisions of NSPS OOOOb at 40 CFR 60.5371b and calculate associated events when they exceed our proposed thresholds (88 FR 50290).

Comment: Commenters (2248-NDPC, 2393-OSEE) state the preamble for the SNPR states that “Given the intermittency of super-emitter emissions events, the failure of the operator to find the source of the super-emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier.” 87 Fed. Reg. 74750. This statement implies that the company or facility in question is guilty until proven innocent. Given the possibility of errors, this is highly problematic, and EPA should show discretion in accepting

information provided by 3rd parties as proof that a super-emitter exists. Plausible reasons why no super-emission event happened such as accuracy of the location, actual concentration of the super-emitter, and human error in interpretation could be reasons why such an allegation of a super-emitter at a facility may be incorrect, and it should not be assumed that the company just did not find the methane release. EPA taking a stance of guilty until proven innocent should not be the default for the super-emitter program.

Response II-14-87: EPA has revised the final rule to improve the reliability of the technology used in this program and has added additional responsibility of the third-party notifiers to ensure improved quality of the data being provided to a potential owner or operator. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

Comment: Commenter (2366-BHE) states typical operational releases may exceed the proposed threshold in some cases. For example, EPA has collected data on compressor station blowdowns, by event type, under Subpart W. An example from that reported data is compressor blowdowns, which can occur when a unit is taken out of service due to a decrease in pipeline demand or to conduct maintenance. Subpart W data for 2016 compiled by PRCI in a report<sup>122</sup> provided to EPA showed an average compressor blowdown of approximately 500 kg per event. Another event type, scrubber blowdowns averaged 1,700 kg per event in 2016. However, this event occurred, on average less than once per year (i.e., 296 total scrubber/strainer blowdowns occurred across 350 facilities in 2016). Clearly, these operational emissions, with data already available to EPA through the GHGRP and reported on-line annually for public access, do not constitute “super emitter” events.

Commenters (2248-NDPC, 2366-BHE, 2399-GPA Midstream Association) state singular observations of emissions from remote sensing technologies may constitute an observation of a planned or authorized activity that is part of normal facility operations, such as a blowdown or other authorized short-term events (an engine startup) or short-term malfunctions (a stuck dump valve) that vent gas at a high rate, but for a short period. Third-party observations may estimate these emissions as exceeding the threshold, but the actual estimated emissions may be well below the threshold. Accordingly, EPA should provide that, operators/companies notified of an observation, should not be subject to reporting and corrective action if the event was a) associated with normal operations or maintenance activities and/or b) the observed emissions event is determined by the operator to not exceed the applicability threshold. To implement this, the commenters recommend that for an emissions observation to be deemed as a persistent emission event for which a notice may be submitted, the observation must have been made between two distinct time intervals (such as 3 hours apart).

Commenter (2366-BHE) provides an example, a third-party could measure an emission rate of 1.7 kg/min for a few minutes and assume the source exceeds 100 kg/hr (i.e., 1.7 kg/min x 60 min

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<sup>122</sup> Pipeline Research Council International (PRCI) Report, “Methane Emissions from Transmission and Storage Subpart W Sources,” Report No. PR-312-16202-R03, August 2019.

= 102 kg/hr). In reality, this source could be a single, short-term blowdown event (e.g., compressor blowdown) lasting several minutes with total emissions far less than 100 kg and not at all indicative of a “super emitter” event or source. It is imperative that this program include proof that the emission source is persistent (e.g., an ongoing large leak) and a time element and/or cumulative emission total should be defined for categorizing an emission source as a super emitter.

In Commenter’s (2429-Wyoming Outdoor Council) decades of air quality work and experience in Wyoming, uncontrolled blowdowns have been a significant source of unregulated emissions, especially in the UGRB. For example, during a two-month period in the winter of 2020, one major operator in the basin reported 1,008 blowdown events totaling more than 159 hours of uncontrolled emissions venting. With dozens of other operators in this same region, we’d estimate that blowdowns result in hundreds of thousands of dollars in wasted gas annually and thousands of tons of vented methane and VOCs in this region alone.<sup>123</sup>

Response II-14-88: EPA acknowledges the commenters concerns that blowdowns will identify as super-emitter events if these emission events are in excess of 100 kg/hr of methane. The program is structured in such a manner that when an owner or operator receive a notification of an event and when that a maintenance event was the cause of the emission, they would report it as such. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. EPA recognizes that permitted emission events, like blow-down events, are currently reported to the public through other non-governmental programs, without context.

Comment: Commenters (2258-MSC, 2305-The Williams Companies, Inc.) request that EPA clarify the source of the 100 kg/hr emission rate used in the definition of “super emitter events.” The commenters’ (2258-MSC, 2305-The Williams Companies, Inc.) understanding is that not all remote sensing technologies that are proposed and not all vendors providing these technologies are able to meet that sensor resolution. Additionally, the commenters (2258-MSC, 2305-The Williams Companies, Inc.) maintain that the threshold does not include a minimum monitoring period to characterize an event as a “super emitter.” As a result, a brief event lasting seconds or minutes could be categorized as a “super emitter” event during a flyover using remote sensing technology. This could result in high numbers of events requiring a rapid response and use of operational resources when the total emissions from the event do not meet this threshold over a one-hour period. At a minimum, there should be a duration component determined by at least two observations more than 24 hours apart with detected emissions above the permitted threshold.

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<sup>123</sup> More than meets the eye: How unseen emissions continue to impair air quality in Wyoming upper Green River Basin. April 2021. <https://wyomingoutdoorcouncil.org/2021/04/29/how-unseen-emissions-continue-to-impair-air-quality-in-wyomings-upper-green-river-basin/>.

Commenters request EPA consider revising the definition of a super emitter emissions event to be a quantified emission rate that is persistent for more than 24 hours and that averages greater than 100 kg/hr over that time period. The EPA is proposing to define a super emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater. However, no duration is proposed. A temporal component is necessary to differentiate a super emitter emissions event from a short-term normal operations event.

Commenter (2391-CEC) recommends EPA establish a minimum monitoring period for the proposed super emitter event threshold of 100 kg/hr. Without this, a brief event lasting mere seconds or minutes could be categorized as a “super emitter event” during a flyover using remote sensing technology. That could result in high numbers of events requiring a rapid response and needless expenditure of an operator’s resources when the total emissions from the event do not meet the threshold over a one-hour period. Commenter (2391-CEC) recommends that EPA specify that a super emitter event does not occur unless the 100 kg/hr emission rate is observed at least two times over a period of no less than 24 hours.

Commenter (2446-IPAA) asks will one "fly-by" measurement extrapolated out to an hour be sufficient to trigger EPA's requirements on owners/operators? If EPA is using an hourly based emissions rate, and it would seem unlikely that a shorter time would be sensible, then data taken to identify the super emitter incident is both of that duration and persistence. For example, measurements must be longer than one hour such as either multiple hours over a single day or hourly over more than one day. Past history of data collection using the methods EPA has identified for this program have generated not just hourly emissions, but annual emissions based on data taken for ten minutes or less. This type of short duration data collection must not be allowed. The burden of proof that the source is emitting at a rate of 100kg/hour needs to be on the third-party notifier – a snapshot in time is not sufficient. EPA should establish criteria for the third-party to demonstrate that there is some reasonable likelihood that there is potential event at the facility such that excessive rates of methane are occurring for an extended period of time. Examples of requirements that EPA could require include, but are not limited to, continuous actual measurement for a period of time or repeated snap-shot measurements, periodically, over a period of period, e.g., three measurements separated by 12-hour intervals.<sup>124</sup>

Commenter (2248-NDPC) requests the criteria for Super Emitting events be expanded to require more than one data point separated by a reasonable period of time, (i.e., at least a day).

Response II-14-89: EPA acknowledges the commenters’ input. EPA disagrees with the commenter that super emitter events must be proven as persistent. EPA recognizes that these events are infrequent and may be intermittent, however the intent of this additional monitoring effort is to identify this emission when they happen so the cause can be investigated.

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<sup>124</sup> The cost of multiple flights/verification should not be a consideration as EPA does not consider the costs of flights associated with advanced methane detection technologies.



Comment: Commenter (2433-EDF et al.) also recognizes potential concerns about intermittency, wherein the detected emissions may not be present when the operator responds and visits the site. While emission events of this magnitude could be intermittent, they will generally indicate an underlying operational or design flaw at the site and should therefore be immediately investigated. Further, many may be persistent major malfunctions like unlit flares that should be immediately addressed. Commenter (2433-EDF et al.) also notes that the LDAR standards do not require multiple detections before follow-up and adding this requirement in SERP would also be inappropriate. Because events exceeding 100 kg/hr are extremely harmful, a single detection and quantification is sufficient to trigger a response and multiple observations should not be required. Many available technologies already require multiple passes before quantification is possible as well. If there are repeat detections at the same site, the operator should face heightened response requirements.

Response II-14-90: EPA acknowledges the commenters' support.

#### 14.4.3.5 Source Allocation

Comment: Commenter (2345-GHGSat Inc.) understands that source allocation is a critical aspect of the super emitter emissions response program. Satellites that have a coarse spatial resolution have challenges to correctly allocate the emission source. Satellites with finer spatial resolution (e.g., like GHGSat's) have the ability to zeroing on a facility, however, ownership registered in different databases may or may not be up to date. A database aggregator like Enverus proves to be a good source of ownership information. This is a subscription-based system. The premise of the platform is that it provides a myriad of information associated with the entire energy value chain. Despite this, not all the frequent changes get updated immediately. Other sources are associated with the different environmental permitting dependencies in each State. Even though these data are free, scouring the different databases can be daunting.

Response II-14-91: EPA acknowledges the commenters' input.

Comment: Commenter (2258-MSD) states the proposed regulation does not account for the fact that using remote sensing to detect methane emissions accurately often takes five to seven detections during multiple flyovers.<sup>125</sup> Weather conditions, wind speed, distance from the source and other factors can produce variability in results. Geolocation errors are also common, creating the potential for mis-identifying sources or even which facility the emissions are coming from.

Commenter (2258-MSD) is concerned that the prescribed methods may overstate the emission rate due to variability in leak localization. The prescribed testing methods have varying ability for leak localization from 1 to 10 meters for fixed monitors, 1 to 50 meters for flyovers and 25

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<sup>125</sup> To better understand the variables regarding remote sensing, the MSD encourages the U.S. EPA to review "Monitoring methane emission from oil and gas operations" – Collins, Orbach et al; Optics Express: <https://opg.optica.org/oe/fulltext.cfm?uri=oe-30-14-24326&id=477126>.

meters to 7 kilometers for satellite monitoring. Variability in leak localization can be due to distance, weather, and site conditions.

Response II-14-92: EPA acknowledges the commenters' input, EPA has recognized spatial resolution as a concern, and the final rule EPA has included criteria for identifying emission sources by third-party notifiers and has taken spatial resolution into account when conducting follow-up investigations.

Comment: Commenter (2258-MSC) notes that identified emissions can include background emissions and emissions from other sources. The combined emissions will result in overstating emissions and potentially triggering the super emitter programs investigation, publication and reporting requirements.

Response II-14-93: The final rule places the responsibility on the third party to identify the accuracy of the geolocation of the emission event and the mass emission threshold has been met. We also recognize that background emission could overstate emissions, however the super-emitter threshold is so high any overstatement of emissions should be minimal unless the background source also is or nearly a super-emitter.

Comment: Commenter (2354-Business Roundtable) states in major oil and gas producing areas, it is not uncommon for hundreds of individual sources to exist within a relatively small geographic area. In these areas, these hundreds of individual sources may be owned or operated by dozens of different companies. Accurately identifying a specific source of emissions and/or the owner or operator responsible for the equipment in these dense producing areas likely will be challenging with the remote observation technology in use today. While good data exists as to the location of individual oil and gas well sites, easily accessible and precise public data does not exist for processing facilities, tank batteries and other oil and gas field infrastructure subject to regulation under this proposed rule. As a result, a super emitter event triggering a required response can be misdirected to the incorrect owner or operator. This will waste resources that could better be used in ensuring compliance with the new regulations.

Response II-14-94: EPA acknowledges the commenters' input. EPA agrees that identifying sources can be difficult, as mentioned, however it is possible based on the technology chosen by a third party and the procedures followed by the third-party to confirm attribution. With EPA is a centralized role to evaluate technology and the expanded criteria for third parties to meet to be certified, owner or operators should have more confidence in the notification data they receive as part of this notification. Furthermore, owner or operators do have the opportunity to challenge a notification if they believe there is demonstrable error.

#### ***14.4.4 Root Cause Analysis***

Comment: Commenters (2627-BCI, 2296-NMED, 2345-GHGSat Inc., 2433-EDF et al.) support the requirement for owners or operators to conduct a root cause analysis upon notification of a super-emitter event and make the corresponding corrective action.

Commenter (2345-GHGSat Inc.) provides a table recommending Root Cause Analysis be required for various classification of emitter events.

| Emission rate (kg/hr) | Classification  | OGI follow-up (days) | Repair-First attempt (days) | Repair-Final attempt (days after first attempt) | Delay of Repair | Root Cause Analysis? |
|-----------------------|-----------------|----------------------|-----------------------------|-------------------------------------------------|-----------------|----------------------|
| Below 10              | Process-emitter | 14                   | 30                          | 35                                              | Yes             | No                   |
| ≥10 to <100           | Major-emitter   | 14                   | 15                          | 30                                              | No              | Yes                  |
| ≥100 to <1000         | Super-emitter   | 7                    | 10                          | 25                                              | No              | Yes                  |
| ≥1000                 | Ultra-emitter   | 5                    | 5                           | 20                                              | No              | Yes                  |

Commenter (2433-EDF et al.) argues EPA’s proposed response measures for operators, which include a root cause analysis and corrective action, are appropriate due to the common causes of super emitter events and the need to quickly mitigate such events to drive down emissions. Super emitter events of this magnitude will often be caused by unlit flares and tank malfunctions. In these situations, operators should be able to fix the underlying issue quickly, but may have to implement equipment, design, or operational changes to prevent recurrence. In situations where the emissions result from a permissible emissions event, maintenance activity, or are not from an affected source, operators should be able to easily make that determination based on their own records and could submit that information in response. There may also be situations in which the emissions are intermittent and no longer present when the operator surveys they site. In this instance, a certification from the operator that emissions were not present should satisfy their response obligation. However, if there are repeat detections at the same site or a detection of very large emissions (over 1000kg/hr), there should be heightened response requirements.

Response II-14-95: EPA acknowledges the commenters’ input, we see the utility of a heightened response for higher level detections, however, to avoid additional complexity to the program, we are maintaining the super emitter threshold of 100 kg/hr of methane in the final rule.

Comment: Commenters (2177-Ute Indian Tribe, 2282-Kinder Morgan Inc., 2305-The Williams Companies, Inc., 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API, 2458-MiQ, 2483-INGAA) state that requirements for a ‘root cause analyses should be revised due the wide definitions of this term across different groups.

Commenters (2177-Ute Indian Tribe, 2282-Kinder Morgan Inc.) recommend replacing "root cause analysis" with "investigation". The details of that investigation should be left to the operator. Therefore, if EPA moves forward with the SERP, EPA should rename the “root cause analysis” to better convey the contemplated tasks. Commenter (2282-Kinder Morgan Inc.) also suggests “Immediate cause inspection” as an appropriate term that would better reflect the apparent intent behind the existing proposed regulatory text.

Commenters (2326-AXPC, 2428-API, 2483-INGAA) suggest that “root cause analysis” be replaced by “investigative analysis.” The commenters do not object to doing an analysis to

determine whether an emissions event has occurred and to take steps to ensure that it will not happen again. But using the phrase “root cause analysis” has connotations that lead to a much more involved process than EPA appears to envision in the Supplemental Proposed Rule.

Commenters (2326-AXPC, 2428-API) support investigating the source and cause(s) of significant emissions events that are brought to an operator’s attention Through the process described in our comments. The commenter agrees that EPA’s investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA’s use of the term “root cause analysis” is problematic and ambiguous. The concept of “root cause analysis” is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented.

Commenter (2305-The Williams Companies, Inc.) also recommends the removal of all references to “root cause analysis” within the Supplemental Proposed Rule. The term triggers a specific type of investigatory activity within the oil and gas industry that is significantly different than what is described in the proposed regulatory text. The actions described as a “root cause analysis” in proposed § 60.5371b(c) are investigatory techniques rather than components of a root cause analysis. The American Society for Quality defines root cause analysis as “a collective term that describes a wide range of approaches, tools, and techniques used to uncover causes of problems. Some root cause analysis A approaches are geared more toward identifying true root causes than others, some are more general problem-solving techniques, and others simply offer support for the core activity of root cause analysis.”<sup>126</sup> Under this definition, the root cause analysis is a much more detailed process, and typically involves the participation of numerous individuals and resulting man hours to conduct the analysis and development of recommended corrective actions. That does not appear to be what EPA proposed in the SERP and the EPA should make the appropriate changes to the proposed rule.

Commenter (2399-GPA Midstream Association) recommends that EPA strike references to a “root cause analysis” throughout the Supplemental Proposed Rule and regulatory text as a notice recipient is not actually required to conduct one. It is only required to conduct various inspections and to document various issues listed in proposed §§ 60.5371b(c)(1)-(10). This is not a “root cause analysis” in that it is not a formal systematic investigation, using multiple potential methodologies, into the potential causes of an incident that identifies corrective actions to reduce the probability of similar future incidents.<sup>127,128</sup> Root cause analyses take significant amounts of time – far longer than the 10 days required by the Supplemental Proposed Rule. Therefore, EPA

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<sup>126</sup> Cause Analysis Tools, American Society for Quality, <https://asq.org/quality-resources/root-causeanalysis/tools>.

<sup>127</sup> See, e.g., OSHA-EPA, Fact Sheet, The Importance of Root Cause Analysis During Incident Investigation (Oct. 2016). Available at, <https://www.osha.gov/sites/default/files/publications/OSHA3895.pdf>.

<sup>128</sup> Dep’t of Energy, Root Cause Analysis Guidance Document, DOE NE-STD-1004-92 (Feb. 1992). Available at, <https://www.standards.doe.gov/standards-documents/1000/1004-std-1992/@@images/file>.

should remove all references to “root cause analysis” and replace them with a more generic and appropriate term, such as “investigation” or “evaluation.”

Commenter (2403-The Petroleum Alliance of Oklahoma) requests EPA use different terminology such as a technical investigation rather than root-cause analysis. Operators should not be required to conduct a detailed root-cause engineering analysis of an event (*e.g.*, an open tank hatch) when a site visit can easily identify the problem and remedy the situation.

Commenter (2458-MiQ) recommends that EPA substitute the term ‘root cause analyses with the term ‘causal examination’. The term root cause analysis is ambiguous and can mean different things to different actors, as well as having different usages in different professional sectors. Commenter (2458-MiQ) recommends that this burdened term be substituted with the more clear ‘causal examination.’ While this is clearer and subject to less ambiguity than ‘root cause analysis’ one can surmise that a search for causation might also result in infinite regress. As such, the commenter recommends that EPA provides a clear definition of what is intended by the term for this section. A definition for ‘causal examination’ might be an analysis of sources and processes involved or potentially involved in a leak that results in a statement of determination about cause and effect that has a high or a reasonable level of associated confidence.

Response II-14-96: EPA acknowledges the commenters’ input and have revised the final rule to replace the root cause analysis with the term “investigation” to avoid any confusion. We have also defined what this “investigation” should consist of to avoid any misinterpretation.

Comment: Commenter (2483-INGAA) recommends the following text changes to §60.5371b(c), (d) of the proposed rule:

(c) Addressing super-emitter emissions events. c conducted within 14 business days, the owner or operator must notify EPA and let the Agency know when the investigative analysis and initial corrective action will be completed, which shall not exceed 90 days.

Response II-14-97: EPA acknowledges the commenter’s input and as part of the change to a primarily a compliance assurance program, EPA has made revisions for how an owner or operator must respond to a super-emitter notification.

The program now only includes a timeline for completing and reporting the super-emitter investigation. The timeline for repairs, if any are required, is dependent on the cause of the super-emitter event.

Comment: Commenter (2282-Kinder Morgan Inc.) states this approach is consistent with other regulatory regimes that also provide a very short timeframe to conduct an immediate cause inspection. For example, a Pipeline and Hazardous Materials Safety Administration (“PHMSA”) regulation provides an apt example of the customary types of analyses that would be performed on a five-day timeframe. 49 CFR § 191.25, on filing safety-related condition reports, requires a report to be filed “in writing within five working days.” Importantly, the information to be included in such reports under § 191.25(c) does not require a “root cause” analysis and is purely

descriptive. In contrast, EPA's Emergency Planning and Community Right to Know Act (EPCRA) regulation provides a longer time period for a more in-depth analysis. Specifically, 40 CFR § 355.40(b) requires a follow-up notice "as soon as practicable" that details, in relevant part, actions taken to respond to and contain a release.<sup>129</sup>

Commenter (2282-Kinder Morgan Inc.) goes further, if EPA intends for the analysis to be a more in-depth root cause evaluation (rather than identifying immediate causes), then the timeframe should be extended to at least 30 days for the complete analysis and corrective action, consistent with the EPCRA example discussed above.

Response II-14-98: As explained above in Response II-14-90 and -91, EPA has removed the requirement for root cause analysis and have revised the owner or operator responses accordingly.

Comment: Commenter (2305-The Williams Companies, Inc.) recommends the SERP also include an avenue by which an owner or operator can quickly respond to a notification without an investigation if the operator can identify the 'emissions event' as a result of a planned, operational emissions event, such as a blowdown. Though this factual information is a component of the "root cause analysis" outlined by the EPA, these events are contemplated and accounted for in a facility's air permit. The implication that the 100 kg/hr of methane threshold triggers an investigation regardless of the circumstances is an arbitrary notion without any reasonable justification.

Response II-14-99: As explained above in Response II-14-90 and -91, EPA has removed the requirement for root cause analysis and have revised the owner or operator responses accordingly. Included in these responses is the identification of any maintenance events which were occurring at the time of the super-emitter event.

Comment: Commenter (2298-Pioneer Natural Resources USA, Inc.) contends no investigative analysis should be required if the emissions are not associated with/emitting from an affected facility under NSPS OOOOb.

Response II-14-100: EPA appreciates the commenters concerns however we disagree that the Super Emitter Program should be limited to NSPS OOOOb. EPA has revised the rule to remove the NSPS OOOOb affected facility definition and is finalizing the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. EPA co-proposed the program as a compliance assurance program in the December 2022 supplemental proposal. EPA has detailed the statutory authority of the program in Section X.C.1 and XI.C.1 of the preamble of the final rule.

Comment: (2410-California Office of the Attorney General et al.) supports EPA's suggested timelines for operator response to a super emitter emissions event notification. Given the scale of

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<sup>129</sup> EPA has interpreted "as soon as practicable" to mean 30 days. 75 Fed. Reg. 39,852, 39,857 (July 13, 2010).

super emitter emissions events, it is imperative that they be addressed and mitigated promptly. EPA's proposal would require owners and operators to initiate a root cause analysis within five calendar days after receiving a third-party notification, and to complete corrective actions within 10 days of notification. Commenter (2410-California Office of the Attorney General et al.) supports these timelines and provide several suggestions to clarify the actions required by owners and operators, to ensure emissions events are promptly mitigated and promote transparency.

Commenter (2410-California Office of the Attorney General et al.) notes under the procedures an owner or operator must undertake after receiving a notification of a super emitter emissions event, the first time that that EPA would receive any update from the owner or operator would be 25 days after receipt of the notification, when the owner or operator submits its written report after completion of the corrective action, or 30 days after receipt of the notification, if the owner or operator determines that the corrective action would take more than 10 days to complete.<sup>130</sup> This means that EPA—and the public—would be in the dark for nearly one month after a super emitter emissions event is discovered.

Commenter (2410-California Office of the Attorney General et al.) suggests that, as an intermediate step, the owners and operators be required to submit a report within 10 calendar days of receiving the notification. This 10-day report could include the following information: (1) whether the reported emissions event is traceable to a source located on the owner or operator's site; (2) whether the emissions event is ongoing, and if not, when it stopped; (3) whether the root cause analysis has been completed, and if so, the results of the analysis; and (4) whether the corrective actions are complete, and if not, justification for why additional time is needed. Additionally, as discussed above, if the owner or operator believes the notification contains demonstrable error, they could submit a report demonstrating the error in lieu of the 10-day report. EPA should also specify that a root cause analysis and corrective action(s) are required even if an owner or operator determines that the emissions event is not ongoing, unless the owner or operator can demonstrate that a super emitter emissions event did not occur.

Commenter (2410-California Office of the Attorney General et al.) notes under EPA's proposal, the first action that an owner or operator is required to take after receiving a third-party notification is to confirm that the reported emissions event is traceable to a source located on their site and investigate to confirm if a super emitter emissions event is still ongoing.<sup>131</sup> EPA does not propose a time frame for this first step. Commenter (2410-California Office of the Attorney General et al.) suggests that owners and operators should be required to complete this first step within five calendar days after receiving the notification. This initial step is essential, as it will confirm whether the emissions are in fact attributable to the owner or operator, and whether the emissions event is ongoing. This timeline would align with the requirement that the owner or operator initiate the root cause analysis within five calendar days.

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<sup>130</sup> Id. EPA proposes that owners and operators would complete corrective actions within 10 days after receiving a notification and submit a written report 15 days after completing the corrective action.

<sup>131</sup> Id.

Commenter (2410-California Office of the Attorney General et al.) states EPA proposes that owners and operators be required to complete corrective actions within 10 calendar days of receiving a notification.<sup>132</sup> However, EPA also proposes an alternative option when corrective actions will take more than 10 days to complete, whereby an owner or operator can develop and submit a corrective action plan 30 days after receiving a notification, describing the corrective actions completed as of that date, additional measures proposed to reduce or eliminate emissions, and a schedule for completion of those measures.<sup>133</sup> Commenter (2410-California Office of the Attorney General et al.) is concerned that this exemption would swallow the rule and suggest that EPA clarify that owners and operators are expected to complete corrective actions within 10 calendar days of the notification and must provide justification if the corrective actions are not complete in that time frame. The commenter suggests that this justification take the form of a 10-day status report.

Response II-14-101: EPA acknowledges the commenters' input. EPA has made changes to the final rule to account for the changes in the legal authority of the rule. One of these changes is the timing required to conduct the investigation into a super-emitter event. We agree that owner or operators should act as soon as possible to a notification, but we do not find 10 days to be practical for a national rule, instead we are allowing for 15 days. We believe 15 days requirements a reasonable timeframe within which to conduct and report the required investigations, due to the overall scope of the industry and that many of the affected owner or operators operate over multiple basins. We expect as the program matures, many owners or operators will be able to respond in effectively in less time, however due to the novelty of this program, more time is required.

Comment: Commenter (2483-INGAA) recommends the following text changes to §60.5388c(c), (d) of the proposed rule:

(d) Corrective action plans for additional analysis. If, upon completion of the ~~root cause~~ investigative analysis and initial corrective actions such as those described in paragraph (c) of this section, you are notified of a super-emitter emissions event from the same emission source which was determined under paragraph (c) not to be an allowed venting of emissions as part of normal operations, including routine maintenance, or if the initial corrective actions will require more than ~~40~~ 14 business days to complete, you must develop a corrective action plan that describes the initial corrective action(s) completed to date, additional measures that you propose to employ to reduce or eliminate the super-emitter emissions event, and a schedule for completion of these additional measures. You must submit the correction action plan to the Administrator according to the schedule in paragraphs (d)(1) and (2) of this section.

(1) If you are submitting a corrective action plan because you were notified of a super-emitter event from an emissions source which you had previously completed actions in paragraph (c) of this section, you must submit the corrective action plan within ~~30~~ 90 days after receipt of the notification.

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<sup>132</sup> Id.

<sup>133</sup> Id.



(2) If you are submitting the corrective action plan because you were unable to complete the actions in paragraph (c) in ~~10~~ 14 days, you must notify the EPA submit the corrective action plan within ~~30~~ 90 days of the notification in paragraph (b) of this section.

Response II-14-102: EPA acknowledges the commenters input. We have revised the final rule to remove the corrective action plan requirement, instead with the program as primarily a compliance assurance programs, the timeline for repairs, if any, is dependent on where the emissions are coming from, for example, if the emission event was from equipment subject to the fugitive component emission standard in NSPS OOOOb, you would be subject to the same repair and reporting requirements of that applicable standard.

The only additional reporting requirement is when the super-emitter event is ongoing at the time of reporting, and then you would be required to update the EPA when the event has been repaired.

Comment: Commenters (2306-Citizen's Climate Lobby, 2365-Climate Action California, 2433-EDF et al., 2444-NAACP) contend a condensed timeline is more appropriate to perform a root cause analysis and corresponding corrective action than proposed.

Commenter (2306-Citizen's Climate Lobby) notes P.25 - 40 CFR 60.5371b(d) For issues which need extra time, the rule should require a corrective action plan within 3 days, not 30 days.

Additionally, commenter (2306-Citizen's Climate Lobby) notes on P.23 - 40 CFR 60.5371b(c) When the owner is notified of emissions over 100 kg/hour (2.4 tons/day), the rule should require the owner to start finding the cause within 1 hour, not 5 days, and correct it within 10 hours, not 10 days. For every hour of emissions, the atmosphere is harmed, and neighboring communities are at risk of explosion. Owners who cannot mobilize that fast are not competent to own such dangerous facilities and need to have competent emergency help on call or be fined. If the equipment had a visible fire or chlorine leak, EPA would certainly expect owners to start addressing it in an hour, and have resources prepositioned to do so, and generally expect to solve it within 10 hours. Methane emissions are explosive. Owners can send staff (called pumpers) to close the well and maintenance technicians to fix leaks.

Commenter (2365-Climate Action California) recommends that a root cause analysis and corrective actions begin within 48 hours of notification and completion of corrective actions occur within 7 calendar days. An emission rate of 100kg/hr is large enough to be a priority that should be addressed immediately. Also, because there is a time lag between when a super emitter event is detected remotely and when the analysis needed to locate it is completed, waiting five more days after notification as proposed seems imprudent.

Commenter (2433-EDF et al.) supports EPAs proposed 5-day initiation and 10-day completion timeframe, and urge EPA to consider a shorter initial response requirement given the seriousness of emissions exceeding 100 kg/hr. When equipment, design, or operational changes would be required to prevent recurrence based on the root cause analysis, the commenter believes EPA's proposal to require submission of a written report with a corrective action plan and information

about completion of that plan within 30 days provides appropriate flexibility to operators in addressing more complex issues. The plan should include information about site design, deviations from applicable underlying standards, potential causes of the emission events, and the steps necessary to prevent recurrence. This information should be publicly available and should be sent to state regulators as well so that nearby communities have multiple channels for access.

Commenter (2444-NAACP) argues the timeline is too long between the notification of a high level of pollution within a community and responsive action. As it stands, communities can be poisoned with greenhouse gas pollution under the super emitter program for up to five days prior to any root cause analysis and up to ten days for any corrective action to take place.<sup>134</sup> Under the proposed rule, an owner has discretion once notified of emissions over 100 kg/hour (2.4 tons/day) as to whether they want to act immediately or wait several days to take corrective actions.

Commenter (2444-NAACP) states for every hour of emissions, the atmosphere is harmed, and neighboring communities are at risk of an explosion. As outlined in the NAACP report, air in many Black communities already violates various air quality standards and at least 6.7 million Black people live near oil refineries. Allowing an extensive time period to respond to these crises implicates racial justice issues and runs counter to the promise of environmental justice promised by the Biden Administration. Communities should not have to suffer due to the lack of emergency planning by owners and operators. The regulations must outline the need for owners to have competent emergency help or face accountability actions by the EPA. Additionally, if the equipment had a visible fire or chlorine leak, the EPA should expect owners to start addressing it within an hour, and have resources prepositioned to do so. Resolution of the crisis must take place, generally, within ten hours.

Commenter (2444-NAACP) continues, there are several other places where the proposed rule allows for additional time to act or no action, when communities face continued exposure to high levels of these emissions for an extended period:

- For issues that need extra time, the rule should require a corrective action plan within three days, not 30 days.<sup>135</sup>
- For notices about emissions below 100 kg/hour of methane, the rule proposes that owners “are not required to take the actions.”<sup>136</sup> At a minimum, the rule should require owners to correct emissions before a ton of methane escapes. Good facilities run well within the limits. Any excess found should be corrected. This involves changing “rate of 100 kg/hr of methane or greater” to “rate higher than allowed by the Rule”, and in (c) “10 calendar days” to “10 hours or before a ton of methane escapes, whichever is longer”.

Response II-14-103: EPA acknowledges the commenters’ input. With the rule being finalized as primarily a compliance assurance rule, we have chosen not to finalize the root cause analysis and

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<sup>134</sup> Proposed Rule P.23 - 40 CFR 60.5371b(c).

<sup>135</sup> Proposed Rule, P.25 - 40 CFR 60.5371b(d).

<sup>136</sup> Proposed Rule, P.20 - 40 CFR 60.5371b.

corrective action approach and have finalized that owner or operators conduct and prescribed investigation as detailed in Section X.C.2 and XI.C.4 of the preamble of the final rule.

Comment: Commenters (2202-TXOGA, 2284-Kairos Aerospace, 2305-The Williams Companies, Inc., 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2483-INGAA) request EPA extend the proposed timeline to perform root cause analysis.

Response II-14-104: EPA acknowledges the commenters' input. In the final rule EPA has revised the "root cause analysis" as an "investigation" and EPA has defined what that "investigation" consists of as detailed in Section X.C.2 and XI.C.4 of the preamble of the final rule. EPA has remained consistent with the proposed timeline and an owner operator has 15 days to determine if the emission event is ongoing and if not, bring the site into compliance and conduct any repairs necessary.

Comment: Commenter (2202-TXOGA) believes that expeditious deadlines should apply for such notifications to facilitate identification of emissions issues and also to ensure that third-party notifiers do not delay in providing information. This is particularly important given that deadlines for response will apply to the operator and that EPA should be conducting a review of the notices prior to requiring sources to respond. With the near-term deadlines for responding to notices, companies should not be put in the position of dealing with multiple notices that are sent to them in batches, which will prevent, or at least significantly impair the ability to make, timely response deficient. Commenter contends that is not the intent of the program. Any third-party who wishes to participate needs to be sufficiently resourced to meet the basic requirements to make the program function smoothly.

Response II-14-105: EPA agrees with the commenter that third-party notifier must provide the data as soon as possible to make this program effective. Therefore, a certified third-party notifier must submit super-emitter data within 15 calendar days of the observed emission event to the EPA. EPA will review that data, and if found to be reasonable and accurate, will provide the notification to the owner or operators. Data provided after 15 days are not considered to be actionable.

Comment: Commenter (2202-TXOGA) states the proposed five calendar days to initiate and 10 calendar days to complete a root cause analysis and initial corrective actions is too short, given that operators cannot predict when and where third-party surveys will be undertaken, that sites are often at remote locations, and that personnel availability is limited on non-business days. For all of these reasons, the deadlines should be adjusted to provide more time and to be based on business days, not calendar days.

Commenter (2284-Kairos Aerospace) agrees with EPA's assessment that large sources of emissions are worthy of prompt action, but believes the timeline established in the Proposed Rules is excessively tight and creates unnecessary complexity from a management perspective.

Response II-14-106: EPA acknowledges the commenters input. EPA has remained consistent with the proposed timeline and an owner operator has 15 days to determine if the emission event is ongoing and if not, bring the site into compliance and conduct any repairs necessary. Due to the size of these emission events, EPA considers it critical to act as soon as possible to limit these emission events.

EPA has also defined the “investigation” to allow both off-site and on-site evaluations of these super-emitter events in order to make them more targeted and to decrease potential burden.

Comment: Commenter (2284-Kairos Aerospace) notes that EPA’s current proposal for the SERP requires root cause analysis and repair initiation within five days and completed repairs within 10 days of notification of a super emitter, and a written report within 15 days of completing the root cause analysis. EPA’s proposal also requires ground follow-up on advanced leak screening surveys with no specific timeline but would require initiating a root cause analysis within 24 hours of the follow-up ground survey, completion of a root cause analysis within 5 days, and repair within 30 days. It also requires repairs resulting from OGI leak surveys to occur within 15 days of survey. Further, it requires leaks identified by AVO to have first repair attempts made within five days, and final repairs completed within 15 days.

Commenter (2284-Kairos Aerospace) recommends that timelines are streamlined so that the SERP requires 15 calendar days to follow up on reported detections and make non-SERP timelines align.

While the commenter (2284-Kairos Aerospace) appreciates the concern that these large emissions need to be stopped quickly, they state that EPA can easily model the impacts of aligning things on similar timelines. The reality is that a few days do not have major impacts on total emissions, except in the most extreme cases. Aligning repair timelines for the SERP and advanced leak screening surveys will streamline compliance and reduce complexity with minimal cumulative emissions impact.

Response II-14-107: The Super Emitter Program is independent of any existing monitoring program of a site and is only designed for large emission events, and therefore the required timelines are considered reasonable for that program. The key difference for of an owner or operator conducted monitoring program, is they are aware when those surveys occur and triggering a response to a failed emission control can be plan for, however with the super-emitter program, and owner or operator will not know when these surveys have occurred, making planning for a response more difficult.

Comment: Commenter (2284-Kairos Aerospace) contends that this web of timelines will likely create confusion, and it’s not clear that from an emissions mitigation perspective it could be considered strictly necessary. According to the commenter (2284-Kairos Aerospace), FEAST modeling can be used to measure the impacts of repairs within 5, 15, or 30 days. Based on the commenter’s (2284-Kairos Aerospace) experience with modeling tools, they anticipate the changes in emissions based on those different timelines would be negligible.

Response II-14-108: The super emitter program is being finalized as primarily a compliance assurance program and does not include a required timeline for repair of emission events, instead when owner or operators identify these emission events, they are required to conduct repairs of that equipment consistent with the requirements in the applicable subpart.

Comment: Commenter (2305-The Williams Companies, Inc.) contends that the timeline for an owner or operator to respond to a notification of a super emitter emissions event is inadequate and places an impractical and unrealistic burden on owners and operators. As currently proposed, owners and operators are required to initiate a Root Cause Analysis to determine the cause of emissions event within 5 days of receiving a third-party notification, and any resulting corrective action must be completed within 10 calendar days after receiving the third-party notification, along with providing a notification to the EPA within 15 days of completing the corrective actions. While the rule offers a 30-day extension if the corrective action plan cannot be completed within 10 days, the whole timeline offered to investigate, complete and report the emissions event from the super emitter notification is inadequate when taking into account the amount of time to review, investigate and verify that the reported emissions event is accurate and is based on approved methodologies and not a false “positive.” Further, the timeline does not account for scenarios where the recipient of the notification is part of a joint venture where certain steps must be taken pursuant to the contractual agreements between the parties prior to any investigation or corrective action.

If the Super emitter program is implemented as part of this rulemaking, commenter (2305-The Williams Companies, Inc.) states that the owner or operator will need at least 30 days to conduct the RCA and take initial corrective actions as required. If the corrective actions cannot be completed within 30 days of the initial notification, then the owner or operator should be able to request a reasonable extension, which could be more than 30-days, and it be readily granted upon showing good cause.

Response II-14-109: EPA acknowledges the commenters’ input, In the final rule EPA has redefined root cause analysis as an “investigation” and EPA has defined what that “investigation” consists of. EPA has remained consistent with the proposed timeline and an owner operator has 15 days to determine if the emission event is ongoing and if necessary, bring the site into compliance and conduct any repairs necessary.

The final rule does not include a requirement for corrective action and instead requires and affective owner or operators to take action to conduct repairs of fugitive equipment and/or bring in equipment into compliance with applicable requirements in the rule (e.g., covers and closed vent systems).

Comment: Commenter (2399-GPA Midstream Association) notes proposed § 60.5371b(c) requires the recipient of a notice to initiate a “root cause analysis” within five days of receiving the notice and complete both the “root cause analysis” and an initial corrective action within 10

calendar days of receiving the notice.<sup>137</sup> References to “calendar days” should be changed to “business days.” Unlike large petroleum refineries or chemical plants, which have employees working 24 hours a day, seven days a week, most midstream sites are unmanned. Engineering staff at the company’s headquarters or a regional office would conduct the investigation. These are salaried employees, not shift workers, that typically work Monday through Friday (excepting federal and state holidays where offices are closed) during normal business hours. Further, investigation time may be consumed by time needed to travel to and from the sites, some of which are relatively remote. Therefore, EPA should afford owners and operators 10 business days (or two weeks) to complete their investigations.

Commenter (2403-The Petroleum Alliance of Oklahoma) notes EPA is proposing that operators initiate a root cause analysis and take corrective actions within 5 calendar days of an owner or operator receiving the notification of the super emitter emissions event, and completion of corrective actions within 10 days of the notification. EPA is proposing operators submit a written report within 15 days of completing the root cause and corrective action to EPA and/or the delegated state delegated agency’s authority. These time frames are inadequate as some locations are remote in nature or in some instance, may require longer time frames to obtain equipment or schedule service companies to complete the corrective action.

Action Requested: EPA and/or the state delegated agency should be the entity to notify the operator of an event. Operators would then begin a technical analysis (not a root cause analysis) and take corrective actions, if possible, within 5 calendar days. EPA should allow final repairs and report to EPA and/or state delegated agency within 30 calendar days. If corrective actions take longer than 30 days, operators could submit a corrective action plan to the EPA and/or the state delegated agency. This would align with other types of emission event reports required by state delegated agencies.<sup>138</sup>

Commenter (2483-INGAA) encourages EPA to allow 14 days to conduct an analysis of the incident (which is sufficient for a simple event, but not for a more complex one), and if the analysis cannot be conducted in that period of time to let the Agency know when the analysis will be available, not to exceed 90 days.

Furthermore, commenter (2483-INGAA) is concerned that 10 days does not provide owners or operators with enough time to analyze a potential super emitter event. Commenter suggests instead that EPA provide owners or operators with 14 business days to conduct an analysis of the incident and provide EPA with recommended actions to avoid future occurrences. This should work for simple incidents. In some cases, however, more time will be needed. If the analysis cannot be conducted within 14 business days, the owner or operator should notify EPA and let the Agency know when the analysis will be available, which in no event may exceed 90 days.

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<sup>137</sup> As discussed below, the Supplemental Proposed Rule requires an investigation or response, not a root cause analysis.

<sup>138</sup> Ibid.

Proposed Regulatory Text for Proposed §§ 60.5371b, 60.5388c:

[The regulatory text proposals in Comment: 422-4137 and Comment: 422-4145 were originally part of this comment.]

Response II-14-110: EPA acknowledges the commenters' input, In the final rule EPA has redefined root cause analysis as an "investigation" and EPA has defined what that "investigation" consists of. EPA has remained consistent with the proposed timeline and an owner operator has 15 days to determine if the emission event is ongoing and if not, bring the site into compliance and conduct any repairs necessary.

With the rule being finalized as primarily a compliance assurance rule, the final rule does not include any timelines for when the repairs need to be made, as those requirements are already included in the applicable subpart.

#### **14.4.5 Costs**

Comment: Commenters (1686-GHGSat Inc., 2288-NDDEQ) note the proposed rule also states that owners and operators do not bear the cost of monitoring and detecting super emitter emissions events. Clarity is needed as to who will in fact bear the costs of the work.

Response II-14-111: EPA recognizes the commenters thoughts, EPA does not consider the costs for conducting the surveys as the program is designed for third-parties, independent of the agency.

Comment: Commenters (2288-NDDEQ, 2345-GHGSat Inc., 2433-EDF, 2626-Kayrros) do not expect there to be a significant cost associated with the super emitter program EPA is proposing. Commenters (2288-NDDEQ, 2345-GHGSat Inc.) agree that, in practice, there should be no additional cost associated with the work practice of identifying and repairing an emission detected under the super emitter program. The commenters understand that operators must perform compliance assurance measures in between periodic screenings, the SERP is practically behaving as one compliance assurance, which, according to the proposed rule, operators will not bear the cost of monitoring and detecting super emitter emissions events.

Response II-14-112: EPA recognizes the commenters support for the Super Emitter Program.

Comment: Commenters (2288-NDDEQ, 2345-GHGSat Inc.) state if the expense of monitoring and detecting super emitter events will not be borne by the operators, the most logical solution would be for the EPA itself to be responsible for covering the costs of the services from third-party notifiers. The EPA should consider procuring all the methane data obtained by remote sensing aircraft, mobile monitoring platforms, and satellites to identify super emitter emissions events, and then making that data available transparently to all operators as a public good, thereby accelerating mitigation while mitigating the risk and reducing compliance costs for all oil and gas stakeholders.

Response II-14-113: EPA acknowledges the commenters input; EPA does not intend to play a direct role in funding or conducting third-party monitoring. This program is designed to rely solely on third-party monitoring and data review by independent entities.

Comment: Commenter (2433-EDF et al.) states there should be little to no cost associated with the program. Owners and operators should already be addressing malfunctions and poor operating conditions as part of their normal operations, so the costs of SERP would already be accounted for in a facility's operational costs and the costs of complying with the underlying standards. A super emitter event would indicate likely noncompliance with standards for the underlying source—including a source-specific limit or work practice—so operators would already be required to come back into compliance with the source-specific standard. In any event, if there are additional costs associated with investigating and addressing super emitter events, those costs would be minor and highly justified in relation to the benefits gained by stopping these huge emission events, making any associated costs “obviously cost-effective.”<sup>139</sup>

Commenter (2626-Kayros) states they do not have proprietary insights on the costs of mitigating super emitters. That said, studies from reputable institutions including the Climate & Clean Air Coalition and the International Energy Agency show that the cost of mitigating methane emissions is modest. Furthermore, it is widely assumed that addressing large sources is more cost-effective (in \$ per ton of methane abated) than addressing a much larger number of small sources. On that basis, the EPA is right to assume that the costs imposed on operators by the proposed SERP are modest.

Response II-14-114: EPA acknowledges the commenters' support.

Comment: Commenters (2220-WDEQ, 2254-PBPA, 2279-U.S. Small Business Administration, 2292-West Virginia Attorney General et al., 2326-AXPC, 2333-LongPath Technologies, Inc., 2393-OSEE, 2399-GPA Midstream Association, 2446-IPAA) consider the proposed super-emitter program to incur substantial costs, particularly to small businesses.

Commenter (2279-U.S. Small Business Administration) notes small businesses have raised significant concerns about the proposed SERP. These operators want to ensure that the program's emphasis is on the response to these third-party reports, sent in good faith and to which they can respond in good faith, not on enforcement for methane emissions that are otherwise permitted. Further, these small oil and gas producers are concerned that third-party reporters could be motivated to impose bureaucratic costs unrelated to emissions or to their permit requirements to permanently reduce fossil fuel extraction in this country.

Response II-14-115: EPA acknowledges the commenters' input. EPA has revised the super-emitter program to have EPA in a central role to vet third party notifiers and to provide an independent review of the prior to providing notifications to an owner or operator.

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<sup>139</sup> 87 Fed. Reg. at 74752–55.



EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. EPA sees this as a potential cost saving to those small businesses by providing timely emission data to them so these excess emissions can be captured and sold.

Comment: Commenter (2220-WDEQ) strongly disagrees with EPA's assertion in the preamble that "the proposed SERP would provide a cost-effective backstop to the rest of the regulatory program" (74748). This program will consume state-level resources in WDEQ's Compliance and Monitoring programs, as state agencies will nevertheless have to spend additional time responding to and investigating root cause analyses, corrective actions, and monitored data. Ultimately, this process will unnecessarily burden the commenter's already-effective programs with no additional financial support from EPA.

Response II-14-116: EPA recognizes the comment. EPA has revised the super-emitter program to have EPA in a central role to vet third party notifiers and to provide an independent review of the prior to providing notifications to an owner or operator. EPA has taken on this burden to alleviate any potential burden on state agencies. Furthermore, the burden for investigation and reporting is on the owner or operators and their reporting requirements for the super emitter rule are for the most part, the imbedded in the fugitive emission monitoring and compliance monitoring program.

The only additional requirement for reporting is through the super-emitter program when an emission event is ongoing at the conclusion of the investigation period.

Comment: Commenter (2254-PBPA) argues responding to such reports (even when inaccurate) requires significant time and compliance reviews. The proposed program creates opportunities for operational disruptions that are unnecessary given the extensive monitoring requirements that will be a part of any final rule. These burdens will be especially acute on small businesses. EPA should revise its economic assessment to reflect the costs of responding to such reporting, including the cost on small businesses.

Response II-14-117: EPA does not consider the cost of an investigation to be overly burdensome and is designed to rely on potentially existing information to do perform the bulk of the investigations. EPA does not require the owner or operator of an oil or natural gas facility to conduct extensive monitoring requirements and emission events of 100 kg/hr of methane or more should be relatively easy to detect. EPA has included an estimated of burden of owner or operators subject to this program in the Supporting Statement for NSPS OOOOb available from the public docket.<sup>140</sup>

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<sup>140</sup> SUPPORTING STATEMENT. Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After December 6, 2022. (40 CFR part 60, subpart OOOOb).

Comment: Commenter (2292-West Virginia Attorney General et al.) argues third-party monitoring of super emitter events could lead to substantial new costs. Increased compliance costs are the most obvious, as increased investigations produce more response actions. 87 Fed. Reg. at 74,752. Those costs increase if the super emitter events lead to enforcement action or litigation. Companies will also have to grapple with new public relations costs, as super-emitting notices will be posted on a public website. Id. at 74,750. And third parties, who are newly deputized to police oil and gas facilities, may be encouraged to trespass on private property to monitor and measure for super-emitting events, leading to more potential harms and damages. Cf. Stuart N. Riddick, et al., Measuring Methane Emissions from Abandoned and Active Oil and Gas Wells in West Virginia, 651 SCI. OF THE TOTAL ENV'T 1849, 1865 (2019) (noting how private authors faced a “significant problem” in “land access” when they tried to measure methane emissions in West Virginia because “much land [is] private, used for hunting and posted against trespass”).

Response II-14-118: EPA acknowledges the commenters’ input. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. The program requires the use of remote sensing technology and strictly forbids the collection of methane emission data from accessing a site. If a certified third party has been found to illegal access a well site (i.e., trespassing) it would be grounds to have their certification revoked.

Comment: Commenter (2326-AXPC) notes EPA has erroneously concluded that “there should be no additional cost associated with this work practice standard for the super emitter emissions event affected facility.” EPA suggests this because EPA expects that “as part of normal operations, owners and operators should already be correcting equipment malfunctions and/or poor operations as such issues arise; therefore, costs associated with maintaining normal operations should already be accounted for in their operational costs.”<sup>141</sup> Such logic is entirely circular and inconsistent with EPA’s own stated concerns and findings regarding EPA’s claimed super emitter emissions events. If normal operational practices would catch and resolve all super emitters, then EPA would not have a justification that a super emitter program is necessary to finding super emitters. Thus, EPA clearly intends the program to require additional action beyond what is being taken and identified today.

Response II-14-119: EPA has chosen not to finalize the rule under the OOOOb affected facility rationale, has instead finalized under the rule as the co-proposed compliance assurance program, and the requirement for additional action is consistent does not go beyond the requirements in the rule, beyond follow-up inspection.

Comment: Commenter (2326-AXPC) estimates operators would expend at a minimum 20-30 hours of personnel time to respond to and investigate each super emitter notification, including time spent chasing intermittent events, identifying known maintenance events, communicating with the notifier, conducting a root cause analysis (investigative analysis as proposed by the

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<sup>141</sup> Id. at 74,752.

commenter), responding to public inquiries for notifications posted online, and potentially pursuit of third-party notifier disqualification for false notifications. The costs associated with these efforts will depend on whether an operator utilizes internal or external personnel and other operator-specific considerations – e.g., travel distance. However, under no circumstances can EPA simply assume that there will be no costs.

Response II-14-120: With EPA in a centralized role with this program, approving the methane detection technology, certifying the third parties, and reviewing data before notifying an owner or operator, we disagree an operator would need 20 – 30 hours to investigate and notification. Furthermore, EPA has revised the requirement for conducting an investigation for the owner or operator to first include off-site analysis using maintenance logs, monitoring data (if applicable), and SCADA data to evaluate whether an emission event is ongoing and then an on-site analysis to confirm the presence or absence of a super-emitter event. These are in place to provide an effective review without being onerous.

Comment: Commenters (2284-Kairos Aerospace, 2333-LongPath Technologies, Inc.) state the EPA is correct that there would be no added cost of the program for those sites using periodic screening or OGI. However, for sites using continuous monitoring, the super emitter events will already have been logged and repaired as a result of detection by the continuous monitoring technology. Therefore, operators will need to respond to these events, which had already been repaired by the time the notification from the super emitter event program had been received, two times. This results in an added cost to the operator. Further, these operators will be listed publicly as having super emitter event detections, even if they had already resolved the issue within a rapid time frame. Therefore, operators of sites with continuous monitoring installed should be given the opportunity to opt-out of some portion of the program, for example the public reporting portion, or be given an opportunity for streamlined response reporting.

Response II-14-121: EPA acknowledges the commenters input. EPA disagrees that sites that use continuous monitors should be exempt from the reporting requirements in the rule, however, to address the usefulness of continuous, which should be able identify these large emission events as they happen, we have included an investigation step to use data from these systems to determine the presence or absence of a super-emitter event.

Comment: Commenter (2393-OSEE) responds to EPA’s request for comments regarding the assumption that “that there should be no additional cost associated with this work practice standard for the super emitter emissions event affected facility.” 87 Fed. Reg. 74752. This seems unlikely as in almost every case an OGI camera with a properly trained OGI operator would be needed to find the potential super emitter. For many companies this would require a third-party contractor who would be making an additional visit to the site, outside of the normally scheduled semi-annual or quarterly OGI monitoring program. Therefore, this super emitter work practice would not be able to be done with no additional cost, as EPA seems to believe. If additional monitoring must be conducted, especially in more remote locations like those found in the western part of Oklahoma and the Oklahoma Panhandle, the monitoring, travel, root cause analysis, and coordination between operations and environmental staff would be in addition to

the regular monitoring program. EPA should re-assess this idea that it would be no-cost to companies to find and fix these super emitter events.

Response II-14-122: EPA thanks the commenter for their input. EPA has revised the final rule to define what the follow-up should consist of and no longer includes criteria for a corrective action/repairs, instead the rule relies on existing criteria for the equipment affected under the super-emitter program.

Comment: Commenter (2399-GPA Midstream Association) notes even with such a highly developed imaging platform, third parties will have significant difficulty pinpointing exactly which source is the alleged “super emitter,” and most third-parties must do with far less sophisticated equipment and software. As framed, nothing would constrain one private party from merely sending notices to multiple sources knowing that, at most, only one of the recipients is potentially responsible. On the contrary, EPA proposes to protect third parties who are sending the notices in such a situation: “the failure of the operator to find the source of the super emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier.” 87 Fed. Reg. at 74,750. Yet, each recipient would have to investigate their facility or facilities in response to the notice. This will mean diverting personnel, or having to hire new personnel or contractors, to investigate potential violations or malfunctions, often at remote unmanned locations (and some of which are difficult to access during the winter months), without any hard evidence those facilities are the source except the assertion of another private party. Despite EPA’s conclusion that the SERP is “obviously cost-effective,” 87 Fed. Reg. at 74,752, the Supplemental Proposed Rule seems to give the actual costs and burdens that would be involved minimal consideration. In fact, if a company receives multiple notices per week, regardless of whether those notices are accurate or not, the time and resources required to respond would be immense. If EPA proceeds with this approach in some fashion, it should review fully and carefully the full range of costs associated with this type of program.

Commenter (2399-GPA Midstream Association) notes the Supplemental Proposed Rule mistakenly claims that “[t]o the extent there are additional costs associated with the investigation or mitigation of these [Super emitter] events, the EPA expects that the costs would be minor in relation to the benefits of stopping such huge emissions event, making them obviously cost-effective.” 87 Fed. Reg. at 74,754.

Commenter (2399-GPA Midstream Association) states EPA offers no data, study, or other hard analysis to support this conclusory assertion. For that reason alone, EPA should reconsider its approach. Regardless, EPA apparently assumes that every source receiving a “Super emitter” compliance order will, in fact, be the cause of an alleged super emitter event and can cost-effectively resolve the alleged emissions. However, while there have been improvements in satellite and airborne imaging, few can provide an accurate designation of a “Super emitter” source.

Response II-14-123: EPA thanks the commenter for their input. EPA has revised the final rule to include a requirement that remote sensing technology used in this program are approved for use

Super Emitter Program. The criteria that these technologies must meet are explained in sections X.B, X.C, XI.B, and XI.C. of the preamble to the final rule, and these criteria include a spatial resolution requirement which must be met.

Comment: Commenter (2446-IPAA) considers EPA's leniency with regard to third-party notifiers submitting inaccurate information to skew EPA's "cost-effectiveness"/BSER analysis. First off, requiring a third-party submitting inaccurate information three times at the same source/location before a third-party notifier loses its certification is unacceptable. "Three-strikes and you're out" is not appropriate when you are dealing with existing sources, often operated by small business. Who is going to compensate the owner/operator for the costs associated with conducting a root cause analysis (a concept not defined or described by EPA in its proposal), when it is determined that the third-party notifier made a mistake? EPA fails to account for the costs associated with the SERP when the third-party gets the data wrong. To suggest that a third-party notifier can submit an owner/operator to the expenses associated with the SERP three times, with no ramifications to the third-party notifier is simply unfair. Commenter (2446-IPAA) suggests that third-party notifiers post a bond sufficient to cover the cost associated with an owner/operator responding to the SERP. If the third-party's data is inaccurate, the bond is released to the owner/operator and the third-party notifier is required to post twice the bond amount which would be released to the next owner/operator if/when the next time the third-party notifier wrongly accuses an owner operator of a super emitter event. If EPA is insistent on requiring "three strikes", then the bond should be tripled after the second erroneous submittal. The third-party notifiers need to have skin in the game and owner/operators need to be compensated for erroneous submittals.

Response II-14-124: EPA acknowledges the commenters' input. Burdensome, erroneous reporting will be avoided by through the certification of the third-party certification requirements in the rule and the requirement they use remote sensing technology that have been approved for use in the Super Emitter Program.

Comment: Commenters (2227-Western Energy Alliance, 2254-PBPA, 2283-Endeavor Energy Resources) request further analysis of the cost-effectiveness of the proposed Super emitter Program.

Commenter (2254-PBPA) believes EPA has underestimated the costs of its SERP without adequately quantifying the benefits.<sup>142</sup> While EPA claims that it "will make all of the critical policy decisions and fully oversee the program,"<sup>143</sup> it is disclaiming "a greater role for the

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<sup>142</sup> 87 Fed. Reg. at 74,754. Moreover, even if there are costs associated with the investigation and mitigation, the threshold for identifying a super emitter emissions event is so high that it ensures that the emissions reductions achieved by the mitigation are cost-effective. In other words, it is reasonable to conclude that these actions would be cost-effective in light of the large mass rate of emissions (100 kg/hr of methane or greater) that would be reduced, and the high volume of gas saved. It is highly unlikely that these actions would exceed the \$2,185/ton of methane reduced, which is the highest value we have determined to be cost effective for reducing methane from sources within this source category. In summary, the EPA finds the data demonstrate that the SERP is cost-effective, even though the EPA recognizes that the total emissions reductions that will result from the program are difficult to quantify.

<sup>143</sup> Id. at 74,750.

Agency in reviewing third-party notifications”<sup>144</sup> and requiring completion of root cause analyses within 10 days of a third-party notification—all without an ability to quantify emissions reductions likely to result from the program<sup>145</sup> and with limited cost projections.<sup>146</sup>

Commenter (2283-Endeavor Energy Resources) provides that responding to a notifier's report (even when inaccurate) would require significant time, personnel, and compliance reviews by operators. Based on its own experience, and from discussions with other operators in the Midland Basin, commenter estimates that it can take up to a week of employee time to accurately respond to a detection report from the TCEQ, even if the detected event is based on a misunderstanding of a simple (and legal) maintenance activity. There is a real risk that misguided or inaccurate third-party reports based on misinterpretations of legal activities or misuse of monitoring devices could distract compliance teams from focusing on actual problems or risks within the facility—an acute problem for small businesses with limited personnel and resources like many of the producers in the Midland Basin. Based on its past experience, commenter (2283-Endeavor Energy Resources) also believes that the proposed timelines for initiating and completing a root-cause analysis will be infeasible or overly burdensome for operators and recommends that EPA revise the timelines included in any finalized rule to allow for at least 20 business days to complete the analysis. In addition, EPA concerningly has not conducted any quantification of the costs or benefits of the SERP.<sup>147</sup> At the very least, EPA must do so, and should revise its economic assessments to reflect the costs of responding to outside, third-party reporting, especially on small businesses.

Response II-14-125: EPA acknowledges the commenters’ input. EPA has revised the “root cause analysis criteria” as an “investigation” as detailed in sections X.C.2 and XI.C.4 preamble to the final rule. EPA has maintained the timeline requirements from the December 2022 supplemental proposal in the final rule.

#### 14.4.5.1 Monetary Incentives

Comment: Commenter (2366-BHE) supports developing remote monitoring and measurement technologies and standard methods for technology use. EPA should use IRA funds to support developing the needed program infrastructure. This would be an ideal use of those funds. In addition, other proposed program elements are troubling. For example, EPA should require verification of a purported super-emitter event before information is shared publicly, and third-party participants should be required to abide by that process.

Commenter (2483-INGAA) respectfully suggests that EPA should use funds provided by the IRA to create a process for the methods that should be used with each technology and the qualifications that should be required of a third-party who is approved to conduct monitoring.

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<sup>144</sup> Id. at 74,751.

<sup>145</sup> Id. at 74,747, 74,754.

<sup>146</sup> Id. at 74,752-54.

<sup>147</sup> See RIA, at 25 (“We do not attempt to quantify the impacts of the SERP due to the unpredictable nature of super-emission events, resulting in a lack of specific data on their frequency, intensity, and cost to mitigate.”).

This would be a productive use of those funds, and EPA could re-propose the program after this important work has been done.

Response II-14-126: EPA acknowledges the commenters' input.

Comment: Commenter (2447-Clean Air for the Long Haul) states the EPA should support community programs, including providing financial assistance and technical training to certify members of impacted communities. EPA should deploy and maintain continuous emissions monitoring within fenceline communities using the best available technology capturing a wide range of pollutants, beyond PM<sub>2.5</sub> ensuring that this community-managed data is accepted and offers credible evidence to showcase non-compliance by oil and gas companies. Moreover, there should be immediate follow up on complaints filed by certified community members, swift mitigation, stronger local level regulations and recourse if there is continual non-compliance.

Response II-14-127: EPA acknowledges the commenters' input.

Comment: Commenters (2453-Carbon Mapper and RMI, 2626-Kayrros) state EPA should provide competitive grants and other funding opportunities to ensure the establishment and continuity of third-party observing systems and frameworks for robust identification and notification of facility operators, which otherwise would likely remain limited to philanthropic funding. Potential SERP funding sources include provisions for methane monitoring in the Methane Emissions Reduction Program (see Docket ID No. EPA-HQ-OAR-2022-087).

Commenter (2626-Kayrros) states recent efforts to make data publicly available, such as the Oil & Gas Infrastructure Mapping (OGIM) database developed by the Environmental Development Fund, should allow third-party notifiers to identify the right operator at no cost and to submit the information in a timely manner. Commenter (2626-Kayrros) states third-party notifiers will have to build teams responsible for running the algorithms, validating the results, attributing to a specific operator and issuing notifications in a timely fashion. Moreover, these teams will have to operate outside normal business hours, and particularly on weekends and public holidays. Unless they receive compensation, most service providers may find it difficult to bear the associated costs, in addition to the cannibalization of revenue from the public release of super-emitter data. On that basis, the EPA should consider economic incentives that can attract third-party notifiers to the super-emitter response program in sufficient numbers.

Response II-14-128: EPA acknowledges the commenters' input.

Comment: Commenter (2306-Citizen's Climate Lobby) notes in this paragraph of the rule,<sup>148</sup> there is no mention of monetary reward, despite payment that will be made soon regarding methane charges. The paragraph should insert additional framing regarding monetary reward. This can include language stating "The owner or operator shall send a copy of the notification to the notifier(s) who notified this event and make a payment of \$10,000 divided equally among them. When the Administrator receives the methane charge for the event, the Administrator in

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<sup>148</sup> Proposed Rule, P.25 - 40 CFR 60.5371b(e)(1).

turn shall pay the methane charge for the event, to the notifier(s), divided equally; to the extent it exceeds \$10,000. The notification shall include the requirements in paragraphs (e)(1)(i) through (iv) of this section.”

Response II-14-129: EPA acknowledges the commenters’ input. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. We encourage participation in the Super Emitter Program by third parties, however a reward would be an inappropriate incentive and is not part of the final rule.

Comment: Commenter (2269-Arthur Gershkoff) asks EPA to create incentives for Fossil Fuel companies to partner with the EPA to control these leaks.

Response II-14-130: EPA acknowledges the commenters’ input.

#### ***14.4.6 State, Tribal, Local Air Quality Administration***

Comment: Commenter (2220-WDEQ) is aware of other states that share a number of concerns pertaining to the proposed SERP. Instead of moving forward with the SERP as proposed, the commenter encourages EPA to engage with its state co-regulators to examine existing state frameworks for addressing citizen concerns. State, Local, and Tribal air agencies are more accessible to, familiar with, and responsive to their citizens’ concerns because they are located in and accountable to those communities.

Response II-14-131: EPA acknowledges the commenters’ input.

Comment: Commenter (2193-California Air Resources Board (CARB)) notes that the only reporting to EPA appears to be when the facility owner or operator confirms the super emitter event and EPA only proposes setting up a "document repository" for the notices to operators it receives as well as the reports sent by the owners and operators in response. The purpose of the repository is so the communities, notifiers, and owner/operators may have quick access to the information contained in the notices and reports.<sup>149</sup> There is no discussion as to who is administering the corrective action of the owner/operators, the compliance of the owners/operators, and what responsibility the state agencies have in the program.<sup>150</sup> EPA has only proposed requiring the owner/operator to submit a corrective action plan to EPA or delegated state authority within 30 days of receipt of the notice "that describes the corrective action(s) completed to date, additional measures that they propose to employ to reduce or eliminate the emissions, and a schedule for completion of those measures."<sup>151</sup> Once the repair is

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<sup>149</sup> 87 Fed. Reg. 74,747-74,748 (Dec. 6, 2022).

<sup>150</sup> Ibid.

<sup>151</sup> 87 Fed. Reg. 74,751 (Dec. 6, 2022).



complete, a report is due to both the state authority and EPA within 15 days.<sup>152</sup> Aside from that, there is no clear mention as to a state's role in the SERP.

Commenter (2193-CARB) provides that EPA proposes treating a super emitter emissions event as a separate and distinct source of emissions under section 111 of the CAA.<sup>153</sup> The argument here is that super emitter events occur due to facility noncompliance and equipment malfunction as opposed to leaks that may occur due to maintenance needs during proper operations.<sup>154</sup> EPA must therefore "(1) 'determine[ ],' taking into account various factors, the 'best system of emission reduction which ... has been adequately demonstrated, (2) ascertain the 'degree of emission limitation achievable through the application' of that system, and (3) impose an emissions limit on new stationary sources that 'reflects' that amount." (West Virginia v. EPA (2022) 142 S. Ct. 2587, 2601.) Implied in this analysis is an analysis of the overall costs. (Id. at 2604.) EPA has thoroughly vetted the costs and benefits of the proposed SERP and found that it is not only feasible to implement but should have cost benefits for that outweigh the cost of compliance for the facilities who are losing more than 100 kg/hr of gas as well as significant beneficial impacts on the environment in methane emissions reduction.<sup>155</sup> However, EPA is has not clearly stated costs the states would have to absorb in administering the SERP.

Commenter (2193-CARB) states that the proposed SERP provides a solid start to detecting super emitters between periodic inspections while ensuring transparency to the affected communities. EPA also has a central role here by approving the third-party notifiers (Notifiers), maintaining the notices, establishing the guidelines, and maintaining the reports. Given all that, Commenter (2193-CARB) encourages EPA to take the burden of administering the enforcement and compliance portions of the program to ensure consistent application across the regulated entities. While it makes sense for the affected state agencies to receive copies of the notices and reports for the enforcement of their local rules and regulations, the states should not be involved in managing or approving the Notifiers, deciding whether the owner/operators corrective action plan meets EPA's standards, or ensuring that the corrective action is complete to EPA's satisfaction.

Commenter (2193-CARB) notes that, for instance, CARB's regulation states each day, or portion thereof, an owner/operator is out of compliance with any of the oil and gas regulations (17 Cal. Code Reg. §§ 95668-95674) counts as a separate violation.<sup>156</sup> It is clearly a statutory scheme established to encourage swift compliance through monetary penalties. In comparison, EPA's SERP does not assess penalties, but only requires corrective action. Therefore, if California's 111(d) Plan had to suddenly address the implementation and enforcement of regulations ensuring the corrective action taken by the owner/operator was to EPA's satisfaction within 10 days, that the corrective action reports met EPA's standards, and/or that Notifiers were performing as required, this would involve the propagation of numerous regulations. Additional regulations require more discussion between stakeholders, legislators, and community members to satisfy

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<sup>152</sup> Id.

<sup>153</sup> 87 Fed. Reg. 74,752 (Dec. 6, 2022).

<sup>154</sup> Id.

<sup>155</sup> 87 Fed. Reg. 74,752-74,753 (Dec. 6, 2022).

<sup>156</sup> 17 Cal. Code Reg. § 95675.

the administrative process. Furthermore, each state would be required to "re-invent the wheel" as it propagated these regulations, resulting in uneven enforcement and implementation across the country.

Commenter (2193-CARB) supports EPA's program design to take the responsibility of managing the SERP by setting standards for and approving the Notifiers and establishing the reporting system. But improvements can be made. Commenter (2193-CARB) recommends that EPA also take the responsibility of ensuring the Notifiers carry out their duties appropriately, approving the corrective action plans, and ensuring the owners/operators comply with not only the reporting requirements, but the corrective actions as well. The Notifiers should send notices of violation to the owner/operators, EPA, and the designated state agencies so that all entities have record of the concern and EPA can upload the notice into the document repository. The owner/operators should then provide their corrective action plans and post-repair reports to both the EPA and the designated state agency within the 30 and 15-day time periods EPA has proposed for EPA to upload into the document repository. Thereafter, the commenter recommends EPA enforce whether the corrective action plan and report is submitted in a timely manner and meets EPA's requirements. The state agency would be charged with enforcing its own provisions, separate and apart from EPA's responsibility, to ensure the owner/operator promptly complies with the repair of the root cause for the super emitting event.

Response II-14-132: EPA acknowledges the commenters' input. EPA is developing a centralized reporting portal to handle receive super emitter reports. The final rule, as described in Section X.C.2 of the preamble has universal reporting requirements which all affected owner or operators who receive a notification must submit. While this information will be submitted to the EPA, the system will be designed to make the data available to all stakeholders, including the state, local, and tribal authority.

Comment: Commenters (2225-WESTAR, 2241-Public Lands Policy Coordinating Office, Utah Department of Natural Resources, 2248-NDPC) are concerned that the proposed SERP is a deviation from the typical delegation of authority to state, Tribal, and local air agencies.

Commenter (2225-WESTAR) members have concerns that this program could convolute the state, Tribal, and local air quality compliance and enforcement process and add to misinformation maladies. Instead [of the proposed SERP design], Commenter (2225-WESTAR) offers that there are many options available for EPA to leverage remote sensing and satellite data to track methane emissions and detect super emitter events. EPA may wish to augment its own detection programs with a focus on improved data accessibility and transparency, making information more readily and easily available for the public to access and understand, in ways that productively enable their engagement.

Response II-14-133: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. If an owner or operator identifies a deviation of an applicable standard as part of their follow-up investigation, they would be subject to the

recordkeeping and reporting requirements in NSPS OOOO, OOOOa, OOOOb, and/or EG OOOOc.

Comment: Commenter (2241-Public Lands Policy Coordinating Office, Utah Department of Natural Resources) provides that, in an area where there is already multiple layers of regulations and responsible agencies, adding a third-party may add to the already confusing mix and lead to actually less effective compliance and enforcement of the regulations. It would be better to allow the state, Tribal and local air agencies to work with current requirements and the new proposed flexibility with leak detection and monitoring with new evolving technologies to develop their programs and request third-party involvement if they have the need. This proposed regulatory approach should be removed from this proposal and perhaps the new funding opportunities from EPA can be used to support this idea, but with the states and tribe's control.

Commenter (2248-NDPC) notes that the North Dakota Department of Environmental Quality (NDDEQ) responds to 100 percent of all complaints. Each complaint is investigated, and when issues are found, NDDEQ works to address the identified issues quickly with all parties. Any issued notice of violation and penalty are publicly available. Commenter contends that the Super emitter program would circumvent the state agencies' rights to administer their state specific programs and could add to burden to the agency by having to address emissions that may be erroneous (errors in the technology since they are not ground level or direct measurements) or even where the emissions are authorized.

Response II-14-134: EPA acknowledges the commenters' input. EPA has revised the rule to include EPA in a centralized role, to approve the technology used in the Super Emitter Program, certify third party notifiers, and to verify the data before providing notifications to an owner or operator. There is no obligation on a state, local, or tribal authority to address data submitted to this program.

## **14.5 Third-Party Notification**

### ***14.5.1 General Support and Opposition***

Comment: Commenters (2028-Westmoreland Marcellus Citizens' Group, 2195-Environmental Health Project, 2212-On behalf of the Union of Concerned Scientists, 2244-Norma Kline, 2302-Texas State Representatives, 2303-National Tribal Air Association (NTAA), 2392-Earthjustice et al., 2408-Colorado Local Government Coalition, 2409-BP America Inc., 2410-California Office of the Attorney General et al., 2433-EDF et al., 2444-NAACP, 2626-Kayros, 2627-BCI) strongly support EPA's SERP to address super emitter events through third-party monitoring. Empowering frontline communities with resident-led monitoring projects will be a step forward in terms of how the public is able to engage with neighboring industry. EPA needs to provide a clear pathway for communities and individuals to participate in the SERP.

Response II-14-135: EPA acknowledges the commenters' input; the rule does not limit the participation from communities or individuals.

Comment: Commenters (2195-Environmental Health Project, 2217-Religious Action Center of Reform Judaism, 2410-California Office of the Attorney General et al.) recommend EPA strengthen community monitoring, in part by providing a clear pathway for communities and individuals to participate and engage in the SERP.

Commenters (2392-Earthjustice et al., 2410-California Office of the Attorney General et al.) add EPA should ensure that the technologies that may be used to detect a super emitter emissions event are not so restrictive that they prevent community groups from participating as third-party notifiers. For example, EPA should leverage publicly available satellite data in the SERP by permitting third parties who may not have access to remote-sensing technologies to submit notifications based on publicly available satellite monitoring data.

Response II-14-136: EPA acknowledges the commenters' input. The requirements for third parties have been revised in the final rule and are described in section X.C.2 of the preamble of the rule.

Comment: Commenter (2334-Liveable Arlington) states EPA has admitted that current staff does not have the capacity to regulate 1.5M facilities. However, there are 17 million people living in the shadows of oil and gas extraction who want to help regulators fill in their gaps. Regulators must work with these frontline communities to most efficiently and effectively use their limited capacity.

Response II-14-137: EPA recognizes the commenters' concern.

Comment: Commenter (2453-Carbon Mapper and RMI) recommends EPA require third-party reporters make every technical and economically feasible effort to report quantitative emission rate estimates and uncertainties for each source reported to operators. This can help track the amount of methane mitigated by repair actions and support assessment of the overall impact of the SERP program. Commenter (2453-Carbon Mapper and RMI) recommends EPA consider leveraging quantitative emission estimates from SERP reports to support local air-quality and environmental justice assessments for front-line communities in the proximity of super-emitter events.

Response II-14-138: EPA acknowledges the commenters' input, and the final rule has been revised to require the third-party notifier to report the emission rate and uncertainty bounds.

Comment: Commenter (2433-EDF et al.) agree super emitter events should generally not occur at a site that is well operated, well maintained, and that has implemented EPA's proposed standards. Independent third-party monitoring data showing such emission events will therefore likely indicate major problems, regulatory violations, and events that endanger nearby communities. This type of program may also serve as a valuable preventative measure, creating additional incentives for operators to keep their sites maintained and properly operated so such events do not occur. And perhaps most importantly, publication of these emission events will allow nearby community groups to take appropriate protective action. It will also build trust in the entire enterprise of driving down methane emissions, which currently is lacking due to the

large discrepancy between reported emissions and stated actions and the frequent large emissions typically uncovered in field observations.

Commenter (2410-California Office of the Attorney General et al.) adds a third-party who chooses to become an EPA-approved notifier would do so on a voluntary and uncompensated basis. This means that private parties with access to remote sensing technologies may have few incentives to actively participate as third-party notifiers. Communities living near oil and gas facilities, on the other hand, will have a vested interest in identifying super emitter emissions events in order to protect their own health and safety, and such communities should be empowered to identify and report super emitter emissions events by relying on reliable, publicly available data.

Response II-14-139: EPA acknowledges the commenters' input.

Comment: Commenter (2394-Earthworks) note state regulatory and enforcement agencies are inconsistent and insufficient in how they respond to public complaints about methane and air pollution. Limited budgets mean that most agencies that regulate the oil and gas industry are underfunded and short-staffed, and rarely have enough employees to adequately enforce our state and federal clean air laws. State regulators fully admit that they do not currently have the resources to adequately protect the public from oil and gas pollution. "One hundred percent, we are not where we need to be to hold the industry accountable," said James Kenney, NMED Secretary in a January 22 news article. "I have more violations than I have staff to work on them," he continued. "That's a huge struggle and point of frustration."<sup>157</sup>

Commenter (2394-Earthworks) notes the EPA has also admitted that current staff does not have the capacity to regulate 1.5M facilities. Broad inclusion of third parties in the SERP can allow for efficient and effective use of EPA staff's limited capacity. The enforcement process for this rule is going to require engagement from third parties and communities who are directly impacted. In order to fully achieve the climate and environmental justice goals laid out by this Administration, they must be able to meaningfully engage in the regulatory process, file complaints about emissions detected, and be taken seriously by regulators.

Commenter (2299-NEI Investments) adds super emitters can be missed by standard LDAR procedures, so the problem does require a creative solution, and involving a broader set of stakeholders in identifying these problem sources is worth exploring.

Response II-14-140: EPA acknowledges the commenters' input.

Comment: Commenters (2247-Ohio Environmental Protection Agency, 2258-MSA, 2282-Kinder Morgan Inc., 2283-Endeavor Energy Resources, 2442-Wyoming Coalition of Local Governments) understand the desire to locate large scale leaks from oil and gas operations.

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<sup>157</sup> Source NM, "NM leaders promote hydrogen production despite questionable environmental benefits," January 2022, <https://sourcenm.com/2022/01/05/nm-leaders-promote-hydrogen-production-despite-questionable-environmental-benefits/>.

However, this program would, in essence, delegate to an outside entity the ability to apply and enforce U.S. EPA requirements over and beyond the existing mechanism for citizens to enforce the provisions of the CAA through Section 304. Commenter (2247-Ohio Environmental Protection Agency) adds although there may be newer technologies that are becoming available to identify large leaks, outside private individuals should not become the enforcement arm of U.S. EPA. An additional concern relates to single family or small business-owned wells. Are they expected to know what they should do if a third-party determines that their well is a super emitter? How will they know that they must act to fix a leak within 10 days? Will they be able to get a pipeline/well repair person out within the 10-day period? Commenter (2247-Ohio Environmental Protection Agency) does not believe many of these small operators will have the knowledge or resources to know what to do under a super emitter situation.

Response II-14-141: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. The intent of the program, as noted in the final rule, is primarily compliance assurance and that information is passed along in a timely manner to owners and operators.

Comment: Commenter (2442-Wyoming Coalition of Local Governments) states the EPA approving and otherwise verifying a third-party notifier's qualifications and special expertise or allowing a facility owner or operator to challenge the notifier's data or qualifications does not resolve the issue of the EPA granting the notifiers this specific, regulatory authority. Id. at 74749-74750. The operator would still have to address specific notifications from third-party notifiers by either taking corrective actions or having to file objections to the data with the EPA. For the EPA to properly oversee the program, it would need to retain the ability to review and verify the information collected from third-party notifiers before requiring specific actions from facility operators to resolve the claimed emissions.

Response II-14-142: EPA acknowledges the commenters' input. EPA has revised the final rule to include EPA in a central role in receiving reports from third parties and providing notifications to an owner or operator, if necessary. The final rule does not grant third-party notifiers with any regulatory authority.

Comment: Commenters (2177-Ute Indian Tribe, 2283-Endeavor Energy Resources) believe allowing a third-party notifier will create excessive work for both the administrator, or delegated authority, and the operator to substantiate and investigate all claims made for super emitter events. This is unnecessary, as there are already systems in place to allow third parties to file complaints or notify the Administrator, or delegated authority, if they believe there is a potential issue. It also creates an excessive burden on the operator to be required to take action on all third-party notifications.

Response II-14-143: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or

operator of an applicable oil and gas facility. The Super-Emitter Program, as described in section X.C of the preamble of this rule is designed to put the burden of demonstrating the occurrence of a super emitter event and its location on the third-party notifier and notifications to an owner or operator only occur after the EPA evaluates the data. These steps are in place to minimize any erroneous notifications and to ensure owner or operators are being provided with actionable data.

EPA may use any credible evidence to establish a violation. If an owner or operator, upon conducting the required investigation, determines that a deviation from an applicable standard has caused the super emitter event, then the owner or operator must comply with the requirements in NSPS OOOO, OOOOa, OOOOb and/or EG OOOOc to correct and report the deviation.

Comment: Commenter (2409-BP America Inc.) states the fact that a release of methane has been detected at a rate exceeding 100kg/hr does not necessarily mean that any standard has been exceeded or that any violation has occurred at any particular facility. It is also important that the program be designed to incentivize prompt, proactive actions on the part of operators. Therefore, Commenter (2409-BP America Inc.) believes it is important that data provided by responsible operators to EPA in response to a third-party notice is not used punitively against the operators. In particular, EPA should consider revising the program so that any documents shared with EPA, for example, articulating corrective actions taken, are subject to a safe harbor provision that prevents EPA (or, to the extent feasible, other entities) from using information in the document for purposes of enforcement, e.g., a notice of violation (NOV) or a civil suit.

Response II-14-144: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. The Super-Emitter Program, as described in section X.C of the preamble of this rule is designed to put the burden of demonstrating the occurrence of a super emitter event and its location on the third-party notifier and notifications to an owner or operator only occur after the EPA evaluates the data. These steps are in place to minimize any erroneous notifications and to ensure owner or operators are being provided with actionable data.

EPA may use any credible evidence to establish a violation. If an owner or operator, upon conducting the required investigation, determines that a deviation from an applicable standard has caused the super emitter event, then the owner or operator must comply with the requirements in NSPS OOOO, OOOOa, OOOOb and/or EG OOOOc to correct and report the deviation. The Super Emitter Program does not create a safe harbor for violations of Clean Air Act regulations.

Comment: Commenter (2288-NDDEQ) states if EPA intends to be the administrator of the super emitter program, then the commenter has similar concerns using this interpretation. While the initial notification from the approved third-party is required to be reported to both EPA (as Administrator in this case) and to any delegated authority, the requirement for any corrective action plans and follow-up reports are only required to be reported to EPA. Again, the proposed regulations do mention that upon receipt, EPA "shall make such report publicly available" per

\$60.5388c(e)(4), however there is no guaranteed timeline of when that availability will occur. This lack of follow-up will complicate the commenter's efforts to ensure proper ground truthing and resolution of super emitter events. Commenter (2288-NDDEQ) requests that, like the initial notifications, such documents also be submitted to the delegated authority.

Response II-14-145: EPA acknowledges the commenters' input. Requirements for public availability are discussed in Sections X.C of the preamble of the final rule. As part of this final rule, EPA will public owner or operator notifications and the response to these notification via the Super Emitter Portal.

Comment: Commenter (2389-ACC) maintains that operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources. If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available if a potential issue is observed. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. Commenter (2389-ACC) does not consider it unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly react to third-party activity.

Response II-14-146: EPA disagrees that it is necessary or feasible for certified third parties to provide advanced notice of activity. With respect to the needs of the owner or operator, the Super Emitter Program, as finalized, is designed to provide actionable (*i.e.*, EPA verified) data of a super-emitter event that would trigger a response by an owner or operator. The revisions to the super emitter program, including timelines are described in Section X.C.2 and XI.C.2 in the preamble of this rule.

#### ***14.5.2 General Recommendations and Clarifications***

Comment: Commenters (2168-Indiana Oil and Gas Association (INOGA), 2172-Kentucky Oil and Gas Association) ask what resources are available to quantify the emissions rate of 100 kg/hr or greater? To quantify a leak rate in mass/time, a composition analysis and flow rate are both required. Is mobile equipment available to provide this data to the owner / operator in a reasonable period? How does the EPA representative gain access to the location to collect samples for composition and flow rate without trespassing? Does EPA have the authority to enter onto private property to sample gas composition or flow rate without permission? Does EPA have the authority to touch the assets from an oil and gas operation without permission from the operator? Does EPA have the authority to collect the gas for sampling? How is this not theft? EPA or their representative is taking something that does not belong to them, and they have not been granted permission to take. There are many challenges to this concept that EPA will need to address prior to implementing this type of program.



Response II-14-147: EPA recognizes the commenters' concern and we have revised the Super Emitter Program to require EPA approval of methane detection technology and to include requirements that certified third parties cannot access approved applicable sites and doing so would lead to the removal of their certification.

Comment: Commenter (2333-LongPath Technologies, Inc) suggests that EPA exempt from SERP requirements those sites that employ quantitative continuous emissions monitoring with ability to monitor all equipment on site (e.g., stick flares, tall tanks, yard piping). At a minimum, the commenter suggests that EPA allow those operators who have valid quantification continuous monitors with full-site coverage on a site to use that data to respond to super emitter program alarms and to be exempted from public posting of leaks.

Commenter (2333-LongPath Technologies, Inc.) states operators with valid continuous monitors (with full site coverage) will very likely already have noted and mitigated super emitter events before even receiving notification of the event from the super emitter program. Therefore, operators using continuous monitoring will be at risk of additional incurred costs of effectively responding to these events twice, first via the appropriate find-and-fix using continuous data and second via the unnecessary additional data collection and reporting under the SERP. The operator would further be subject to negative public regard, despite having taken immediate action by using continuous monitoring.

Response II-14-148: EPA acknowledges the commenters' input. The final rule has included the use of approved continuous monitoring systems in the follow-up investigation to confirm the presence or absence of a super-emitter event.

Comment: The commenters (2179-KIOGA, 2348-Energy Workforce and Technology Council) state there must be training requirements for submitting parties, and producers need to be given adequate time to complete any required compliance actions after notification. Commenters are concerned some third-party notifiers may be inadequately trained to detect methane leaks. The commenter recommends that third-party notifiers be required to have appropriate training/certification in order to validate emissions events.

Response II-14-149: EPA recognizes the commenters input and the final rule now includes the third-party be adequately trained to evaluate data generated by the specific approved methane detection technology used for their surveys, these requirements are discussed in section X.C.2 of the preamble to this rule.

Comment: Commenter (2279-U.S. Small Business Administration) states EPA should design this program to make clear that EPA is not delegating enforcement authority and that the role of the third-party notifier is limited to the narrow specifications of this program. Towards that goal, the commenter recommends the following specific provisions.

- Make a clear prohibition on trespassing on oil and gas production sites, with withdrawal of approval to third-party notifiers for repeated violations. Operators need assurances that

third parties will not interpret their participation in this limited program as an invitation to engage in further investigation or conduct their own inspections.

- Require third-party notifiers to submit reports of super emitter events to the relevant regulatory authority, not directly to the operator. There is no uniform reliable means to determine ownership of a site remotely, and operators should not be required to engage in costly regulatory compliance based on a third-party's self-certification.
- Emphasize that reports of super emitter events are not evidence of a violation of the CAA permit or the regulations.
- Provide a safe harbor against enforcement for methane emissions reported and resolved in response to a report of a super emitter event.
- Withdraw approval after three erroneous reports, whether to the same operator or not.

Commenter (2345-GHGSat Inc.) comments on the proposed framework for the SERP, which is delineated in the following five points:

- 1) The qualified third-party permitted to submit notifications must be certified by the EPA as having appropriate experience and expertise. The commenter agrees with this point.
- 2) The qualified third-party may only use certain remote detection technology approved by the EPA for use in the SERP. The commenter agrees with this point. Any new development or use of different technology by a third-party notifier should go through the evaluation process.
- 3) The EPA would establish the threshold defining what emissions events detected by the qualified third parties would trigger any obligation on the part of the owner and operator under the program. The commenter believes that this point should be clearer, since the definition of a super emitter event is proposed to be emissions greater than 100 kg/hr. Hence, this point should establish that.
- 4) The EPA has prescribed the specific factual information that must be included in any appropriate notification provided to an owner or operator. The commenter (agrees with this point and invites the EPA to consider the comments provided in the notification requirements section of this document.
- 5) The EPA has proposed a mechanism for owners and operators to seek a revocation of a notifier's certification from the EPA should they establish that more than one notification contained demonstrable errors. The commenter believes that this point requires further clarification as to what constitutes a demonstrable error. Also, the "strike system" mentioned in the proposed rule talks states that more than three notifications with errors, however, here mentions more than one notification with error. This discrepancy should be resolved. Lastly, it also needs to state the contemplated timeline for these erroneous notifications to accumulate.

Response II-14-150: EPA acknowledges the commenters' input, the Super Emitter Program has been revised to include EPA in a centralized role and has clarified the requirements and responsibilities of the third-party notifiers, these are detailed in section X.C.2 and XI.C.2 of the preamble to this rule.

Comment: Below Commenter (2428-API) has outlined suggestions on the appropriate steps to be included in a repropose framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA’s goals for transparency within the program.

1. The third-party completes approval certification process by EPA for inclusion in SERP and becomes “certified or re-certified”.
2. Certified third party<sup>158</sup> notifies EPA of planned monitoring, including submittal of a monitoring plan, at least 30 business days prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of the commenter’s letter.
3. EPA reviews the certified third parties’ monitoring plan for approval or disapproval.
  - a. If approved, EPA notifies the impacted operators at least 7 business days prior to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a “pre-notification” to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
  - b. This “pre-notification” may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4. Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has 2 calendar days to provide data as defined in §60.5371b(b) to the EPA.
5. If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within 3 calendar days of verification of third-party monitored data.<sup>159</sup>
6. Operator(s) will initiate an investigative analysis within 5 business days of receipt of data from EPA and complete the investigation within 10 business days of receipt of the data from EPA.
  - a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that operator will provide “no action required” demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).
  - b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs within 15 calendar days after completing the investigative analysis.

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<sup>158</sup> For the purpose of these comments when we reference a ‘third-party’, ‘certified notifier’ or ‘certified third-party’ we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.

<sup>159</sup> The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

7. All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting." Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

Commenter (2428-API) states the timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

Response II-14-151: EPA acknowledges the commenter's input and with many concerns the commenter raises, including but not limited to the with the need to have EPA in a centralized role reviewing super-emitter data, the timeliness of submittals by the third-party, and the identification of an owner or operator of a super-emitter event without confirmation of attribution. The Super Emitter Program has been revised in the final rule, these revisions are detailed in section X.C and XI.C of the preamble to this rule.

EPA has not chosen to require third parties to provide owner or operators of a notification of when they choose to conduct a survey as we consider this to be burdensome and, in some cases, technically feasible. Approved third party may choose to volunteer this information to the owner or operators.

### ***14.5.3 Operator Identification and Notices***

Comment: Commenter (2433-EDF et al) largely supports EPA's proposed six criteria for valid detections that would then trigger a response requirement for the responsible operator. The commenter also agrees that these upfront criteria, paired with the technology and independent third-party notifier approval process, obviate the need for additional data review by EPA after detection and support direct publication and notification to operators.

The notification criteria are generally appropriate; however, Commenter (2433-EDF et al) suggests a few modifications. The second criteria should typically be boilerplate and could be developed by EPA during the third-party notifier approval process. Only when a notifier is deploying multiple technologies or methods would this need to change. The fifth criteria should

be removed, and the date and time requirements be instead included in the first criteria alongside geographic coordinates. The commenter believes the latter portion of the fifth criteria is unnecessary and is already encompassed in criteria one and four. In addition, the commenter supports the signed certification requirement and urge EPA to make similar requirements applicable to operators when submitting information about their response to the notification.

Importantly, as part of the standards applicable to well sites, centralized production facilities, and compressor stations, Commenter (2433-EDF et al) argues EPA should require operators to submit exact geographic locations of sites in their initial and annual reports. EPA has already proposed to require this information in the alternative LDAR standards at section 60.5398b and should make similar requirements uniformly applicable. This information should then be used to accurately identify operators and sites responsible for detected emission events.<sup>160</sup> Using operator-submitted geographic information, EPA could design a portal for submission of notifications that would directly match the submission with the responsible operator.

Response II-14-152: EPA acknowledges the commenters', the Super Emitter Program has been revised to include EPA in a centralized role and has clarified the requirements and responsibilities of the third-party notifiers, these are detailed in section X.C.2 and XI.C.2 of the preamble to this rule.

Comment: Commenter (2305-The Williams Companies, Inc.) notes the proposed criteria for how the EPA will certify third party entities as 'notifiers' lacks transparency and specific details. Appropriate experience and expertise must be described more fully and should be commensurate with the requirements proposed for industry personnel and other regulatory bodies with delegated authority. Additionally, the regulated community should have access to technical data on the proposed monitoring technology from the specific monitoring entity along with approved protocols and procedures from that entity.

Response II-14-153: EPA acknowledges the commenters' input; EPA has expanded the criteria a candidate third-party must meet to receive certification. Likewise, the technology used for this program must be approved through the same criteria in the alternative test method for methane detection technology in §5398b(d). These revisions are detailed in section X.C.2 and XI.C.2 of the preamble to this rule.

Comment: Commenters (2177-Ute Indian Tribe, 2202-TXOGA, 2213-Occidental (Oxy), 2389-ACC, 2409-BP America Inc., 2428-API, 2453-Carbon Mapper and RMI) state EPA should require third-party reporters to make every economically feasible effort to identify the nearest potential facility operator based on available asset ownership information. EPA (or Administrator) should review notifications from third parties to ensure that the third-party is an approved notifier.

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<sup>160</sup> See Hmiel et al., Empirical Quantification of Producers in the Permian Basin, supra note 215 (describing the process of matching aerial observations to sites and operators using Enverus Prism and GIS data).

Commenters (2177-Ute Indian Tribe, 2202-TXOGA, 2248-NDPC, 2399-GPA Midstream Association) question how third-party monitoring entities are going to know who the operator is, or how to contact the right people if the facility is covered by NSPS OOOOb, contending this lack of information is a burden on the state agency's resources as well as the Operator's.

Commenter (2202-TXOGA) notes that an inherent assumption in the preamble discussion is that a notifier can reliably identify the operator of a site with a super-emitter. In reality this is unlikely, and certainly not reliable, because while there may be databases of well locations, similar databases/maps of other types of facilities such as tank batteries and compressor stations do not exist. Notifiers can easily make incorrect assumptions, such as potentially concluding that if a particular well operator is known, then nearby/adjacent facilities necessarily have the same operator. Beyond this simple example are other opportunities for misinformation/misidentification of operators, such as plume drift and asset ownership transfers. As a result, operators could be forced to expend significant resources redirecting and ultimately delaying response to a super-emitter.<sup>161</sup>

Commenters (2177-Ute Indian Tribe, 2202-TXOGA, 2389-ACC, 2399-GPA Midstream Association) note it is important for notifications to be sent to the correct person at the operating company. When there are short response deadlines, there cannot be delay in transmitting the information to the responsible person at the company. If EPA is going to implement this program notwithstanding the concerns raised by numerous commenters, it is critical that third-party notifiers be required to communicate with specific point of contact information at the company (which EPA might consider assembling).

Commenter (2399-GPA Midstream Association) adds without such guidance, owners and operators may end up exceeding these deadlines because the third-party notifier sent the notice to the attention of a general community relations employee that does not understand the significance of such a notice, former employees, employees on vacation, or any number of company contacts that are not designated to handle such environmental concerns. The rule should not, for example, allow notifiers to rely on phone numbers or other contact information posted on facility locations or general contact information as the formal contact for receiving official notice on behalf of the operator/company.<sup>162</sup> The contact could, for example, be the same person or contact that is the designated representative for Subpart W. EPA should also detail how changes to the company contact would be handled when the named contact(s) are not at work (PTO/Vacation/Sick leave) or have been reassigned or retired. The rule should also address collocated facilities to avoid undue confusion, given the short response time, and specify the responsible party for a joint venture.

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<sup>161</sup> TXOGA notes that the existing experience of its members with information provided from EPA to sites has often included videos from sites not actually owned by the recipient of the video. This demonstrates that sufficient oversight is needed to prevent third-party claims from demanding significant resources to prove that the information provided is not associated with the site at issue or presents information otherwise not relevant to an emissions event.

<sup>162</sup> The complexity of providing notice to a company or operator is a further reason why GPA Midstream had proposed in its previous comments that any private party notice should be handled through the regulators, not by a direct action from another private party. Notifications would come to the agency first and then sent to the company.

Response II-14-154: EPA acknowledges the commenters' input; EPA has revised the rule to require third parties to submit data to the EPA and EPA will provide the notification to the owner or operator. As described in Section X.C.2 and XI.C.3 of the preamble to the rule, the third-party notifier must provide a complete report including location and potential attribution, as part of EPA's review we will confirm the attribution and ensure the notification is being sent to correct recipient.

Comment: Commenter (2403-The Petroleum Alliance of Oklahoma) argues the Proposed Rule lacks information on how multiple third parties will avoid monitoring the same area and creating multiple notices to the operator for the same event, it fails to address how third parties will know if an emission is permitted or not, or even if it's an affected facility.

Response II-14-155: EPA recognizes the commenters' concerns; EPA find it important to pass information regarding large emission to owner or operators as soon as possible. In the final rule, if the notification provided to an owner or operator identifies a facility not subject to NSPS OOOO, OOOOa, OOOOb, and/or EG OOOOc, no further investigation is required and the owner or operator would be subject to limited reporting requirements.

Comment: Commenter (2428-API) argues third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.

Response II-14-156: EPA acknowledges the commenters' input, in the final rule, EPA will be providing notifications to the owner or operators and if multiple reports come into the portal in short succession, EPA may only provide a single notification to an owner or operator with information from both reports. EPA finds it important to provide multiple reports of a super-emitter event as it provides valuable information to the owner or operator on persistent emission events so they can be resolved.

Comment: Commenter (2428-API) argues formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.<sup>163</sup> The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

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<sup>163</sup> If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

Commenter (2409-BP America Inc.) encourage EPA to create an online registry with official contact information provided by operators and certified third parties, to help facilitate communications between EPA, third-party notifiers, and operators. The commenter believes that a registry of operators and certified third parties is needed to ensure that all parties participating in the SERP can promptly and effectively communicate with each other. This registry could be created and maintained by EPA and be made available on EPA's website. Additionally, operators and third parties could be responsible for reviewing contact information annually and updating it as necessary.

Response II-14-157: EPA acknowledges the commenters' input and as explained in section X.C.2 and XI.C.3 of the preamble of this rule, EPA is setting up a super emitter portal to handle incoming information and for reporting on notifications provided to owner or operators and their applicable responses.

Comment: Commenter (2428-API) suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within §60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

Response II-14-158: EPA recognize the commenters' input and EPA has revised the requirements for investigations and reporting consistent with some the recommendations in this comment, these revisions are detailed in Section X.C of the preamble of this rule.

EPA has also clarified when an event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb, or a state or Federal plan implementing EG OOOOc) as detailed Section X.C.1 and XI.C.1 of the preamble of the final rule.

#### ***14.5.4 Approval & Removal of Third-Party Notifiers***

Comment: Commenters (2410-California Office of the Attorney General et al., 2433-EDF et al.) support EPA's proposed pre-qualification requirements for independent third-party notifiers, which the commenter believes are central to the effectiveness of the program and ensuring safety and data veracity. These qualifications would include technical expertise in the specific technologies, the detection methodologies, and the necessary interpretation and analysis of the data collected. These criteria are appropriate, and EPA should not create overly restrictive standards that would unnecessarily limit participation. Requirements for third-party notifiers should generally align with and not be more restrictive than requirements for deploying advanced technologies in the LDAR program.



Response II-14-159: EPA agrees with the commenter and has revised the requirements for third-party notifier criteria for certification to include technical training in the specific technology used and documented data review processes to ensure data provided is accurate and defensible.

Comment: Commenter (2453-Carbon Mapper and RMI) states EPA should provide flexibility in certifying reporting organizations under the SERP including allowing both data providers and reporting organizations meeting the agency criteria to be considered “third parties”.

Response II-14-160: EPA recognize the commenters’ input, the only restriction from being a third-party notifier is that they are not the owner or operator of the site where the super-emitter event is detected.

Comment: Commenter (2626-Kayros) states EPA should consider the global context for methane data. Consistency on data sources across different jurisdictions will be important to minimize the burden of compliance among energy companies and to communicate with the wider public. On that basis, the EPA could expedite the approval of third-party notifiers that have already been vetted by other respected entities such as the International Methane Emissions Observatory (IMEO) and the International Energy Agency. In particular, IMEO has implemented a super-emitter monitoring system that is similar to the proposed super-emitter response program, and it seems reasonable to assume that EPA and IMEO will have data providers in common.

Response II-14-161: EPA acknowledges the commenters’ input; however, the EPA will not delegate the authority of this program to other agencies.

Comment: Commenters (2237-Industrial Commission of North Dakota, 2288-NDDEQ) ask will EPA be maintaining a list of all approved third-party notifiers, or will every delegated authority have to maintain their own lists? Does the approval apply nationwide, i.e., would a third-party notifier approved by Texas automatically be an approved notifier in North Dakota? Likewise, does the removal of approved notifier status apply nationwide, i.e, if North Dakota removes a third-party notifier from the approved notification list, would that third-party automatically lose their approval in California?

Commenter (2453-Carbon Mapper and RMI) recommends EPA establish and make available to all approved third-party reporters a list of operator-provided points of contact with contact information to facilitate timely and accurate notification. Commenter (2345-GHGSat Inc.) believes that a registration system will allow the proper identification of qualified third-party notifiers. Hence, commenter (2345-GHGSat Inc.) agrees with the EPA’s intention of creating and maintaining a public list of approved qualified third-party notifiers.

Response II-14-162: EPA will maintain a list of all certified third parties and will maintain the delegation to certify or de-certify these third parties. Candidate third parties must meet a specific set of criteria to be certified, including documented procedures for identifying an owner or operator of a site where a super emitter event has been identified.

Comment: Commenters (2345-GHGSat Inc., 2410-California Office of the Attorney General et al., 2453-Carbon Mapper and RMI) argue EPA should carefully review and elaborate on proposed criteria for removing approval of a third-party reporter for participation in the SERP program, particularly regarding the definition of “demonstrable errors”. For example, if an owner/operator claims that a third-party reported super-emitter did not exceed the 100 kg/hr threshold, EPA should require counterevidence with equivalent or better measurement technology based on simultaneous observations (since EPA recognizes that source intermittency is not grounds for error).

Commenter (2345-GHGSat Inc.) states there must be a formal and unambiguous definition of what constitutes a “demonstrable error”. For example, the intermittent nature of emissions could mislead an operator about the validity of an assessment.

Commenters (2306-Citizen's Climate Lobby, 2444-NAACP) note on P.21 - 40 CFR 60.5371b(a)(4) an approved notifier can lose its approval if it reports a site 4 times with “demonstrable error.” Proving errors is itself subject to error, so this rule chills reports after the first 3, which leaves future years unreported. EPA should change “more than three notices” in the rule, to “more than one notice per month” or “more than three notices per half-year.”

Commenter (2410-California Office of the Attorney General et al.) argues operators will generally have access to much more data about their own operations than third parties using remote-sensing technologies, so it is important that EPA does not permit operators to undermine the validity of third-party notifications on those grounds alone. The commenter suggests that an error should only be considered “meaningful” if it results in false positive (i.e., the identification of a super emitter emissions event when no such event occurred).

Commenter (2410-California Office of the Attorney General et al.) continues, EPA should clarify the process and schedule for an operator to challenge the validity of a third-party notification. The commenter suggests that if an operator believes a notification contains meaningful demonstrable error (and consequently, that a super emitter emissions event did not occur), the operator must submit a report to the EPA within 10 calendar days of receiving the notification, and simultaneously submit a copy to the third-party notifier. The third-party operator would then be provided an opportunity to respond, and EPA would ultimately make a determination as to whether the notification contained meaningful, demonstrable error. Commenter (2410-California Office of the Attorney General et al.) suggests that the third-party notifier be given 10 calendar days to respond, and that EPA’s determination be issued 10 calendar days after that.

Response II-14-163: EPA acknowledges the commenters’ input, EPA has expanded and explained the conditions for why a third party may be de-certified in Section X.C.2 and XI.C.2 of the preamble of the rule.

Comment: Commenter (2399-GPA Midstream Association) recommends that the effective date for implementing any program be deferred until EPA completes the process of approving notifiers and defining and approving appropriate technologies. EPA should defer any program

until it has developed robust governing requirements in a supplemental rulemaking that allows the public a full opportunity to comment on those requirements. At a minimum, any final rule should state that only observations/ identifications made no sooner than 180 days after the rule is final would be subject to the new requirements in the program. Commenter (2399-GPA Midstream Association) suggests a minimum of 180-days to provide EPA with necessary time to review and approve certified third-party notifiers and to approve qualified technologies.

Response II-14-164: The final rule has a natural delay for the implementation of the Super Emitter Program. With the new requirement that technology being used in the Super Emitter Program being approved for use through the alternative test method for methane detection technology under §60.5398b(d), which could take up to 270 days after the effective date of the rule. EPA could not consider candidate third-party notifier request until those have been received and approved and it is expected it may take a few months to process the initial third-party requests for certification.

Comment: Commenter (2626-Kayros) notes there is a large and growing body of independent, peer-reviewed research on the methodologies and technical capabilities of remote sensing technologies. The EPA can rely on existing studies, including field tests conducted by Stanford University of the detection and quantification performance of different platforms, to make an informed assessment. The large body of existing research should allow the EPA to decide in a timely manner on the list of approved third-party notifiers.

Response II-14-165: EPA agrees that peer-reviewed research on the methodologies and technical capabilities of remote sensing technologies is valuable information that could be used to aid in EPA's assessment of these technologies, however EPA cannot delegate the approval of these technologies to outside entities.

Comment: Commenter (2626-Kayros) asks EPA to select third-party notifiers based not only on their technical expertise but also on their ability to make their super emitter data publicly available and provide incentives to third-party notifiers.

Response II-14-166: EPA acknowledges the commenters' input.

Comment: Commenters (2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API) state EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control.

Commenter (2428-API) appreciates the demonstration for third party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).
- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.
- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third-party's participation in the program. Regarding EPA's proposed revocation of third-party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third-party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third-party shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

Commenter (2403-The Petroleum Alliance of Oklahoma) requests the requirements for third-party notifiers should be as stringent and equivalent to the criteria required of owners/operators submitting data to state or federal regulators to demonstrate compliance with applicable standards, e.g., results/data certified by a professional engineer or appropriate in-house professional.

Response II-14-167: EPA acknowledges the commenters' input, as detailed in Section X.C.2 and XI.C.3, EPA has revised the criteria that third-party candidates must meet to receive certification to submit Super Emitter Data.

Comment: Commenter (2399-GPA Midstream Association) argues any program should provide the specific criteria for considering whether a third-party has the true "expertise" and qualifies for this role – and allow a notice and comment process to provide stakeholders the opportunity to comment on proposed third-party notifiers. That would be consistent with how EPA accepts applications, vets and allows for public input on proposed members of boards or for peer review. Further, the commenter (2399-GPA Midstream Association) urges EPA to be fully transparent about the criteria it is considering and allow for public comment before finalizing any criteria. Only by being fully open and public about the approval criteria, would the program have any potential credibility.

Commenter (2399-GPA Midstream Association) states that one criterion that EPA should adopt is that any third-party notifier must be employed by or directly contracted to, the company that makes or operates the monitoring technology that the notifier would use to monitor emissions. A strong affiliation with the manufacturer is necessary as few people outside of the company will understand accurately and fully how to use the highly specialized equipment that EPA is contemplating (e.g., satellite imaging) or interpret their results. Although a person may be provided with basic training by the manufacturer, this is not true "expertise" in the technology and how detected data is translated into emissions data. Such expertise only comes with

extensive experience and a real understanding of how the detection technology works, which would often involve an understanding of proprietary “black box” computational and analytical methods not available to the public. As such, EPA should specify that third party notifiers will not include individuals merely reviewing publicly available online data from outside sources (like Carbon Mapper or Climate Tracer) that then notify operators based on their observation of Carbon Mapper information.

As an alternative absolute minimum, the commenter (2399-GPA Midstream Association) provides that EPA should require notifiers who meet other criteria to be certified in a specialized training program provided by the manufacturer of the technology, with demonstrated time in the field utilizing the technology overseen by a company expert to develop sufficient expertise to reliably measure and attribute relevant data. That is what EPA requires for other forms of testing and monitoring, and at a minimum, we urge EPA to be consistent and apply the same approach here.

Moreover, commenter (2399-GPA Midstream Association) urges EPA to consider how unfair it would be for EPA to retain broad discretion to approve private parties, who would be granted extraordinary powers to require other private actors to take action and potentially expose other private parties to enforcement actions or negative public perception, without providing strict and transparent qualifications. It is particularly unfair given the stringent training requirements EPA imposes on industry personnel and their contractors on a wide range of matters – and in this area, the stringent standards EPA has imposed on the senior OGI camera operators that regulated parties must use.

Response II-14-168: EPA acknowledges the commenters’ input, as detailed in Section X.C.2 and XI.C.3, EPA has revised the criteria that third-party candidates must meet to receive certification to submit Super Emitter Data.

Comment: Commenter (2258-MS) argues third parties approved to conduct monitoring should be required to obtain approval from the applicable state before being allowed to operate. While U.S. EPA has oversight, the states have the primary enforcement role, and it is inappropriate for the Agency to approve an entity to interject itself into the state’s regulatory program without the state’s approval. The proposed criteria for how U.S. EPA will certify third party entities lacks transparency and specific details. Appropriate experience and expertise must be demonstrated more fully and should be commensurate with the requirements proposed for industry personnel. Additionally, the regulated community should have access to technical data on the proposed monitoring technology from the specific monitoring entity along with approved protocols and procedures from that entity.

Commenter (2393-OSEE) states both NSPS OOOOb and EG OOOOc have language regarding the certification needed by the third-party in the notification of a super-emitter event, with each requiring in its certification to cite to its own provisions (i.e., 40 CFR 60.5371b(a) or 40 CFR 60.5388c(a)). It is unlikely that the third-party notifier will have sufficient information on the facility they are submitting to determine which regulation they are reporting under. This reinforces the assertion that, if EPA finalizes the super-emitter program, states or EPA should be

running the program since they are best able to determine if a facility is subject to the requirements of OOOOb and OOOOc.

Response II-14-169: EPA acknowledges the commenters' input, with the restructure of the Super Emitter Rule as primarily as compliance assurance program for the applicable NSPS program and for that reason it is important to maintain the third-party certification as a national program.

Comment: Commenters (2237-Industrial Commission of North Dakota, 2288-NDDEQ, 2366-BHE, 2410-California Office of the Attorney General et al., 2483-INGAA) ask will EPA set forth guidelines on what counts as "technical expertise"? To properly evaluate the proposed rulemaking, EPA needs to define the requirements for how a party will get approved as a "qualified notifier" or include the process and standards in the associated test methods. Otherwise, it is unclear what would make a person qualified and what would constitute a demonstration of technical expertise. Due to the constantly evolving nature of emissions monitoring, it would be unduly burdensome to ask every delegated authority to have an in-depth understanding for the purposes of ascertaining a third-party's technical expertise on the matter. There may be a third-party using emerging technology that has established itself in other locales but that lacks the "technical expertise" when operating in North Dakota conditions for a fair evaluation to be made.

Commenter (2483-INGAA) requests guidance from EPA, including the requirements for who will get approved as a "qualified notifier". Otherwise, it is unclear what would make a person qualified and what would constitute a demonstration of technical expertise. Commenter (2483-INGAA) considers the proposal completely arbitrary and who would qualify could vary among jurisdictions as written.

Response II-14-170: EPA acknowledges the commenters' input, as detailed in Section X.C.2 and XI.C.2, EPA has revised the criteria that third-party candidates must meet to receive certification to submit Super Emitter Data.

Comment: Commenter (2366-BHE) states as a comparison, proposed Appendix K for use of OGI technology for methane leak detection for LDAR programs includes very thorough requirements for initial operator training and certification, as well as ongoing (e.g., annual) auditing and re-certification. This includes side by side testing with a qualified expert to confirm that the OGI operator attains the same results as the expert. OGI uses infrared technology which is similar to technologies used for fence line monitoring, drones, flyovers, etc. that would be used for the SERP, but that program adds the much more difficult (and unproven) ability to not only detect a methane leak but also quantify the emission rate. Quantification has proven to be a technological challenge, and additional and more thorough methodological requirements are warranted. However, no such methods are currently in place. The very different method requirements for these two methane sensing aspects of Subparts OOOOb and OOOOc must be reconciled, and similar efficacy should be achieved for both LDAR program leak detection and SERP leak measurement.

As a comparison, commenter (2483-INGAA) notes proposed Appendix K for use of OGI technology for methane LDAR programs includes thorough requirements for initial operator training and certification, as well as ongoing (e.g., annual) auditing and re-certification.<sup>164</sup> This includes side-by-side testing with a qualified expert to confirm that the OGI operator attains the same results as the expert.<sup>165</sup> OGI uses infrared technology that is similar to technologies that would be used for the Super-Emitter Response Program, but the Super-Emitter Response Program adds the much more difficult (and unproven) ability to not only detect a methane leak but also measure the emission rate. By adding quantification of the emission rate, additional and more thorough methodological requirements are warranted, yet no such methods are proposed. The very different method requirements for these two methane-sensing aspects of NSPS OOOOb and EG OOOOc must be reconciled, and similar efficacy should be achieved for both Appendix K LDAR program leak detection and leak measurement under the Super-Emitter Response Program.

Response II-14-171: EPA recognizes the commenters' input; EPA does not consider OGI as a suitable technology for use in the Super Emitter Program as the current iteration of the technology does not meet the intent to use remote sensing in the rule in it is not quantifiable and it would require access to be conducted effectively. As technology improves and the ability to operate these cameras at a safe distance to quantify emissions, we could consider it for use in this program.

Comment: Commenter (2345-GHGSat Inc.) agrees with the EPA that any third party interested in identifying and notifying operators of super emitter emissions events must be pre-approved by the Agency for the notification to be valid. Commenter (2345-GHGSat Inc.) also agrees with EPA's intention of vetting any interested third-party notifier (e.g., technology vendor, researchers, non-profit organization, other parties) through defined approval criteria. Commenter (2345-GHGSat Inc.) believes these criteria should be based, at least in part, on the proposed pre-screening and evaluation tenets suggested for the alternative test method for advanced methane detection technologies. An effective emissions detection system needs to simultaneously satisfy the following requirements:

1. Well-characterized detection limit based on a POD curve.
2. Well-characterized, high specificity (low rate of false positives).
3. Well- characterized quantification accuracy.

Therefore, commenter (2345-GHGSat Inc.) recommends that the EPA incorporates these three requirements as part of the registration criteria. Commenter (2345-GHGSat Inc.) believes that the following questions, which are based on the proposed vetting for alternative test method, should be part of the criteria:

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<sup>164</sup> Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging (hereinafter Proposed Appendix K) § 10.0 (Camera Operator Training).

<sup>165</sup> Appendix K, § 10.2.2.2.

1. The desired applicability of the technology (i.e., site-specific, basin-specific or broadly applicable across the sector). In the case of the commenter (2345-GHGSat Inc.), the company currently operates two different platforms (satellite and aircraft) that can provide both site and basin specific.
2. A description of the measurement system. Commenter (2345-GHGSat Inc.) believes this question needs to be coupled with scientific explanations and proper vetting from the scientific community. Nonetheless, this description should protect any intellectual property associated with the technology in consideration. The EPA should provide a mechanism to safekeep any information that is marked confidential and/or that obeys any intellectual property clauses.
3. Supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field. Commenter (2345-GHGSat Inc.) acknowledges that there is a need for standardized methods for evaluating the performance of the alternative technology systems. Commenter (2345-GHGSat Inc.) believes that measuring systems must be validated using the statistical metrics of sensitivity, specificity, and quantification accuracy. Hence, commenter (2345-GHGSat Inc.) believes this is a critical question that needs to be further expanded to cover the statistical metrics mentioned herein. A full discussion of these three metrics and its applicability to the satellite platform is provided by (McKeever, et al., 2022).
  - a. Sensitivity
    - i. In detection systems, sensitivity describes how effective the system is at detecting an emission that is indeed present. The is also known as the rate of true positives. Understanding this rate allows defining the concept of detection limit, in which the sensitivity of a system increases for higher (true) emissions rates and approaches zero for very low rates.
  - b. Specificity
    - i. The metric of specificity describes how good a system is in minimizing the number of erroneously declared detections when in fact no emission was present. These events are known as false positives, whose occurrences only create additional work and emissions mitigation. Hence, a measurement system with low or no false positives instances is said to have high specificity.
  - c. Quantification
    - i. The metric of quantification is determining the mass emission rate of an event. This proposed rule places an important emphasis on this metric, as it is proposed as the qualifying metric under the matrix system. Commenter (2345-GHGSat Inc.) believes that quantification accuracy must be measured and specified along with the corresponding measurement uncertainties. Reporting these two values supports the credibility and validity of the measuring system.
    - ii. It is important to note that the quantification metric, along with the sensitivity metric, is related to the detection threshold, which in turn, relates to the POD.



- d. Detection Threshold
  - i. A system's detection threshold can be described utilizing a POD curve, which relates the system's sensitivity, specificity, and quantification by determining the smallest emission that could be detected and the corresponding probability of actually detecting it. Currently, the creation of a POD curve could rely on simulation or in practical trials with controlled releases.
  - ii. Measuring systems need to deal with uncontrolled environmental variables. In the case of remote sensing measuring systems, environmental variables like terrain reflectance, atmospheric turbulence, and wind conditions directly impact the detection threshold. The wind speed has a strong influence on the detection probability, hence, commenter (2345-GHGSat Inc.) requests that EPA establishes a requirement for POD to be expressed as a function of wind speed. For example, the detection threshold of the commenter's (2345-GHGSat Inc.) systems is expressed using a reference wind speed of 3 meters per second. In the commenter's (2345-GHGSat Inc.) platforms, the POD curve does not behave as a step-function, rather, there is a smooth increase in detection probability as the emission rate increases. In this curve, it is observed that the emission rates at 50% and 90% POD are close in magnitude. Commenter (2345-GHGSat Inc.), in agreement with best practices documented in the scientific literature, reports its detection threshold based on a POD at 50% and using a reference wind speed of 3 meters per second.
- 4. A detailed description of the alternative testing procedure(s), including data quality objectives to ensure the detection threshold(s) are maintained and procedures for a daily verification check of the measurement sensitivity under field conditions. Commenter (2345-GHGSat Inc.) believes that this requirement is important. This requirement is intrinsically linked to requirement 3. The concepts explained by commenter (2345-GHGSat Inc.) in the commentary for requirement 3 are applicable here. It is important to note that field conditions vary through the United States, making it more challenging to provide a general detection threshold at 90% POD. For this reason, Commenter (2345-GHGSat Inc.) recommends utilizing 50% POD instead, in a way to accommodate for varying conditions.
- 5. Standard operating procedures consistent with the EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control. Commenter (2345-GHGSat Inc.) agrees that Standard Operating Procedures (SOPs) will need to be set in place by technology providers. However, these SOPs should follow a common template to allow for inter comparability between technologies. Therefore, commenter (2345-GHGSat Inc.) recommends the EPA to create such template.

Response II-14-172: EPA acknowledges the commenters' input, as detailed in Section X.C.2 and XI.C.2, EPA has revised the criteria that third-party candidates must meet to receive certification to submit Super Emitter Data.

Comment: Commenter (2157-Division of Air Pollution Control Tennessee Department of Environment & Conservation) notes EPA’s proposed grant of such authority to nongovernment entities potentially violates the Private Nondelegation Doctrine, which generally prohibits the delegation of public powers to private entities.<sup>166</sup> Although EPA states that the “qualified third-party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications . . . [which] would not represent the initiation of an enforcement action by the EPA or a delegated authority”, EPA would, in fact, be granting these private actors significant investigatory powers, which would otherwise be performed by agency personnel. Proposed § 60.5388c specifically compels affected facilities to respond to super emitter emissions events by conducting root causes analyses, then taking appropriate corrective action and reporting investigation findings to EPA. Therefore, these private third parties would, in fact, step into the shoes of a regulator because they could compel facilities to conduct these activities under the color of law.

Response II-14-173: EPA has revised the final rule to include EPA in a centralized role to approve technology, certify third parties, receive reports from the third parties, and review the data for accuracy and reasonableness before notifying an owner or operator. In the final rule, a certified third party has no authority other their ability to submit legally obtained super emitter data to the EPA.

Comment: Commenter (2177-Ute Indian Tribe, 2366-BHE, 2483-INGAA) asks for further clarification/definition of what specifically comprises a "third-party"? Commenter (2177-Ute Indian Tribe) recommends that a third-party be defined such that a group/organization will get approved as an approved notifier, but each individual within the group/organization that will be conducting any OGI camera surveys be qualified as a certified camera operator. Any petitions to remove a third-party from the approved list should be to remove a group/organization, not an individual.

Response II-14-174: EPA recognizes the commenters’ input; EPA does not consider OGI as a suitable technology for use in the Super Emitter Program as the current iteration of the technology does not meet the intent to use remote sensing in the rule in it is not quantifiable and it would require access to be conducted effectively.

Comment: Commenter (2177-Ute Indian Tribe) responds to EPA’s solicitation for comment on the following proposed text:

“Qualifications for notification. If, in the Administrator’s judgement, a third-party (i.e., someone other than the owner or operator of the site with a detected super emitter emissions event, the Administrator, or the delegated authority) demonstrates technical expertise in any of the remote detection technologies and/or methods specified in paragraphs (a)(1) through (3) of this section the third-party would use, the Administrator will approve that third-party as a qualified notifier that is eligible to submit a notification

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<sup>166</sup> See generally, *Nat'l Horsemen's Benevolent & Protective Ass'n v. Black*, 53 F.4th 869, 880 (5th Cir. 2022) (“Our Constitution permits only the federal government to exercise federal power.”).

of a super emitter emissions event to an owner or operator as specified in paragraph (b) of this section.”

Commenter (2177-Ute Indian Tribe) states third parties should not be allowed as qualified notifiers. The commenter recommends deleting this requirement. If this requirement is kept, third parties should be required to meet the requirements in Appendix K, section 10.0 for camera operator training.

Response II-14-175: EPA acknowledges the commenters’ input.

Comment: Commenter (2301-U.S. Chamber of Commerce) argues notifiers should also be required to certify that they have no conflicts of interest (e.g., employment by competitor companies) and made subject to periodic recertification. These additional requirements will help reduce the risk that individuals without proper training or experience inaccurately record or report information or accidentally report information to the wrong owner or operator based on confusion about the ownership of a facility or the source of the alleged emission event.

Commenter (2410-California Office of the Attorney General et al.) requests that EPA provide more detail on the revocation procedure, to ensure that third-party notifiers are not denied the right to participate in the program without sufficient evidence, and to ensure that such a revocation procedure does not chill third-party participation in the program.

Commenter (2247-Ohio Environmental Protection Agency) notes it appears that U.S. EPA will be required to approve all super emitter notifiers. A lot of individuals will likely want to be approved as a qualified super emitter notifier. Has U.S. EPA tried to estimate how many Ohio EPA Comments on U.S. EPA’s December 6, 2022, Proposed Rules Regulating the Oil & Gas Industry Page 4 will ask to be approved as a notifier and does U.S. EPA have the staffing to review these in a timely basis? Will the public be notified of this official approval? Will U.S. EPA require approved notifiers to conform to a set of operating parameters?

Response II-14-176: EPA acknowledges the commenters’ input, as detailed in Section X.C.2 and XI.C.2, EPA has revised and expanded the criteria that third-party candidates must meet to receive certification to submit Super Emitter Data. EPA has placed the revocation process into the third party process not to chill participation but to ensure the accuracy and reasonableness of the data being submitted by these third parties, as data quality of the submittals is foundation to a successful program.

Comment: Commenter (2247-Ohio Environmental Protection Agency) asks has U.S. EPA considered having the delegated authorities approve notifiers? Would this be part of the approval process of the 111(d) plan?

Response II-14-177: EPA acknowledges the commenters’ input, with the restructure of the Super Emitter Rule as primarily as compliance assurance program for the applicable NSPS program and for that reason it is important to maintain the third-party certification as a national program.

#### ***14.5.5 Notification Timeline***

Comment: Commenter (2458-MiQ) supports the proposed notification timelines in the SERP. The commenter supports the Corrective Action (IV.C.2) provision and timeframe. It will provide the operator with enough time to prioritize a causal examination.

Response II-14-178: EPA acknowledges the commenters' support for the Super Emitter Program.

Comment: Commenters (2218-TCEQ, 2626-Kayrros) state the amount of time required for notifications following the detection of a super emitter will depend on the type of remote sensing technology, the ability to identify the relevant operator and the capabilities of the third-party notifier. The latency of detection and quantification may vary across different platforms, but the EPA could require that notification be sent within a fixed time period. In the case of satellite monitoring, the pre-processing and quality control performed by the satellite operator creates a time lag of up to two days, while the analysis can be completed in a matter of hours.

Response II-14-179: EPA acknowledges the commenters' input; EPA has detailed the timelines and the rationale for them in Section X.C.2 and XI.C.3 of the preamble of the rule. EPA is requiring that third-party reports be submitted within 15 days of detection regardless of technology used.

Comment: Commenters (2177-Ute Indian Tribe, 2213-Oxy, 2220-WDEQ, 2237-Industrial Commission of North Dakota, 2248-NDPC, 2288-NDDEQ, 2305-The Williams Companies, Inc., 2389-ACC, 2428-API) are concerned about the significant lag time between when an emission event is detected to when it is ultimately reported. This prevents the third-party from submitting multiple notifications at one time and creating a workload for the operator that is unreasonable. Commenters (2237-Industrial Commission of North Dakota, 2288-NDDEQ, 2428-API) state technologies such as satellites or aerial methods, due to the large amount of data and the QA/QC processes required to identify both emissions meeting the 100 kg/hr threshold and the exact location where the emissions are coming from, can take weeks if not longer to complete. This delay lessens the actual effectiveness in the confirmation and identification of super emitter events. Furthermore, the Leak Detection and Repair requirements result in ongoing repairs of leaks as they occur and are found. Given the potential time delay for the super emitter program, the inability to confirm and identify the information may lead to confusion or mistrust in the system and agency. Commenter (2288-NDDEQ) has already had a situation where a third-party monitoring company reported detection of a large methane release at a facility, however this information was not received until a month after the detection. In the commenter's investigation of the matter, the release appears to be at least partly related to a NSPS OOOOa component that had already been detected by the facility and was on delay of repair at the time of the third-party detection.

Commenter (2220-WDEQ) understands that it can take weeks for data from remote detection methods to be processed. As a result, it is possible that data could indicate a compliance event that occurred in the past due to an issue that was not replicable and potentially already corrected

by an operator with involvement of WDEQ's Compliance program staff. Based on the proposed SERP, operators would have to expend significant time and resources undertaking root-cause analyses for one-time-event compliance issues that may have already been resolved.

Commenters (2258-MSA, 2301-U.S. Chamber of Commerce, 2389-ACC, 2399-GPA Midstream Association) note proposed § 60.5371b(b)(7) only requires a third-party to notify the owner or operator of the site "as soon as practicable." EPA does not define what is "practicable." This is a significant concern as the ability to verify any large emission event and, if verified, the cause of the event, will diminish greatly with time. Delays in receiving notice would therefore frustrate the owner or operator's investigation. It makes no sense to allow notifiers a flexible, and potentially long, timeline for submitting their notices and then require operators to respond on a tight, rigid timeline with no consideration of practicability.

Additionally, commenter (2305-The Williams Companies, Inc.) states the proposed program places no obligation upon the third-party to provide timely data (e.g. within 5 days of detection), to understand the source in question, to take measurements with the same objectivity expected of a regulatory agency or independent consultant, or to demonstrate an on-going proficiency in the technology or training in the use of the equipment as is expected of governmental agencies and regulated entities.

Response II-14-180: EPA is requiring that third-party reports be submitted within 15 days of detection regardless of technology used in the final rule. EPA considers it important to provide owner or operators with timely information as it aids in their investigation into the potential cause(s).

Comment: Commenter (2345-GHGSat Inc.) understands that the EPA wants to have a notion as to the time it takes from detection to notification. The commenter wants to convey that there are multiple factors affecting the gap in time between these two events. One important factor is the type of platform making the detection. For the satellite platform for example, the data captured by each satellite needs to be downloaded when the satellite is nearby the procured download link on earth. This process can occur within a few hours of taking the measurement to up to 24 hours. Then, there is an initial processing time in which each detection goes through a queue. This can also take a few hours to up to 24 hours. At this point the presence of an emission is identified, moving this imagery to further processing for assessment and quantification of emission rate and uncertainty. This can also take a few hours to up to 24 hours. Therefore, the notification deadline should be no sooner than 4-5 days, which includes an additional 24-48 hours to cover any eventuality.

Commenter (2345-GHGSat Inc.) states in the case of the aircraft platform, the data gathering is different than the satellite, since this platform sweeps an entire area, collecting multiple terabytes of information. The initial processing of the vast amount of data typically takes 24-48 hours, in which imagery gets identified for further assessment and quantification. That process can take a few hours to up to 24 hours. Similarly, to the satellite platform, the notification deadline should be no sooner than 4-5 days, which includes an additional 24-48 hours to cover any eventuality.

Response II-14-181: EPA acknowledges the commenters' input and while we are encouraged at the timeline that some technology vendors need to process data, we wanted to provide sufficient time for the third parties to review this data and to confirm the owner or operators of these sites so in the rule we are requiring third party reports must be submitted within 15 days.

Comment: Commenters (2345-GHGSat Inc., 2348-Energy Workforce and Technology Council) believe one way of ensuring that an outreach gets to a company representative is that each operator designates an email address specifically for the SERP. That way, the response time should be minimized, and the operator is in control of that response time.

Response II-14-182: EPA is requiring that third-party reports be submitted within 15 days of detection regardless of technology used in the final rule.

Comment: Commenter (2348-Energy Workforce and Technology Council) indicates that if an emission event is validated by qualified personnel and technology, then the notifier should be required to report the emission to the operator within a 1-day of discovery and validation. This is possible where a continuous monitoring system is in place because such a system produces data very quickly—i.e., location, threshold, and duration are reported at the time of detection via email/text to the service provider and the customer/operator.

Commenter (2248-NDPC) requests that the alleged findings are not made public until actual emissions are observed and documented by the operator. The EPA should make it clear that all pertinent evidence must be provided to the operator at the time of the notification by the third party. Withholding information should be considered grounds for disqualification.

Commenter (2294-Ohio Oil and Gas Association) recommends the notification must be made as soon as practicable, but no later than 3 days after the alleged super emitter event.

Commenters (2248-NDPC, 2409-BP America Inc.) argue that notification to the state agency and operator needs to be within 48 hours. Commenter (2409-BP America Inc.) continues, EPA should then promptly confirm receipt of the data and notify all operators potentially implicated by the super emitter event, including any such operators that did not receive notice directly from the third-party. Providing notification of the alleged leak weeks or months after the finding could make it difficult or impossible to identify the source of the emissions. Late notifications are a burden on the state agency's resources as well as the Operator's.

Commenters (2301-U.S. Chamber of Commerce, 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2409-BP America Inc.) argue EPA should require third parties report an event to the EPA and/or state delegated agency for review no later than 5 calendar days after the event. EPA and/or the state delegated agency would then notify the operator to verify a release and take corrective action, if needed. Only an event that has been verified and corrective action taken would be made available to the public on EPA's or the state delegated agency's existing website.

If the operator and or facility is known to Commenter (2345-GHGSat Inc.), immediate notification occurs through GHGSat’s SPECTRA platform and via email. When the operator is unknown or the location is not clearly attributed to an operator (e.g., subsurface infrastructure), a discovery phase is required to uncover these details. Based on this, the suggested additional time should be no less than 5 to 6 days.

Commenter (2258-MSC) states that the proposal that notification be given “as soon as practicable” is not adequate. According to commenter (2258-MSC), recent experience has shown that delays greatly hamper the ability of a source to investigate and respond to the notice, and notice should be required within 7 business days of the alleged event.

Commenter (2282-Kinder Morgan Inc.) argues if EPA moves forward with the super emitter proposal, it must also provide an exception to any proposed timeframe, for good cause shown. Although EPA appears to allow for some flexibility in timeframe for completing a corrective action by allowing development of a corrective action plan if the cause analysis and corrective action cannot be completed in 10 days, additional flexibility is required. The proposal does not provide for any exceptions for the time required to develop a corrective action plan. The commenter understands EPA’s motivation for a rapid response, but EPA should nevertheless provide exceptions, for good cause shown to the specified timeframes.

Response II-14-183: EPA acknowledges the commenters’ input; EPA has detailed the timelines and the rationale for them in Section X.C.2 and XI.C.3 of the preamble of the rule. EPA is requiring that third-party reports be submitted within 15 days of detection regardless of technology used.

Comment: Commenter (2247-Ohio Environmental Protection Agency) asks if a super-emitting event is identified, and it is not yet safe to attempt a repair, how does the owner/operator get approval to delay the initial repair past the 10 days?

Commenter (2345-GHGSat Inc.) believes the EPA should consider implementing deadlines for first and final attempts for repairing and verifying the leak based on the severity (mass emission rate), regardless of the component type or infrastructure.

Response II-14-184: EPA has revised the final rule to attach the repair timeline to the applicable regulation for the source of the super-emitter event, if the applicable regulation includes an allowance for delay of repair, then an owner or operator must be subject to those standards.

Comment: Commenter (2222-Wisconsin Department of Natural Resources) notes that EPA solicits comment on the amount of time allowed for notifications to sources following detection of a super emitter emissions event. Commenter (2222-Wisconsin Department of Natural Resources) suggests that absent an approved method or direction on super emitter identification, EPA should work with states and tribes on establishing a super emitter program including identification and communication.

Response II-14-185: EPA acknowledges the commenters’ input.

#### **14.5.6 Required Notification Information**

Comment: Commenters (2202-TXOGA, 2348-Energy Workforce and Technology Council, 2403-The Petroleum Alliance of Oklahoma, 2453-Carbon Mapper and RMI) state notifiers should be required to provide proof of data of the event (time, date, location, visual evidence of leak origin), per the specifics of the equipment used to detect the event. Precise timing information can help minimize the chance of false alarms and aid in follow-up analysis by operators. The standards are accreditation of such notifiers would need to be put into place, as none exists today, and should be a government certified activity. These third-party notifiers must also have authorization to be on private, tribal, and federal land, as well as clearance of OSHA or industry required training if on neighboring well or production site.

Response II-14-186: EPA acknowledges the commenters' input; EPA has detailed the criteria for third parties in Section X.C.2 and XI.C.2 of the preamble of the rule. The rule also includes a provision that if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification would be revoked.

Comment: Commenter (2428-API) states at least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored.
- Description of monitoring equipment to be used to conduct the activity.
- Documentation of emissions detection limit.
- Proposed starting date and duration of the monitoring activity.
- Contact details (*e.g.*, name, phone number, title) of third-party contact person.
- Name and details of owner of remote monitoring equipment.
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA).
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

Commenter (2428-API) adds with the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

Response II-14-187: EPA acknowledges the commenters' input; EPA has not chosen to require third parties to provide owner or operators of a notification of when they choose to conduct a survey as we consider this to be burdensome and, in some cases, technically feasible. Approved third party may choose to volunteer this information to the owner or operators.



Comment: Commenter (2389-ACC) recommends EPA ensure that its communication of any monitoring results or facility response information is rooted in principles of accurate risk characterizations and context. Throughout this process, the Agency should not only maintain its capacity and engagement to assess the monitoring results for quality and scientific accuracy, but also prioritize its ability to clearly communicate proper context and meaning of the information presented in the reports. EPA should further ensure that public communication of any monitoring information clearly states what the data means (and just as importantly, what it does not mean) and how it should be used. If EPA retains public dissemination of the reports, it is critical for the Agency to communicate the meaning and proper usage of the emissions data to help communities fully understand it. Without this information and context, these programs may result in widespread misinformation and unnecessary alarm, which only serves to defeat the Agency's overall goal to improve public understanding around these events.

Response II-14-188: EPA acknowledges the commenters' input; In the final rule, the EPA has finalized the Super-emitter program is being developed with transparency in mind, on the part of the third-party, the EPA, and the owner or operator. All notifications meeting the requirement in the final rule will be published online on the EPA's Super Emitter Portal - <http://www.epa.gov/super-emitter>.

Comment: Commenter (2458-MiQ) states EPA should provide clear data quality parameters in advance, and these should be updated on an annual basis. This will provide guidance in advance of any third-party notification of a super-emitter event about the type and quality of data that must be submitted. To ensure that the SERP functions as intended, EPA should conduct post-notification audits to ensure compliance with the notification data quality guidelines.

Response II-14-189: EPA has revised the criteria for third party notifiers in the Super Emitter Program as detailed in Section X.C.2 and XI.C.2 of the preamble of the rule detailing requirements for developing a data evaluation program, likewise the Super Emitter Program to use methane detection technology approved. The rule also includes a provision that if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification would be revoked.

Comment: Commenter (2403-The Petroleum Alliance of Oklahoma) notes the Proposed Rule does not discuss what will be included in the report that will be placed on the website or how this information will be provided in easy, understandable format. Any monitoring data should be fully transparent *e.g.*, identify who collected it, how it was collected, when it was collected, what technology was used, accuracy information, and other pertinent information. EPA should require third-party notices of an event be sent to EPA and/or the state delegated agency first. EPA and/or the state delegated agency would review this information and contact the operator to verify the event and take corrective action, if needed. Only after the event is verified and corrected should the event information, be made available to the public on EPA's or the state delegated agency's website.

Commenter (2403-The Petroleum Alliance of Oklahoma) adds the Proposed Rule does not provide any details of the technologies that will be used by third parties (other than general

information i.e., remote sensing aircraft, mobile monitoring platforms or satellites), whether these same technologies are allowed to be used by operators instead of OGI, the associated level of accuracy, reliability, and sensitivity of the technology, nor the quality or accuracy (errors and false positives) of data generated by the technology.

Commenter (2403-The Petroleum Alliance of Oklahoma) argues EPA super-emitter program should make available to the public the type of technology being used, the accuracy, reliability, and sensitivity of the technology, and the quality or accuracy (errors and false positives) of data generated by the technology for each event on its website. EPA should allow the public the opportunity to review and comment on the technology before being approved for use by a third party. Also, any technology used by third parties should be allowed to be used by operators in lieu of OGI.

Response II-14-190: Any methane detection technology used as part of the program must be approved for use through the advanced methane detection technology program as detailed in §60.5398b(d). Section X.B details criteria for this approval.

Comment: Commenters (2168-INOGA, 2172-Kentucky Oil and Gas Association, 2294-Ohio Oil and Gas Association) note EPA needs to require that notification provided to an owner / operator is delivered in writing. Verbal notification is insufficient when action is required. Verbal notification may be provided to the owner / operator as a courtesy but is insufficient as proof that notification has been served. The written notification should provide sufficient details about the incident for the owner / operator to act and not question the validity of the notification. The minimum information that should be included in the notification includes date that the deficiency was observed, name of the entity making the observance, flow rate, equipment used, last calibration date for equipment, and latitude and longitude.

Response II-14-191: EPA acknowledges the commenters' input; the final rule has been structured to require all notifications will come from the agency to the owner or operator. It is intended these notifications will be provided to an owner's or operator's responsible official.

Comment: Commenter (2433-EDF et al.) also notes that EPA inherently retains control over the entire program. If certain notifiers are repeatedly submitting data that do not include all six of the elements proposed by EPA, that data would simply not require the operator to take action. Independent parties with the technical expertise necessary to collect this type of data and meeting EPA's certification requirements should not face decertification for minor technical errors in submissions.

Response II-14-192: EPA has revised the criteria for the certification and decertification of the third-party notifiers in the Super Emitter Program as detailed in Section X.C.2 and XI.C.2 of the preamble of the rule. It is not the intent of the agency to decertify notifiers for minor errors in submissions, however if errors are persistent and they effect either the identification of an owner or operator or the misidentification of a super emitter event, that could result in a decertification.

Comment: Commenter (2409-BP America Inc.) suggests that EPA revise the program to require that, within 5 days of notification from either a third-party or EPA, operators should perform an initial evaluation of the data and make best efforts to confirm whether the event occurred at its site, and if so, whether the emissions were (a) caused by an anticipated, short duration event such as operations and maintenance activity at the site; or (b) unplanned / fugitive emissions. EPA could then structure the program along the following lines:

- If the operator's initial evaluation of the data indicates that a super emitter event has not occurred at the operator's site, the operator could document this finding and report it to the EPA (or state with delegated authority). The operator's obligations under the SERP program would be complete.
- If the operator's initial evaluation indicates that the event was caused by a scheduled intermittent event from O&M activity, the operator could similarly be required to document this finding and report it to EPA (or the state). Again, the operator's obligations under the SERP program would be complete.
- If the initial evaluation of the data indicates that (a) the emissions were unplanned and (b) leak repair or other corrective action is required under EPA's regulations, the operator could then be required to determine and execute the appropriate corrective action, document the actions taken, and notify EPA (or the state) within the time frame set by regulation. If the operator deems that it is not feasible to act within that timeframe, the operator may be allowed to document the reasons for incomplete action and notify EPA (or the state) that more time is needed.

Commenter (2409-BP America Inc.) adds key to these suggestions is that communications and decisions take place between the operator and the regulatory authority, not with the third-party, and that there are clear off ramps and incentives provided for operators who can promptly evaluate data and take action, if needed.

Response II-14-193: As detailed in section X.C.2 and X.C.4 of the preamble of the rule, EPA has revised the Super Emitter Program to identify what investigations are required by the owner or operator and are consistent with the input provided by the commenter.

Comment: Commenter (2409-BP America Inc.) argues EPA must go further and provide more specificity with regard to the validation process. At a minimum, EPA should ensure that approved third parties are familiar with GIS systems; demonstrate experience implementing methane measurement campaigns; and have the ability to process methane data in a timely and transparent manner.<sup>167</sup>

Response II-14-194: EPA acknowledges the commenter's input; EPA has included specific criteria in the certification process that a third party have expertise in the technology used and to

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<sup>167</sup> Because super emitter events are based on an emissions rate (i.e., of 100kg/hr or greater), there is an even greater need for third parties to transparently process and disclose their data given the uncertainties inherent in emissions rate estimation.

develop data evaluation procedures to ensure the data submitted is accurate and reasonable. These criteria are detailed in section X.C.2 of the preamble of the rule.

#### ***14.5.7 Abuse of Third-party Reporting Privileges***

Comment: Commenters (2202-TXOGA, 2220-WDEQ, 2227-Western Energy Alliance, 2240-Rose Rock Environmental Services, LLC, 2254-PBPA, 2282-Kinder Morgan Inc., 2258-MSA, 2283-Endeavor Energy Resources, 2284-Kairos Aerospace, 2301-U.S. Chamber of Commerce, 2346-Encino Environmental Services, LLC, 2389-ACC, 2399-GPA Midstream Association, 2446-IPAA, 2483-INGAA, 2626-Kayros, 2713-Northeast Natural Energy LLC) argue the delegation of authority would require much more careful quality control with much better oversight than that articulated in the proposed rules. The opportunity for false identification of source and operator and poor-quality data would render the program highly problematic. Commenter (2713-Northeast Natural Energy LLC) notes although EPA must approve the third-party and screening methodology, the confidence in the algorithms that such technologies use to determine emission rate has a low confidence level within industry. EPA must use an extremely strict protocol to determine if the proposed method used to determine emission rate is close to 100% accurate.

Response II-14-195: EPA acknowledges the commenters' input; the final rule has been revised to require any methane detection technology in the Super Emitter Program to be approved for use using the same criteria used for the advanced methane detection technology program as described in §60.5398b(d). It is important that the technology used is appropriate for use in the Super Emitter Program and will be operated in such a manner that will ensure only high-quality data will be submitted to the EPA.

Comment: Commenter (2391-CEC) encourages EPA to consider how to limit the potential for abuse of this program. According to the commenter (2391-CEC), operators such as CEC are already devoting enormous resources to analyzing the substantial amount of data they already receive on an ongoing basis. This proposed program could be a serious drag on these resources for little or no environmental benefit if, for example, third parties submit reports and data on activities that are fully authorized or already identified and corrected.

Commenters (2227-Western Energy Alliance, 2240-Rose Rock Environmental Services, LLC, 2254-PBPA) state EPA would be delegating to groups with unverified qualifications and technical expertise, an unprecedented action. This provision of the proposed rules is also a violation of the separation of powers of the U.S. Constitution where EPA is seeking to legislate and grant legal authority to itself to delegate regulatory authority to third-party members of the public to monitor and report on regulated facilities, a legislative act that resides solely with Congress.

Commenter (2227-Western Energy Alliance) states improperly delegating regulatory monitoring to third-party members of the public who are not directly answerable for the proper implementation of rules opens the door for improper records, inaccurate reporting, inaccurate data that fails regulatory quality standards, and lack of essential oversight for program integrity.

The most obvious and likely error will be misidentifying an operator's facility. EPA should remove the program from the final rule. Should EPA seek the appropriate legal authority from Congress and proceed with such a program in the future, EPA should not post any purported super-emitter reports on its public website until EPA has properly identified the facility; confirmed the responsible operator and emissions source; verified the emissions source is large enough to fall under the super-emitter designation; quality assured the data; and confirmed the facility is subject to the rules.

Response II-14-196: EPA acknowledges the commenters' concerns. The final rule no longer includes third party acting as an "authorized representative" under 114(a)(2) and instead has EPA in a centralized role as explained in section X.C.1 and XI.C.1 in the preamble of the rule.

Comment: Additionally, commenter (2389-Amercian Chemistry Council) notes EPA does not take any review role or responsibility in the management or quality assurance of the data itself. Indeed, EPA expressly abdicates such a responsibility and states that "a greater role for the Agency in reviewing third party notifications would be an unnecessary task," instead stating that it would be duplicative of the predicate approval processes and third party revocation procedure.<sup>168</sup> It defies logic to reconcile this decision with EPA's statement in the same discussion noting that the program as proposed "retains oversight by the EPA over all key decision making elements of the program."<sup>169</sup> It seems inconsistent for EPA to deny its role to review the information it requires third parties to collect as "an unnecessary task" but simultaneously claim it retains "oversight" over "all key" program elements. The commenter (2389-Amercian Chemistry Council) strongly urges EPA to review the notification reports created by third parties prior to their public dissemination. This crucial step would allow the Agency additional time to correct any errors while providing additional context for the meaning and interpretation of the data contained in the reports.

Commenters (2202-TXOGA, 2258-MSC, 2283-Endeavor Energy Resources, 2301-U.S. Chamber of Commerce, 2360-Devon, 2403-The Petroleum Alliance of Oklahoma, 2446-IPAA) recommend that the criteria for third-party notifiers be as stringent and equivalent to the criteria required of owners/operators submitting data to state or federal regulators to demonstrate compliance with applicable standards, e.g., results/data certified by a professional engineer or appropriate in-house professional.<sup>170</sup>

Response II-14-197: EPA acknowledges the commenters' concerns; the final rule has been revised to include third parties are certified against an expanded criteria as explained in Section X.C.2 and XI.C.2. Also, any submittal must be attested by an official of the "certifying official" that the third-party notifier.

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<sup>168</sup> 87 FR 74751.

<sup>169</sup> Id.

<sup>170</sup> The results/data submitted by the third-party need to be certified by a professional engineer or another qualified individual with relevant experience. Said individual should be required to provide a certification as to the accuracy of the data that is equivalent to, if not the same as, that required of professional engineers or other qualified individuals are required in other sections of this Supplemental Proposal.

Comment: Commenters (2360-Devon, 2446-IPAA) add in order for the emission event data to be useful, it must be collected in substantially the same manner and under the same conditions that operators would be expected to adhere to and provided to the operator within three days or less of the initial detection. These emission events may often be short-lived and intermittent in nature, and time is of the essence. Notifications falling outside this timeframe will often lead to an operator seeking to confirm an event that is no longer occurring.

Response II-14-198: EPA acknowledges the input from the commenter; EPA agrees that is important for super-emitter data to come in as soon as possible upon the detection of an event, in the final rule, super emitter data must be reported within 15 days of the event. This time is sufficient time for a third party to receive and review data for accuracy to ensure the data is reasonable to submit to the EPA.

Comment: Commenter (2227-Western Energy Alliance) adds OGI cameras, especially when used by entities not familiar with the facility in question, would not be consistently able to quantify emissions. It is not uncommon for untrained parties unfamiliar with regulations and operations to erroneously report alleged violations. Questions exist as to whether EPA has the authority to assign formal compliance duties such as this to nongovernmental entities, whereas states are required to go through lengthy formal State Implementation Plan programs to be delegated authority to enforce federal regulations such as New Source Performance Standards. Surely nongovernmental entities, that lack the air quality expertise that states have demonstrated for half a century, should not be given similar authority without much more deliberative thought, consideration, and training. The entire Super-Emitter Program as proposed by EPA is arbitrary and capricious.

Commenter (2202-TXOGA) gives the example, EPA imposes a certain level of periodic training and procedural requirements for operators and equipment used in conducting M21 or OGI surveys, the results of which trigger regulatory obligations. Because notifications under this program would also trigger regulatory obligations, the notifiers should at least be held to the same (or substantially similar) standards that EPA would impose on an operator for its use of monitoring technology. These requirements should include, but not be limited to, periodic training, periodic certification of notifier technicians and monitoring equipment, quality assurance plans, and the like.

Response II-14-199: EPA acknowledges the commenters' concerns; EPA has revised the third-party certification criteria as explained in Section X.C.2 and XI.C.2 to ensure the third party is adequately trained in the remote sensing technology used for surveys.

Comment: Commenters (2168-INOGA, 2172-Kentucky Oil and Gas Association, 2202-TXOGA, 2220-WDEQ, 2258-MSA, 2283-Endeavor Energy Resources, 2305-The Williams Companies, Inc., 2345-GHGSat Inc., 2393-OSEE, 2446-IPAA, 2626-Kayrros) are concerned with EPA's leniency on reporting inaccurate/false information and removing third-party notifier's certification. Trust in the accuracy of remote-sensing data will be essential to the SERP. The approval of a third-party notifier should be revoked when repeatedly submitting false reports.

Commenters (2227-Western Energy Alliance, 2238-SOOGA, 2248-NDPC, 2294-Ohio Oil and Gas Association) are particularly concerned about the implications of “false positive” super-emitter events. The occurrence of a “false positive” can be due to several factors, including faulty equipment, insufficient and/or unreliable data, and incorrectly identifying the super-emitter source. Regardless of the cause, “false positive” super-emitter events will result in operators unnecessarily incurring significant costs, and also stigmatize the accused operator and the industry as a whole. The commenters urge U.S. EPA to implement appropriate safeguards against the occurrence of “false positive” super-emitter events.

Commenters (2399-GPA Midstream Association, 2446-IPAA) contend third-party notifiers that violate federal, state or local ordinances in the attempt to gather information/data on alleged super emitter events should have their certifications revoked for no less than a year and the particular third-party notifier and any/all affiliates should be prohibited from the ability to allege future super emitter events at the underlying source/facility. Commenter (2399-GPA Midstream Association) adds after the one-year period, the entity may re-apply to be re-approved.

Commenter (2399-GPA Midstream Association) urges EPA to incorporate a cap across an entire operator’s asset base, such as a maximum of six improper notifications per rolling 12-month period per parent company.

Commenters (2202-TXOGA, 2345-GHGSat Inc., 2626-Kayrros) state any third-party notifier that reports incorrect information (i.e., a false positive) should be revoked from the program after three incorrect notifications to protect the integrity of the entire program. Commenter (2345-GHGSat Inc.) urges the EPA to further define the concept of demonstrable error and to specify if this “strike system” has a defined timeline (e.g., a limit of three errors per calendar year).

Commenters (2258-MSA, 2305-The Williams Companies, Inc.) argue the three-time threshold for inaccurate event notifications from a third-party is too high and limited to multiple notifications at the same facility owned by the same operator. This creates the potential for a third-party to submit demonstrably inaccurate information for many different facilities or operators without any repercussions. Even then, it is not clear whether a third-party will have the ability to avoid revocation of its approval to conduct monitoring simply by completing a corrective action plan.

Response II-14-200: EPA acknowledges the commenters’ concerns; EPA has revised the third-party certification and criteria as explained in Section X.C.2 and XI.C.2. These revisions include requirements for when you must recertify and expanded circumstances for being removed from the list of approved third-party notifiers.

Comment: (2326-AXPC) states that even under EPA’s proposed cure to potential abuse or incompetence, an operator has to petition to have a third party removed, and there is no guarantee that EPA would remove the third party and no criteria (objective or otherwise) is established for when EPA would remove that third party from the approval list.

Commenter (2403-The Petroleum Alliance of Oklahoma) requests EPA establish a transparent process whereby operators can submit a complaint that a technology or the third party should be reconsidered for good cause. This process would include a response and resolution by EPA in a timely manner. This process should include the ability for operators to appeal EPA's decision. EPA should make public its findings and resolution of the issue.

Commenters (2294-Ohio Oil and Gas Association, 2399-GPA Midstream Association) state there should be clear provisions for restricting third parties that are ultimately removed from the approved list. EPA should make clear that individuals removed will be permanently decertified and prevented from reenrolling in the program.

Response II-14-201: As explained above in Response II-14-183, EPA has expanded the circumstance for being removed from the list of third-party notifiers. EPA has provided a pathway in the super emitter reporting requirements for owner or operators to challenge a notification and EPA will track these to identify persistent errors and could take action to decertify third parties.

Comment: Commenter (2393-OSEE) notes the SNPR seems to indicate this could be triggered with three demonstrable errors against a site; however, it later phrases it as three demonstrable errors against an owner operator, which could be interpreted to mean the entire company. Id. Therefore, it should be clarified if EPA intends to allow this for the entire company or only on an individual facility basis.

Response II-14-202: The intent of this provision in the rule was to prevent harassment by a third party of an of an individual facility, we have kept this provision in the final rule and expanded the reporting requirements in the rule to allow for an owner or operator to challenge a perceived erroneous report.

Comment: Commenters (2326-AXPC, 2399-GPA Midstream Association, 2410-California Office of the Attorney General et al.) state the Supplemental Proposed Rule provides no guidance as to how an owner or operator should respond to multiple notifications for the same alleged super-emitter event. Presumably, if an owner or operator receives, for instance, three separate notices of an alleged event, it should perform only one investigation or response applicable to all three notices. The proposed regulatory text, however, should be clarified to avoid a possible interpretation that would read the text as requiring a separate investigation into the same alleged super-emitter event. EPA should clarify that an investigation is tied to an alleged large emissions event, not to each notice of the alleged event.

If EPA requires three erroneous notifications at the same site before any potential action could be taken against a third party's status, commenters (2326-AXPC, 2399-GPA Midstream Association) argue it could result in thousands of inaccurate and faulty determinations. In light of the number of facilities held by one owner or operator (often hundreds or thousands), a third party could target industry (or even the same operator daily) (at one or more locations) without hitting the same facility for several years. This is particularly true if virtually any and all satellite imagery can be used to detect super-emitter events. For example, a third party could simply have



a team of personnel sitting behind their desks reviewing satellite data and producing notifications. And even if they provided one notification per day, an operator with 500 facilities would not see the third notification for several years. Further, if the threshold remains three times at a single facility, antagonistic organizations could readily coordinate to make sure that they alternate attention to a certain area/basin/field and thus prolong the time period for any one third party to hit three notifications. Commenter (2326-AXPC) proposes that there should be no minimum threshold for the number of unfounded notifications provided by a third party before EPA moves to revoke the notifier's status. Or, at a minimum, it should be the total number of faulty notifications provided across all facilities, regardless of the owner/operator of the facilities.

Response II-14-203: If an owner or operator has conducted an investigation into the cause of a super-emitter and that investigation has either identified the cause(s) or confirmed an event is not present, an owner or operator would submit the same investigation report for any super emitter notification of events occurring up to the time investigation.

Comment: Commenter (2365-Climate Action California) recommends that the EPA publish a penalty list for super-emitter events, with fines for an owner increasing with the frequency and severity of super-emitting events over the period of a year.

Response II-14-204: EPA acknowledges the commenter's input.

Comment: Commenter (2483-INGAA) argues EPA is ignoring the benefits that third-party verification can provide. The CARB requires third-party verification for its climate change programs.<sup>171</sup> CARB has hailed the third-party verification requirement as "provid[ing] confidence and reliability in reported data for stakeholders ... and the public."<sup>172</sup> By requiring third-party verification in the Super-Emitter Response Program, EPA would ensure that owners and operators are not subjected to erroneous notice letters that give rise to obligations (even if it is just the filing of a report saying no violation occurred) and give rise to negative reputational impact by being falsely labeled a "super-emitter" on public websites.

Response II-14-205: EPA acknowledges the commenter's input, as detailed in X.C.2 and XI.C.2, EPA has expanded the third-party certification criteria to improve the overall quality of the data and with EPA in a centralized role to provide additional review of the data before EPA providing the notification.

Comment: Commenter (2254-PBPA) states the program has the potential to create significant negative impacts on an operator's "social license to operate"/ESG reputation, even though the third-party super emitter reports could be erroneous, too late to be actionable, or incorrectly identify an operator or a facility. The super emitter reports will be posted on an EPA website, and flaring will be included in the annual reports to EPA, which are also publicly available. For

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<sup>171</sup> 17 CCR § 95103(f) (California Regulation for the Mandatory Reporting of Greenhouse Gas Emissions); 17 CCR § 95977 (California Carbon Cap-and-Trade Program), 17 § CCR 95491.1(d) (California Low Carbon Fuel Standard Regulation).

<sup>172</sup> CARB, LCFS Verification, [www.arb.ca.gov/lcfs-verification](http://www.arb.ca.gov/lcfs-verification).

instance, a report could misidentify an operator or reported flaring emissions could be in compliance with the EPA rule (not to mention a Railroad Commission or state analog regulation). As such, EPA should amend the program to require detections to be shared with the operator within the same time period after detection as required for operators conducting periodic screening, and the notice should not become public until the accuracy of the report has been verified by the appropriate operator.

Response II-14-206: EPA has revised the program with EPA in a centralized role with EPA receiving data from third parties, providing notifications to an owner or operator, and receiving super emitter reports from the owner or operator. EPA will publish information as we receive information, however EPA does not intend to identify the owner or operator of a site until confirmed by that owner or operator.

Comment: Commenter (2326-AXPC) notes that in the notification and reporting sections of the super-emitter proposed regulations, EPA states that the third party must provide to the operator, and the operator must report, the “[d]ates of detection of super-emitter emissions event and date(s) of confirmation of emission rate.” Thus, this reporting provision makes clear that EPA intends that the notifying entity be required to “confirm” the emission rate that it initially identified. This confirmation must be more than simply reviewing the data and confirming that in fact a suspected super-emitter emissions event exists. Commenter (2326-AXPC) recommends EPA require the third party to confirm (via the same technology utilized initially) that the initially identified emissions rate is ongoing (e.g., conducting another pass over the facility and finding the same results). Such confirmation should be required to occur 24 hours or more after the initial identification. By requiring this confirmation, EPA will reduce the likelihood that third parties provide notice, report to EPA, publicize, and require evaluation by the operator of maintenance events that are already known to the operator or for which the operator has already taken action. Thus, EPA should include language making clear that the notifying entity must identify emissions above the threshold from the same emissions unit as the initial remote monitoring identified.

Response II-14-207: EPA acknowledges the commenter’s input, EPA is not requiring third parties to confirm a super emitter event is persistent although third parties may choose to confirm an event, however the initial detection date would be considered the start of the 15-day period in which they must report.

Comment: Commenters (2249-National Association of Clean Air Agencies, 2399-GPA Midstream Association) add an overall concern with the SERP as described in the proposal is that is vulnerable to “the Twitter problem”: when different parties’ information conflicts, it can create challenges for knowing whose information to trust. The public sector has a responsibility to regulate in the public interest that may not be the institutional first priority of third-party stakeholders like vendors, advocates, and others. Misinformation (and even well-meaning but inaccurate information) can often spread more rapidly than can be countered with supported factual information from credible sources like clean air agencies. When its spread outpaces accurate information, it can dominate public discourse and undermine trust in even the strongest and most credible public institution. By its own admission, EPA states in the supplemental

proposal that EPA would not verify or authenticate the information in third-party reports before posting it online and triggering regulatory action, a concerning detail. The importance of careful implementation of such a program cannot be overstated: the credibility of the federal, state, and local agencies that implement the CAA is indescribably valuable when advancing the protection of clean air for all, and EPA should be prudent about implementing programs that are vulnerable to misinformation that could harm that credibility.

Commenter (2399-GPA Midstream Association) proposes that, in such instances, the affected facility should be able to respond with a letter identifying (1) the cause of the emissions event, (2) how it was abated, and (3) when it was abated. The affected facility should not have to waste its resources performing a post hoc mock investigation and corrective action under proposed §§ 60.5371b(c)(1)-(10) for an incident that was already resolved.

Response II-14-208: EPA has revised the program with EPA in a centralized role with EPA receiving data from third parties, providing notifications to an owner or operator, and receiving super emitter reports from the owner or operator.

Comment: Commenter (2157-Division of Air Pollution Control Tennessee Department of Environment & Conservation) states the only penalty for a notifier submitting incorrect reports would be removal from the approved list following an impacted facility's successful petition following receipt of three incorrect reports.

- The Supplemental Proposal states that “EPA faced a similar situation when establishing standards for petroleum refineries, where cost-effective controls and inspections of equipment and operations would not have addressed potentially significant levels of emissions that could occur between regular inspections.” In that instance, EPA required fence-line monitoring for timely identification of significant increases in emissions<sup>11</sup>. The circumstance that EPA describes is not similar because petroleum refineries were required to conduct their own fence-line monitoring. Here, EPA proposes to allow third party notifications to create immediate response and corrective action requirements.
- The proposed rule specifies no requirement for periodic recertification of third parties.
- The proposed rule does not explain how EPA will ensure that those removed from the approved list cannot simply change organizational identification information in order to be re-approved and placed on the list again.

Response II-14-209: EPA acknowledges the commenters' concerns; EPA has revised the third-party certification and criteria as explained in Section X.C.2 and XI.C.2. These revisions include requirements for when you must recertify and expanded circumstances for being removed from the list of approved third-party notifiers.

Comment: Commenter (2257-Michigan Oil and Gas Association (MOGA)) questions how the EPA's proposed “super emitter” program and associated remote-sensing technologies will be able to account for wetlands adjacent to oil and natural gas operations. The EPA's proposed third-party certification of technology for monitoring releases from oil and natural gas operations does not address the ability of technology to control for background sources of Methane from

wetlands, cattle operations, etc. when determining fugitive emissions. The commenter and their constituents have provided numerous comments regarding the complexity of State of Michigan wetland protection rules often resulting in oil and natural gas wellheads and facilities being located immediately adjacent to both small and large wetland complexes. Naturally, Michigan has more wetlands than Texas, which once again, illustrates the one-size-fits-all approach is not valid across all oil and natural gas-producing states.

Commenter (2446-IPAA) asks how does the third-party notifier and/or EPA pinpoint the source and to the extent, how do they identify who owns or has responsibility for the source? Additionally, how does the third-party notifier and/or EPA know what regulations, in any, apply to the "source" in question – if the "source" is not an affected facility or designated facility, Section 111 is not violated?

Response II-14-210: EPA acknowledges the commenters' concerns; EPA has included a requirement that ant technology used for the Super Emitter Program must be approved through the advance methane detection technology program in the rule, this would require technology to verify the spatial resolution needed for the Super Emitter Program and the method used for this technology would need to account for potential background methane.

#### ***14.5.8 Publicly Available Database***

Comment: Commenters (2195-Environmental Health Project, 2299-NEI Investments, 2303-NTAA, 2392-Earthjustice et al., 2394-Earthworks, 2403-The Petroleum Alliance of Oklahoma, 2425-Taxpayers for Common Sense (TCS), 2433-EDF et al, 2444-NAACP, 2447-Clean Air for the Long Haul, 2453-Carbon Mapper and RMI, 2462-Cynthia Walter, 2626-Kayrros) state all pertinent information should be made publicly available and easily accessible on a centralized website as soon as possible. Changes to strengthen SERP will benefit Black, Latine, tribal, and rural and low-income communities that live in close proximity to oil and gas infrastructure. The improvements to SERP would require that owners and operators timely identify and take corrective action to stop harmful air emissions that disproportionately impact these communities. Streamlined operator and public notification processes will also allow members of these impacted communities to take action to protect themselves during emission events to the extent possible.

Commenter (2444-NAACP) states although previous iterations of the proposed rule in November 2021 ensured that communities retained the ability to monitor methane and other emissions, the December 2022 version of the rule weakens that ability.<sup>173</sup> The commenter requests that the EPA ensure and strengthen the operation of community monitoring of methane and other emissions.

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<sup>173</sup> Subpart OOOOb—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After November 15, 2021, available at [https://www.epa.gov/system/files/documents/2022-11/8510\\_OilandGasClimate\\_OOOObRegText\\_Supplemental\\_20221005.pdf](https://www.epa.gov/system/files/documents/2022-11/8510_OilandGasClimate_OOOObRegText_Supplemental_20221005.pdf).

Commenter (2433-EDF et al) argues publicizing this information is consistent with EPA's past practices around emissions data and with the requirements of the CAA, which ensure emissions data are not treated as confidential.<sup>174</sup> Further, given that these emissions will be detected by third parties, it would be difficult or impossible for those data to not be publicized, as those entities could publish it on their own websites. To avoid inconsistent treatment of this information, EPA should make it all publicly available in real time on a single, centralized website.

Response II-14-211: EPA recognizes the commenters concern and while we cannot directly address your concern, the Super-emitter program is being developed with transparency in mind, on the part of the third-party, the EPA, and the owner or operator. All notifications meeting the requirement in the final rule will be published online on the EPA's Super Emitter Portal - <http://www.epa.gov/super-emitter>.

Comment: Commenters (2303-NTAA, 2433-EDF et al, 2453-Carbon Mapper and RMI) state the website should also include geographic and operator information, as well as links to the corrective action plan and other relevant follow-up information.<sup>175</sup> A centralized database with geographic coordinates and ownership information can streamline and ensure detections are accurately attributed to the correct site and operator. EPA should also centrally maintain information including the site type (e.g., fugitive monitoring subcategory), geographic location, responsible owner or operator, as well as other relevant records (e.g., fugitive monitoring plan and scheduled maintenance events), so that investigations after third-party notifications are efficient.

Commenter (2462-Cynthia Walter) asks EPA to make up to date information readily available to the public regarding details, e.g., location, amounts and types of emissions, remediation work schedule, contact for local agency supervisors. Without this, residents near oil and gas operations cannot avoid exposure to substances reported from such sites as in Macey et al. 2020<sup>176</sup>

Response II-14-212: As explained above in II-14-194, All notifications meeting the requirement in the final rule will be published online on the EPA's Super Emitter Portal - <http://www.epa.gov/super-emitter>. This notification will include a precise location of these super-emitter events.

Comment: Commenters (2360-Devon, 2399-GPA Midstream Association) state EPA should consider an appropriate manner in which to disclose information to the public. The commenters have participated in voluntary emission detection programs, such as The Environmental Partnership, where detected emission events were effectively relayed to operators for follow-up and mitigation if necessary. Through this voluntary program, operators were also encouraged to share their emission mitigation and reduction strategies for the benefit of the broader industry.

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<sup>174</sup> 42 U.S.C. § 7414(c).

<sup>175</sup> See, e.g., Permian Methane Analysis Project, <https://data.permianmap.org/pages/operators>; Carbon Mapper Data Portal, <https://carbonmapper.org/data/>.

<sup>176</sup> Macey et al. 2014. Air concentrations of volatile compounds near oil and gas production: a community-based exploratory study. *Environmental Health* 2014, 13:82 <http://www.ehjournal.net/content/13/1/82>.

EPA could craft a similarly effective program by publishing a report or commissioning a third party, such as an academic institution, that summarizes the types of events discovered, the subsequent corrective actions, and the general locations where the events were discovered. Operators could be incentivized to respond if the failure to adequately address the event resulted in operator specific details being published in the same report.

Commenter (2360-Devon) states a framework that enables reliable detection information to be relayed to an operator with a high degree of specificity, encourages effective and reasonable mitigation and response from the operator, facilitates the sharing of event cause and mitigation techniques that is non-operator specific, provides meaningful information to the surrounding communities, and specifically identifies those operators that fail to respond, could result in a program that allows qualified third parties to participate in a way that is constructive, legally durable, and ultimately results in effective emission reductions.

Response II-14-213: EPA acknowledges the commenter's input.

Comment: Commenters (2202-TXOGA, 2213-Oxy, 2220-WDEQ, 2227-Western Energy Alliance, 2237-Industrial Commission of North Dakota, 2283-Endeavor Energy Resources, 2298-Pioneer Natural Resources USA, Inc., 2248-NDPC, 2258-MSR, 2326-AXPC, 2315-DEC, 2345-GHGSat Inc., 2366-BHE, 2389-ACC, 2391-CEC, 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API, 2446-IPAA, 2483-INGAA) believe all data and notices from approved third parties should first go to EPA and/or the state to review. EPA and/or the state delegated agency would contact the operator of the facility to verify the event and take corrective actions if appropriate. EPA and/or the state delegated agency should review the data and operator's findings for each super emitter event before any information is released to the public.

Response II-14-214: EPA acknowledges the commenters' input; The final rule has been revised to include a process where EPA will review all third-party data submitted and determine whether a notification to an owner or operator is accurate and reasonable before sending a notification to an owner or operator.

Comment: Commenter (2483-INGAA) recommends the following text changes to §§ 60.5371b(b)(7) and 60.5388c(b)(7) of the proposed rule:

(7) The notifier must submit the notification as soon as practicable to the owner or operator of the site with the super-emitter emissions event. The notifier must also submit a copy of the notification to the Administrator and to any delegated authority on the same day that notification is made to the owner or operator. The Administrator shall make such notifications publicly available at [webpage] only after it is confirmed that a super-emitter emissions event requiring corrective action occurred.

Commenter (2483-INGAA) recommends the following text changes to §§ 60.5371b(e)(4) and 60.5388c(e)(4) of the proposed rule:

(4) Upon receipt of the report required by paragraph (e) of this section, the Administrator shall make such report publicly available at [website] only if the report confirms that a super-emitter emissions event requiring corrective action occurred. Any confidential business information contained in the report shall be redacted from the publicly available report.

Response II-14-215: EPA acknowledges the commenters' input.

Comment: As the proposal is written, Commenters (2168-INOGA, 2172-Kentucky Oil and Gas Association, 2220-WDEQ, 2298-Pioneer Natural Resources USA, Inc., 2326-AXPC, 2354-Business Roundtable, 2366-BHE, 2389-ACC, 2391-CEC, 2428-API) argue there will be reputational damage to the owner/operator for allowable activities or as a result of erroneous or premature reports. These reported releases could lead to an owner/operator being labeled as a "super emitter," and even if the allegation is found to be erroneous later, the mere fact that an owner/operator got a notice will have a deleterious impact on the owner/operator's reputation.

Commenter (2483-INGAA) adds, EPA needs to address issues related to confidential business information and how that information will be protected from public disclosure. For example, the report that an owner or operator files following a super-emitter event may contain information on the owner or operator's specific procedures and practices, a root cause or investigative analysis, and information such as flow diagrams, which in some instances may constitute confidential business information or otherwise sensitive information related to critical infrastructure. EPA needs to address how this information will be protected.

Commenter (2389-ACC) states EPA proposes that any notification include a substantial amount of potentially sensitive information, including facility location and latitude/longitude coordinates, depictions of emissions and the site, emissions rate, and date and time of emissions event, among other aspects.<sup>177</sup> EPA later proposes that it would make these notifications available to the public. The public and rapid release of the sensitive information could result in potential security and operational concerns for facilities that are facing an ongoing emissions event.

At a minimum, commenters (2389-ACC, 2428-API) state EPA should limit the information for super-emitter emissions event so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

Commenter (2428-API) states participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring,

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<sup>177</sup> 87 FR 74750.

where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

Commenter (2428-API) states monitored data should not be published without context from operator feedback or corrective actions. EPA's state within the preamble (87 FR 74750) "owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated." While the commenter agrees with this concept, the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While the commenter concur that data transparency is valuable and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

Response II-14-216: EPA has revised the program with EPA in a centralized role with EPA receiving data from third parties, providing notifications to an owner or operator, and receiving super emitter reports from the owner or operator. EPA will publish information as we receive information, however EPA does not intend to identify the owner or operator of a site until confirmed by that owner or operator.

Comment: Commenters (2389-ACC, 2428-API) recommend EPA establish a protocol or annual publication updating on progress of the program. Given the ambiguity present in proposed §60.5371b(e)(4) for a new EPA website to host these reports, there is a high probability that third-party monitored data will provide very limited context for the general public and can be easily taken out of context. The commenters believe a synthesized annual report or fact sheet published by EPA would offer a more clear depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, and the types of corrective actions that were taken to repair other super emitter emissions identified. Information that would easily identify the operators could be blinded in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct contact information).



Commenter (2453-Carbon Mapper and RMI) agrees with the above commenters, stating EPA should maintain a public database of all super-emitter notifications by certified third-party reporters with updates on an annual basis including mitigation reports by operators where available.

Response II-14-217: EPA recognizes the commenters concern and while we cannot directly address your concern, the Super-emitter program is being developed with transparency in mind, on the part of the third-party, the EPA, and the owner or operator. All notifications meeting the requirement in the final rule will be published online on the EPA's Super Emitter Portal - <http://www.epa.gov/super-emitter>.

Comment: Commenters (2237-Industrial Commission of North Dakota, 2288-NDDEQ) state the revised proposal requires that the Administrator shall make the initial notification and corrective action report publicly available via a webpage in the case of the notifications or a website in the case of the reports. There is no clear timeline for when the Administrator needs to accomplish this, though for the reports, 60.5388c€ (4) does mention "Upon receipt". If EPA intends for the NDDEQ to be making these documents publicly available, the NDDEQ recommends simply stating such, without additionally defining a timeline or a place. With the development of any program, timeframes and publication locations may necessitate changes that would be hampered if only one particular method is defined in the model rule.

Response II-14-218: EPA acknowledges the commenter's input; EPA has the obligation to post notifications and reports consistent with the requirements in the rule as explained in Section X.C.2 and X.C.4 of the preamble of this rule.

Comment: Commenter (2428-API) states any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

Response II-14-219: As detailed in Section X.C.2 and XI.C.4 of the preamble of the final rule, EPA has revised the final rule to include reporting corrective actions as part of the super emitter program. When an owner or operator is notified of a super-emitter event, they are required to conduct an "investigation" and report back to the EPA per the requirement in the applicable NSPS and/or EG.

EPA may use any credible evidence to establish a violation. If an owner or operator, upon conducting the required investigation, determines that a deviation from an applicable standard has caused the super emitter event, then the owner or operator must comply with the requirements in NSPS OOOO, OOOOa, OOOOb and/or EG OOOOc to correct and report the deviation. The Super Emitter Program does not create a safe harbor for violations of Clean Air Act regulations.

### 14.5.9 Trespassing

Comment: Commenters (2166-Ohio Department of Natural Resources, Division of Oil and Gas Resources Management (ODNR), 2168-INOGA, 2172-Kentucky Oil and Gas Association, 2220-WDEQ, 2221-Texas Pipeline Association, 2227-Western Energy Alliance, 2237-Industrial Commission of North Dakota, 2258-MSO, 2288-NDDEQ, 2326-AXPC, 2360-Devon) are concerned with portions of the draft rule that state citizens would be authorized to enter private lands for emissions measurements. This will create unnecessary safety risks and problems with citizens trespassing. The requirement should be put in place to disallow unaccompanied access onto sites without operators, prerequisite notification to the operator, and verified sufficient safety training to permitted parties.

Response II-14-220: EPA acknowledges the commenters' input; EPA has revised the final rule to include criteria for certification of third-party notifiers explained in Section X.C.2 of the preamble of this rule. EPA agrees that unauthorized access to a facility through private or public lands creates a potential safety risk, if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification will be revoked.

Comment: Commenters (2326-AXPC, 2360-Devon, 2428-API) state there are potential safety concerns associated with members of the public accessing sites without proper notice, personal protection equipment (PPE), and training. For example, some sites can contain hydrogen sulfide (H<sub>2</sub>S), a gas that could result in serious health issues for members of the public without proper protection. Well sites are located on private property. EPA's proposal could encourage members of the public to trespass onto private property and to avoid safety signs and considerations. This could result in members of the public hurting themselves or damaging equipment that could result in putting workers in danger. There is also the question of who would be liable for the safety of the members of the public who illegally trespass on the property or for any damage that they may cause.

Commenter (2428-API) states even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (*e.g.*, mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no "fencing") with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at the commenter's (2428-API) facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example,

training specific to the presence of hydrogen sulfide (H<sub>2</sub>S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Commenter (2428-API) states individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. Commenter (2428-API) recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. Trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

Response II-14-221: As explained above in Response II-14-202, if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification will be revoked.

Comment: Commenter (2346-Encino Environmental Services, LLC) argues allowing satellite access to become community data (without proper controls) presents (potential) risk to National Security and the U.S. energy apparatus.

Response II-14-222: EPA acknowledges the commenters' input.

Comment: Commenters (2237-Industrial Commission of North Dakota, 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma) have concerns that the super-emitter program invites safety and trespass issues even though EPA states they are allowing the use of remote-sensing aircraft, mobile monitoring platforms, or satellites to identify super-emitter events. For example, the use of mobile monitoring may encourage entities to drive on oil and gas locations to collect emission information, thinking it is safe and acceptable. These entities may not be aware or trained on the many safety risks associated with a well site or that's it is an illegal trespass without the operator's approval.

If EPA intends "mobile monitoring platform" to mean that third parties may use drones, commenters (2258-MSC, 2399-GPA Midstream Association) urge EPA to consider fully the implications of approving and encouraging the use of that technology, as the proposal provides no procedures or limitations on the use of drones. Private parties flying drones over or through a facility not only could be an illegal trespass, but it would undoubtedly present a major safety hazard, including at unmanned facilities. Accordingly, EPA should develop proper monitoring procedures to prevent third party notifiers from placing themselves or others at risk of personal injury or jeopardizing the security of an operator's property, including clear direction that third party notifiers must not be allowed to encroach on an operator's property to conduct monitoring.

Commenter (2258-MSC) adds usage of drones for monitoring is of particular concern as it requires Federal Aviation Administration certification and may employ equipment that is not

intrinsically safe. This should be specifically addressed in the requirements for certification of third-party entities.

Response II-14-223: As explained above in Response II-14-202, if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification will be revoked.

Technology used for the super emitter program must be approved for use in the Super Emitter Program, EPA will evaluate the use of UAS in this program to make sure that all federal, state, local, and/or tribal regulations are followed.

Comment: Commenter (2393-OSEE) notes in the preamble of the SNPR, EPA states that “several commenters raised concerns regarding potential safety or trespassing on sites with a program using more ground based or close-range detection methods.” 87 Fed. Reg. 74749. EPA cites the OSEE/ODEQ 2021 Comment as support for this statement, implying the cited commenters preferred satellite detection methods over ground-based detection methods for detecting super-emitters due to safety and trespassing concerns. The OSEE/ODEQ 2021 Comment did state concerns regarding safety of the public in community detection programs, but not with respect to detection methods (See OSEE/ODEQ 2021 Comment, Comment 5). The context of the comment at issue was to express concerns about allowing third parties to detect large emission events that would require owners/operators to mitigate those events. It was not coupled with a statement of preference for satellite systems. In fact, in the very next comment (Comment 6 to OSEE/ODEQ 2021 Comment), Commenter (2393-OSEE) and ODEQ stated that “OSEE and ODEQ note that the use of satellite data as the threshold could be problematic. For example, there could be large emission events that are not visible on satellite due to cloud cover or inadequate timing of satellite imagery for emissions that do not have a constant temporal profile, among other factors.”<sup>178</sup> While the commenters realize that a satellite system would mitigate some of the aforementioned safety risks, these concerns remain valid, and Commenter (2393-OSEE) and ODEQ maintain that third-party monitoring remains problematic in general.

Response II-14-224: EPA acknowledges the commenters’ input.

Comment: Commenter (2393-OSEE) notes ODEQ has already dealt with burdensome issues involving notifications from third parties about methane releases detected by satellite systems. For example, in October of 2021, ODEQ was contacted by a media company about one such methane release. ODEQ investigated the event based on the latitude and longitude coordinates given by the media company and contacted various companies operating in that area. The accuracy of the location made it difficult to determine which company/facility caused the event. When it was determined where the release came from and contact with the company was completed, the methane release was found to have originated from a section of pipeline that needed to be blown down due to maintenance activities. Thus, being a pipeline, this release did not

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<sup>178</sup> See “State of Oklahoma’s Comments on EPA’s Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review” Document ID EPA-HQ-OAR-2021-0317-0727.

originate from a facility that would be subject to the requirements of Subparts OOOOb or OOOOc and therefore would not be considered a super-emitter in this program. Also, the estimated release was 116 tons/hour based on the satellite data. Yet, based on the size of the pipeline, the company verbally indicated that the release was much lower than this estimated amount from the satellite.

Commenter (2393-OSEE) continues, ODEQ was notified a second time of a release in a different location in January of 2022. This time, when ODEQ contacted nearby companies based on the latitude and longitude coordinates given, no company reported any potential releases. ODEQ inspected the area with a forward looking infra-red, or FLIR, camera to see if any leak could be found using OGI, however no leaks or super-emitters were discovered. ODEQ contacted various companies with pipelines in the area and none indicated any issues. It is suspected that the release may have come from a pipeline, which would not be subject to the requirements of Subparts OOOOb or OOOOc. Significant resources were used by various companies and ODEQ to try to find this event, yet no super-emitter was identified, nor was a reduction of emissions achieved. With these two examples in mind, it becomes clear that it is vitally important that the satellite systems are accurate enough to determine precise locations to avoid false accusations and the waste of state resources.

Commenter (2393-OSEE) states while a satellite-centered program run by states or EPA could potentially still have issues, it is bound to at least be more accurate and efficient than relying on third parties. Third parties could still work directly with industry if both parties agree, or third parties could report their findings directly to the state or local agencies or even to the EPA. But third-party reporting should not trigger any immediate obligation by the facility until verified by state regulatory personnel who would initiate a response. Only notification by a government agency should trigger a requirement for industry to respond. In fact, ODEQ already has mechanisms in place for this, as it would fit into ODEQ's Environmental Complaints Program. ODEQ's Environmental Complaints Program is a robust program that sets forth specific timelines for communication with the complainant that have been established within ODEQ's regulations. The program has a uniform investigation process, a central repository for all complaint records, and direct continuous involvement with each citizen who lodges a complaint.

Commenter (2393-OSEE) argues removing third parties' ability to engage facilities in enforcement would also mitigate some of the environmental justice concerns raised. This is because, while it would still be possible for wealthy communities to hire consultants to look for leaks, these activities would still require that a government agency act as an intermediary to verify the problem and oversee the response.

Response II-14-225: As described in Section X.C and XI.C, EPA has structured the Super Emitter Program to redefine the obligations of the third-party notifier, EPA, and owner or operators.

These revisions have been included to improve the overall quality of the super emitter data being provided to the program, includes regulatory review of the data by EPA, and defined responses by the owner or operator.

Comment: Commenter (2177-Ute Indian Tribe) sees third-party reporting as a direct attack on Tribal sovereignty as this proposed program would essentially allow individuals unauthorized access to Tribal lands. Moreover, the commenter has qualified staff to issue these notices, and deference should be given to our Tribe's Air Quality Program. The EPA should strongly consider taking into account tribal law which governs who can enter tribal land and enter into consultation with tribes before proceeding with this program. Further, this program is proposed without a tribal exemption, which not only violates the EPA's own statements regarding implementation of tribal lands but also the principle of FPIC. This program has not been discussed with tribal leaders.

Response II-14-226: EPA acknowledges the commenters' input, The final rule also lists circumstances under which a third-party certification will be revoked, including the engagement in an unlawful action (*e.g.*, trespass) when monitoring for super-emitter events.

Comment: Commenters (2166-ODNR, 2288-NDDEQ) state most wells in Ohio are located on private property, and the guidelines include no language regarding how Ohioans, law enforcement, or state regulators will know who is authorized to be on the property. There are no standards established for calibration of equipment that ensure readings are measured correctly or for remedies landowners or operators may take should emissions be read incorrectly. Commenter (2166-ODNR) adds there is no language regarding where liability rests should injury to persons or property occur.

Commenter (2288-NDDEQ) is concerned that the approval process for third-party monitors may give the perception that such third-party monitors are acting on either the EPA or the NDDEQ's behest. In addition, for third-party monitors employing ground-based technologies, it must be made clear that private property rights as well as restrictions around national defense installations that exist near exclude oil and natural gas facilities must be respected, Notifier approval should not grant or imply any sort of property access to the third-party notifier.

Response II-14-227: EPA acknowledges the commenters' input; EPA has detailed the criteria for third parties in Section X.C.2 and XI.C.2 of the preamble of the rule. The rule also includes a provision that if the third-party notifier is guilty of illegal activity during the assessment of a super-emitter event (*e.g.*, trespassing), their certification would be revoked.

## **14.6 Statutory Basis for Super Emitter Program**

Comment: Commenters (2410-California Office of the Attorney General et al., 2433-EDF et al.) agree with EPA's conclusion that the SERP is legally justified either by treating super emitter emission events as a separate source of emissions for which the SERP is the BSER, or by incorporating the SERP into the performance standards and presumptive standards for facilities as an additional compliance assurance measure or work practice standard.<sup>179</sup>

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<sup>179</sup> 87 Fed. Reg. at 74,752–54.

Response II-14-228: EPA acknowledges the commenter’s input; EPA has detailed the statutory authority in Section X.C.1 and XI.C.1 of the preamble of the rule.

Comment: Commenter (2433-EDF et al.) states because super emitters disproportionately contribute to total emissions and have a significant impact on the communities where they are located, EPA has explained that the SERP program is necessary to “backstop compliance and address the unique characteristics of these events.”<sup>180</sup> EPA, thus provides two separate statutory bases to support the program.

Commenter (2433-EDF et al.) notes first, EPA proposes that super emitter emission events are separate and distinct affected and designated facilities, with SERP serving as the “best system of emission reduction” for these sources. Under this proposal, a super emitter affected or designated facility is defined as “any equipment or control device . . . at a well site, centralized production facility, compressor station, or natural gas processing plant” that causes a release with a quantified emission rate of 100 kg/hr of methane or more.<sup>181</sup> Given that these events occur as result of malfunctions or abnormal operations, the BSER for these events would be corrective action to address the malfunction or abnormal operation that caused the emission event in order to resume normal operation, in accordance with the program parameters set out by EPA.

Commenter (2433-EDF et al.) notes second, EPA explains that SERP is justified as a backstop to ensure compliance with the other standards and requirements included in the rules that apply to affected and designated facilities, a number of which are known sources of super emitter emission events. EPA proposes to incorporate the program as an additional compliance assurance measure for sources that are subject to numeric standards of performance and control device requirements and as an additional work practice standard for sources subject to that type of standard in the rules. For sources that are subject only to work practice standards, like a collection of fugitive emission components, EPA proposes that the BSER for those sources includes targeted root cause analysis and corrective action for super emitter events. Again, as noted above, if a source subject to a numeric, control device, or work practice standard has a super emitter event, it is very likely that the source would be out of compliance with the applicable standard and the source would already have to take corrective action to come back into compliance with the applicable standard.

Response II-14-229: EPA acknowledges the commenter’s support of the Super Emitter Program.

Comment: Commenters (2227-Western Energy Alliance, 2254-PBPA, 2326-AXPC, 2399-GPA Midstream Association) state in the preamble to the proposed rules, EPA did not explain the legal basis and whether such a regulation is even legal. This lack of explanation or even rational basis is the hallmark of arbitrary and capricious federal rulemaking, that is not supported by the law, in violation of the Administrative Procedures Act. EPA’s failure to explain the legal authority and supporting legal rationale for this key element of the proposed rules is also a

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<sup>180</sup> 87 Fed. Reg. at 74747.

<sup>181</sup> Id. at 74752.

violation of EPA's obligation under the CAA to include as part of the proposed rules "the major legal interpretations ... underlying the proposed rule." 42 U.S.C. § 307(d)(3)(C).

Commenter (2403-The Petroleum Alliance of Oklahoma) argues the Proposed Rule is unclear on how super emitter events will be used by EPA and/or state delegated agency as it relates to enforcement.

Response II-14-230: EPA acknowledges the commenter's input; EPA has detailed the statutory authority in Section X.C.1 and XI.C.1 of the preamble of the rule.

EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

Comment: Commenter (2353-CrownQuest Operating, LLC.) states EPA's attempt to establish a super emitter program significantly oversteps its authority in the CAA. Equipment failure or operating conditions that usually resolve themselves cause most of these "super emitter" events. The EPA even states that operators will not be allowed a defense if the EPA checks their facility and finds no significant emissions. EPA acknowledges that some events they are concerned with are not part of normal operations. Instead, these events are due to factors outside the operator's control and will resolve themselves. The EPA should stay within its statutory bounds and not attribute upset conditions to operators or deputize third parties to act as their agents. If the EPA needs more money to monitor these events, it should ask Congress for the funds or the authority to deputize third parties.

Response II-14-231: EPA acknowledges the commenter's input; EPA has detailed the investigation requirement for owners or operators in the event they are notified of a Super Emitter Event in Section X.C.2 and XI.C.4 of the preamble of the rule. The investigations are intended to identify the potential cause(s) of these emissions and take into account allowed emission events in these investigations.

Comment: Commenter (2237-Industrial Commission of North Dakota) contends the program undermines their entire legitimate role under the cooperative federalism structure of the statute. North Dakota treats every complaint seriously and would investigate a notification of a super emitter event whether it came from an EPA approved third-party or not. This assumes EPA would remain the administrator for the super emitter program, however §60.5373c does not list the SERP as an authority that EPA will retain.

Response II-14-232: EPA acknowledges the commenter's input; the statutory basis ***of the rule has been explained in Section X.C.1 and XI.C.1 of the preamble of the rule.***



### **14.6.1 State Law**

Comment: Commenter (2403-The Petroleum Alliance of Oklahoma) states EPA provides no statutory authority that allows it to “farm out” its and/or the state’s regulatory duties to third parties. This is unwarranted and a drastic departure from long-standing established processes and protocols that require the EPA and/or the delegated state agency to manage compliance of a regulated entities. Typically, states are in the best position to address this issue, have citizen reporting processes in place and are familiar with the regulated entities in their state. As such, we don’t think a separate SERP that bypasses EPA and/or states delegated regulatory jurisdiction is warranted.

Response II-14-233: As described in Section X.C and XI.C, EPA has structured the Super Emitter Program to redefine the obligations of the third-party notifier, EPA, and owner or operators.

Comment: Commenters (2218-TCEQ, 2283-Endeavor Energy Resources, 2301-U.S. Chamber of Commerce) note Commenter (2218-TCEQ) has an existing process to accept evidence from citizens, and evaluates evidence provided in accordance with agency procedures. State law provides the commenters authority to take enforcement action when appropriate. This proposed rule requires receiving, evaluating, and approving requests for verified third parties and solicits information from other entities that will create a potentially extensive additional workload for the commenter without additional funding or support. The scope of investigations will broaden and there may be additional investigations triggered by complaints to enforce the SERP. Compliance staff will be required to engage in ongoing technical discussions with both the regulated entity and verified third parties to implement the program. The EPA should reconsider the overall effectiveness and necessity of the super emitter program given the significant resource burden the program will have on states.

Commenter (2283-Endeavor Energy Resources) states that if EPA does retain the program in a final rule, then EPA should look to comparable state programs, like the one used in Texas by the Texas Commission on Environmental Quality (“TCEQ”), as a model for appropriate safeguards. For example, under the TCEQ program any information collected by a private individual demonstrating “possible violations of law” must be sent to the TCEQ executive director rather than the owner or operator.<sup>182</sup> The TCEQ executive director then evaluates the “value and credibility” of the information provided by the private party before determining whether to initiate an administrative action, refer the case for enforcement, or treat the information received by the individual as a complaint and conduct a complaint investigation.<sup>183</sup> By requiring that private party reports are first evaluated by a regulator, as the TCEQ rule does, EPA would better ensure that operators are not forced to respond to unverified or inaccurate reports and would also help to mitigate the serious statutory and due process concerns presented by the proposed Super-Emitter Response Program.

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<sup>182</sup> See 30 Tex. Admin. Code § 70.4(a).

<sup>183</sup> Id at § 70.4(b)-(e).

Response II-14-234: EPA acknowledges the commenters' input; the final rule includes EPA in a centralized role to receive reports from third parties, reviewing the data, and then if the data is accurate and reasonable, notifying the identified owner or operator. These steps have been included to improve the quality of data being provided to the owner or operator.

Comment: Commenter (2428-API) states throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, "The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify." The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

Response II-14-235: The final rule has been revised as primarily as a compliance assurance program with EPA in a centralized role as explained in Section X.C and XI.C of the preamble of the rule. In the final rule, there is no obligation on the states to track or review reporting by the third party notifiers, EPA's notification to the owner or operators, and/or the responses by the owner or operators back to the EPA.

Comment: Commenter (2393-OSEE) and ODEQ insist the program be run directly by the entities with the actual legal authority to implement and enforce the CAA, be that a properly delegated state/tribal/local authority or EPA. In other words, if EPA insists on creating this program, it should be run like any other program under the CAA using the principles of cooperative federalism. A reliance on third-party notifications could lead to inaccurate data and unnecessary burdens. An EPA-directed program, while not the perfect solution, would address some concerns stemming from the use of third parties, and would allow EPA to reduce the frequency with which new, and more importantly, existing facilities are monitored for methane leaks. This approach would also yield nearly all the methane emission reductions envisioned by EPA for the current proposal. Commenter (2393-OSEE) and ODEQ suggest an alternative with the following elements:

- (1) The Super Emitter Detection and Response Program should be run by an entity that has the actual legal authority to implement and enforce the CAA, i.e., EPA or a delegated air regulatory agency.
- (2) EPA would exempt existing well sites with site-level baseline methane emissions below 3 tons per year (TPY) from fugitive emissions monitoring.
- (3) EPA would reduce the frequency of fugitive emissions monitoring events at well sites, centralized production facilities, and compressor stations; and
- (4) To offset the reduced frequency of monitoring, a new requirement would be added for facilities to require tanker truck drivers who load liquids (crude oil, condensate, or

produced water) from storage tanks to report the condition of the thief hatch on arrival at a site.

Response II-14-236: EPA acknowledges the commenter's input; As described in Section X.C and XI.C, EPA has structured the Super Emitter Program to redefine the obligations of the third-party notifier, EPA, and owner or operators.

#### **14.6.2 CAA**

Comment: Commenters (2218-TCEQ, 2283-Endeavor Energy Resources, 2305-The Williams Companies, Inc., 2310-Montana Department of Environmental Quality (MTDEQ), 2322-Arkansas Department of Energy and Environment, 2354-Business Roundtable, 2399-GPA Midstream Association, 2403-The Petroleum Alliance of Oklahoma, 2428-API, 2452-Hess Corporation, 2483-INGAA) state as proposed, the SERP presents numerous legal,<sup>184</sup> logistical, commercial, safety, and security risks that have not been adequately considered by the EPA. These complex issues would benefit from further discussions between EPA, operators, and other interested parties. EPA should remove the super emitter provision from the rule. As an alternative, EPA could provide states funding (e.g., IRA) to enhance its existing program or develop its own state-specific program to address super emitter emissions.

Commenters (2227-Western Energy Alliance, 2238-SOOGA, 2248-NDPC, 2283-Endeavor Energy Resources, 2294-Ohio Oil and Gas Association, 2301-U.S. Chamber of Commerce, 2305-The Williams Companies, Inc., 2310-MTDEQ, 2322-Arkansas Department of Energy and Environment, 2354-Business Roundtable, 2399-GPA Midstream Association, 2428-API, 2452-Hess Corporation, 2483-INGAA) encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all CAA legal requirements prior to finalizing the requirements (as provided in §60.5371b). Commenter (2305-The Williams Companies, Inc.) states the proposed program is an improper, unilateral delegation of pseudo-enforcement authority not contemplated in the CAA and the program circumvents the well-understood citizen enforcement mechanism that exists in Section 304 of the CAA.

Response II-14-237: The final rule has been revised as primarily as a compliance assurance program with EPA in a centralized role as explained in Section X.C and XI.C of the preamble of the rule. The rule no longer includes the provision to allow third parties to contact the owner or operator directly.

Comment: To the commenters' (2301-U.S. Chamber of Commerce, 2483-INGAA) knowledge, the program would be the first time that EPA has asserted authority under the CAA to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties and without playing any role at all in verifying the information before imposing legal obligations on other private parties. In support of this unusual delegation of regulatory authority, EPA characterizes the program as simply a BSER requiring monitoring and correction of

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<sup>184</sup> See Comment 12.3 and 12.4 of this letters for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

unintentional releases, akin to LDAR,<sup>185</sup> but evades the central concern that it is private parties—not EPA, states, or regulated entities—who would be monitoring, notifying, and triggering the associated regulatory obligations.

For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While Commenters (2305-The Williams Companies, Inc., 2428-API) believe the SERP may be better suited to function as a voluntary based program, members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders. Commenters propose establishing a voluntary program wherein the Agency, industry, and third parties can adequately evaluate the efficacy of this type of program and whether it brings tangible benefits to an emissions reduction regulation.

Response II-14-238: EPA acknowledges the commenters' input.

Comment: Commenters (2237-Industrial Commission of North Dakota, 2283-Endeavor Energy Resources, 2399-GPA Midstream Association, 2483-INGAA) continue, not only is the program not authorized by Congress, this program would be an end-run around the limitations that Congress either expressly established on third-party enforcement or that it knew to be imposed through formal legal proceedings when it passed the CAA. These include, among others, the citizen suit notice provision under 42 U.S.C. § 7604(b)(1)(A) and the diligent prosecution bar under § 7604(b)(1)(B), as well as the need for citizen plaintiffs to demonstrate an ongoing CAA violation, establish Article III standing, and demonstrate to an impartial judge that injunctive relief is warranted. Nothing in the CAA authorizes EPA to run roughshod over these statutory and constitutional requirements and create entirely new private rights.

Commenters (2237-Industrial Commission of North Dakota, 2399-GPA Midstream Association) argue the Supplemental Proposed Rule, despite acknowledging that the SERP would enforce existing regulations, refuses to recognize it for what it is: a private-party enforcement program.<sup>186</sup> Authorization for such a private-party enforcement system is not found in the CAA, and EPA does not claim that the Program is justified by an ambiguity in the statute. Instead, the Supplemental Proposed Rule simply creates an entirely new private-party enforcement mechanism out of whole cloth, despite Congress establishing robust systems for administrative,

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<sup>185</sup> Id. at 74,752 (“[T]he EPA believes that super emitter emissions events from unintentional releases tend to occur as a result of equipment malfunctions and/or poor operations; therefore, the BSER for super emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super emitter emissions event in this proposed rule.”).

<sup>186</sup> Proposed Rule also appears to say that EPA and state agencies could also initiate the SERP to obtain corrective actions. 87 Fed. Reg. at 74,752. The Supplemental Proposed Rule, however, fails to describe such an enforcement action as being grounded in either the Administrator’s emergency powers under 42 U.S.C. § 7603 or any form of enforcement authority identified in 42 U.S.C. § 7413. With respect to State agencies, the Supplemental Proposed Rule never considers whether the SERP is consistent with State enforcement authorities or processes.

civil judicial, criminal, and citizen enforcement. 42 U.S.C. §§ 7413(b)-(d); id. § 7604. EPA should not embark on this extraordinary and unlawful endeavor.

Commenter (2237-Industrial Commission of North Dakota, 2238-SOOGA, 2294-Ohio Oil and Gas Association) add Congress has already spoken to the “deputizing” of third parties for purposes of enforcing the requirements of the CAA - i.e. the CAA Citizen Suit provision (42 U.S.C 7604). Nowhere in the CAA did Congress authorize the SERP that is contemplated under the Supplemental Proposal.

Commenter (2237-Industrial Commission of North Dakota) further notes that the CAA "citizen suit" provision further solidifies this point. 42 U.S.C. § 7604 contains strict restrictions on the types of actions a citizen can initiate, the notice it must provide to alleged violators, and the process in which to do so, including providing the federal District Courts jurisdiction over such actions. If a source corrects alleged violations during the notice period, the complaining citizen generally has no authority to bring an enforcement action. Moreover, citizens also may not bring enforcement actions if either EPA or the State is "diligently prosecuting" the matter. The Supplemental Proposal would empower independent citizen enforcement without any of these procedural safeguards established by Congress.

Commenter (2237-Industrial Commission of North Dakota) contends that citizens would be deputized to monitor air emissions from existing sources, the results of that private citizen monitoring would be presumptively accurate and suitable for enforcement purposes, and those private citizens would be empowered to provide direct notice and claims of alleged violations to owners and operators, after which owners and operators (or States) are not provided any due process ability to contest the allegations in the notice. Upon receipt of these unverified claims, owners and operators of existing sources would be "required to perform a root-cause analysis and take corrective actions to address the emissions source at their individual well sites, centralized production facilities, and compressor stations." 87 Fed. Reg. at 74,747.

Commenter (2238-SOOGA) notes notwithstanding U.S. EPA’s questionable legal authority for establishing the SERP, the regulatory framework for the program needs further development. The Association suggests that U.S. EPA initiate the rulemaking process to approve each technology used by the third-party detectors so that industry has an opportunity to comment on the merit of each technology. The Supplemental Proposal does not provide adequate detail for stakeholders to provide comments as it only identifies the technology by name with no information about the technology and its limitation.

Commenter (2483-INGAA) states EPA’s authority under the CAA is limited to the powers given to it by Congress, and “it may not exercise its authority ‘in a manner that is inconsistent with the administrative structure that Congress enacted into law.’”<sup>187</sup> Section 113 of the CAA, which is entitled “Federal Enforcement,” makes clear that the Administrator is the person who must

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<sup>187</sup> [*FDA v. Brown & Williamson Tobacco Corp.*], 529 U.S. 120, 125 (2000) (quoting [*ETSI Pipeline Project v. Missouri*], 484 U.S. 495, 517 (1988)).

determine whether a violation of the CAA has occurred.<sup>188</sup> Although the CAA does have some circumstances where the Administrator may delegate their authority, it is not to third parties; rather, it specifies that certain of the Administrator's powers may be delegated "to any officer or employee of the Environmental Protection Agency."<sup>189</sup> Section 114 also provides some limited ability of the Administrator to delegate powers, but this is limited to an "authorized representative" for the purpose of entering a facility for inspection purposes<sup>190</sup> or to states when the Administrator finds the procedure developed by the state is adequate.<sup>191</sup> None of these provisions allows the Administrator to delegate to third parties who are unaffiliated with the Agency authority that can give rise to compliance obligations by regulated entities.

Commenter (2483-INGAA) states the power proposed to be given to third parties to require compliance obligations under the SERP is contrary to the powers given to citizens under the CAA. Congress provided citizens with the authority to bring citizen suits against alleged violators of the CAA (including EPA) and prescribed very specific conditions and procedures for how that must be done.<sup>192</sup> Congress also clearly set forth that the citizen suit provision applies to alleged violations of emission standards or limitations under section 111.<sup>193</sup>

Commenter (2483-INGAA) argues none of the conditions or procedures in the citizen suit provision of the statute are present in the proposed SERP. EPA needs to identify the source of its statutory authority to provide third parties with the power to require compliance by a regulated entity and needs to explain why the SERP does not conflict with the citizen suit provision of the CAA, which Congress specifically stated applies to alleged violations of emission standards and limitations under section 111 of the CAA. Lacking statutory authority and with no explanation for why the program does not conflict with Congress's intent in the citizen suit provision, EPA cannot proceed to finalize the SERP.

Response II-14-239: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility. As explained in Section X.C and XI.C of the preamble of the rule with the statutory authority for the rule detailed in subsection 1 of those sections.

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<sup>188</sup> [See, e.g.,] CAA § 113(a)(1), 42 U.S.C. § 7413(a)(1) ("the Administrator finds that any person has violated or in violation of any requirement or prohibition"); [id.] § 113(a)(3), 42 U.S.C. § 7413(a)(3) ("the Administrator finds that any person has violated, or is in violation of, any other requirement or prohibition of this subchapter").

<sup>189</sup> [Id.] § 301(a)(1), 42 U.S.C. § 7601(a)(1).

<sup>190</sup> [Id.] § 114(a)(2), 42 U.S.C. § 7414(a)(2). The third-party reporters under the proposed SERP do not satisfy the requirements to be an "authorized representative" under section 114. EPA's regulations require a third-party "authorized representative" to be an EPA contractor or subcontractor. [See] 40 CFR § 2.301(h)(2)(i).

<sup>191</sup> CAA § 114(b)(1), 42 U.S.C. § 7414(b)(1).

<sup>192</sup> [Id.] § 304, 42 U.S.C. § 7604.

<sup>193</sup> [Id.] § 304(a)(1), (f)(3), 42 U.S.C. § 7604(a)(1), (f)(3) (specifying the citizen suit provision applies to an alleged violation of "an emission standard or limitation" and defining an emission standard or limitation as including "any requirement under section 7411 ... of this title (without regard to whether such requirement is expressed as an emission standard or otherwise)").

Comment: Commenter (2322-Arkansas Department of Energy and Environment) notes under the CAA, Congress granted authority to the states to implement standards of performance, developed by EPA at existing sources of air pollution.<sup>194</sup> Under Arkansas Code Annotated § 8-4-311, the commenter is the entity authorized to:

- develop and effectuate a program for the prevention and control of sources of air pollution in the state (including responding to emissions violation concerns from third-party entities that would implement the Proposed Rule's super emitter program),
- advise, consult, and cooperate with other agencies and with affected groups (including, presumably, third-party entities), to conduct studies, investigations, and research relating to air pollution and its causes, prevention, control, and abatement (including super emitter events addressed in the Proposed Rule), and
- develop and implement state implementation plans addressing air pollution control (including inspection and compliance requirements, which are essentially bypassed by the Proposed Rule's super emitter program).

Response II-14-240: EPA acknowledges the commenters' input.

Comment: Commenter (2237-Industrial Commission of North Dakota) provides that this private enforcement regime would also completely bypass all of the citizen suit procedures established by Congress. EPA does not have the authority to establish a new and vigilante private citizen enforcement regime completely outside the authorities and boundaries established by Congress. For these reasons, the SERP is unlawful and must be withdrawn. Commenter (2237-Industrial Commission of North Dakota) concurs in principle with the goals of the super emitter program; however, they believe the program itself is unnecessary and duplicative of the efforts North Dakota already takes to investigate suspected emission releases and North Dakota's investigations are not limited to "super emitters".

Commenter (2237-Industrial Commission of North Dakota) also contends that the SERP lacks due process for operators or North Dakota in that there is no opportunity to rebut a "citizen" finding that a super emitter event has even occurred, and instead requires operators to take immediate action even if they believe the super emitter event was improperly or incorrectly identified.

Response II-14-241: EPA acknowledges the commenters' input; the final rule includes EPA in a centralized role to receive reports from third parties, reviewing the data, and then if the data is accurate and reasonable, notifying the identified owner or operator.

The final rule includes an allowance for an owner or operator to challenge a third-party notification.

Comment: Commenter (2428-API) concurs the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the

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<sup>194</sup> 40 CFR Part 60, subpart B; and 40 CFR Part 60, subpart Ba.

proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule “the major legal interpretations underlying the proposed rule.” If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

Commenter (2428-API) disagrees with EPA’s contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super emitter events as “monitoring” for an affected facility. As such, super emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA’s preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super emitters – many of which are malfunctions – are or can be independently considered “affected facilities” under CAA § 111.

Commenter (2428-API) also notes that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed SERP, including an extensive explanation of how EPA believes that “[t]he design of the SERP ensures that the EPA will make all of the critical policy decisions and fully oversee the program.” *Id.* at 74749-51. In EPA’s view, “the qualified third-party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized.” *Id.* at 74750. Moreover, such notifications “originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority.” These arguments indirectly speak to EPA’s assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA’s novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

Response II-14-242: EPA acknowledges the commenter’s input; the statutory basis of the rule has been explained in Section X.C.1 and XI.C.1 of the preamble of the rule.



Comment: Commenter (2354-Business Roundtable) believes a better approach might be for a qualified third-party to notify EPA and the relevant state regulatory authority of the emissions.<sup>195</sup> EPA or the state would then decide whether and how to notify potentially responsible owners or operators to initiate required investigation and corrective action. This approach would reduce the risk of inadvertently notifying a non-responsible party and would provide a level of governmental oversight we think is appropriate for the program, assuming any such program is authorized by the CAA.

Response II-14-243: EPA agrees with the commenter and in the final rule, qualified third parties are no longer providing notification to the owner or operators, instead EPA would receive the notification from the qualified third parties, verify the data, then provide notifications to an identified owner or operator.

Comment: Commenter (2452-Hess Corporation) argues the program does not appear grounded in any technical standard, as is required for development of an NSPS pursuant to the plain language of the CAA. EPA appears to have acknowledged the legal novelty of this addition by including two alternative legal frameworks in the “Statutory Basis of Super emitter Program” section of the preamble to the Supplemental Proposal. Given the complexity of this new requirement and potential questions concerning its legal basis, the commenter believes that the SERP is best reserved for a separate notice and comment rulemaking. This would allow the public greater opportunity to evaluate the proposal and provide feedback. Further, there is no reason the SERP must be included in the Supplemental Proposal. It is not otherwise reliant on the standards of the Supplemental Proposal.

Response II-14-244: EPA acknowledges the commenter’s input.

### ***14.6.3 Sections 111, 114, 304***

Comment: Commenter (2394-Earthworks) states the EPA has ample authority to solicit and rely on third-party data in implementing Section 111, and that authority should be used to the maximum extent practicable under the law to expand the SERP. The EPA must provide a clear pathway for communities and third parties to participate and engage in the SERP. The EPA must ensure that data from approved monitoring technologies are accessible to all, including the use of OGI cameras. The commenter urges the EPA to expand the overly restrictive standards within the SERP that would currently limit participation of NGOs and communities who have the tools required to detect pollution.

Response II-14-245: EPA acknowledges the commenter, and the final rule includes a criterion that third-party notifiers into the Super-Emitter Program must be certified. There are no restrictions to being a third-party other than the third party must be an independent entity (i.e.,

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<sup>195</sup> See, for example Gathering and Preserving Information and Evidence Showing a Violation - Texas Commission on Environmental Quality.

someone other than the owner or operator of the site where the super-emitter emissions event is detected, the Administrator, or the delegated authority).

Comment: Commenter (2394-Earthworks) urges the EPA to use the already proposed alternative test method processes under the leak detection and repair program to approve technologies for SERP. Third parties who are certified under SERP should not face a higher barrier to monitoring than operators themselves, as third-party data will likely be more objective than data submitted by operators, who may face conflicts of interest in accurately reporting their own emissions and violations.

Response II-14-246: EPA appreciates this comment, and the rule has been revised to include the requirement that any remote sensing technology used by a third party must be approved under the alternative test method program in the final rule.

Comment: Commenters (2202-TXOGA, 2283-Endeavor Energy Resources, 2292-West Virginia Attorney General et al., 2301-U.S. Chamber of Commerce, 2366-BHE) argue CAA Section 114 does not provide EPA the authority for its proposed super emitter program – it does not authorize EPA to deem unaffiliated third parties to be “authorized representatives” of the Administrator. Indeed, “authorized representatives” must be EPA contractors or subcontractors.<sup>196</sup> Even if such third parties were eligible to be considered authorized representatives, Section 114(a)(2) requires prior presentation of credentials to the source before entering the site or any monitoring is conducted. EPA’s proposal does not satisfy the 114 requirements.

Commenters (2202-TXOGA, 2283-Endeavor Energy Resources, 2292-West Virginia Attorney General et al., 2301-U.S. Chamber of Commerce, 2366-BHE) note CAA section 114 outlines EPA’s authority to establish monitoring requirements and limits that authority to four entities: (1) any person who owns or operates any emissions source; (2) certain entities that manufacture emissions control or process equipment; (3) those with information “necessary for the purposes” of CAA section 114; and (4) those “subject to the requirements of this Act.”<sup>197</sup> The third-party notifiers that EPA describes do not fall within any of these four categories. In addition, the proposed program raises meaningful due process concerns for producers like the commenters who will be required to respond to unverified allegations from third parties in order to prove that they have not violated the law. The proposed program does not include sufficient safeguards to protect owners and operators.

Commenter (2366-BHE) states EPA’s assertion that the proposed program is akin to fenceline monitoring for petroleum refineries and development of an oil spill hotline is erroneous. In the petroleum refinery NESHAP, EPA adopted a work practice standard for operators that requires fenceline monitoring<sup>198</sup> rather than delegating responsibilities to a third-party. In addition, that program includes defined methodologies and implementation requirements for operators. Such structure is lacking for the proposed SERP. The oil spill reporting hotline is a much less

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<sup>196</sup> See 40 CFR 2.301(h).

<sup>197</sup> Id§ 7414(a)(l).

<sup>198</sup> 40 CFR, Part 63, Subpart CC. See § 63.658 Fenceline monitoring provisions.

complicated program than remote monitoring third-party of facility methane emissions and not an analogous program because no special expertise is required by a caller, and, importantly, agency follow-up is triggered by the call.

While commenter (2366-BHE) supports technology development, it is premature to implement a program that relies on the proposed technologies. Commenter (2366-BHE) suggests that EPA initiate a program to support technology and leak mitigation program development and standardization, rather than adopt the SERP. In the interim period between the 2021 proposed rule and the Supplemental Notice, an avenue has been created to support such a development program. The IRA signed into law in August 2022 includes over \$1 billion in funding for natural gas methane programs, including \$850 million to support reporting of methane emission from natural gas operations required by Subpart W<sup>199</sup> of the GHGRP, methane emissions and monitoring from natural gas operations, and mitigation of those methane emissions. That funding provides an ideal platform to develop and execute a research, development and demonstration program that provides the necessary “infrastructure” to apply evolving methane monitoring and quantification technologies.

Commenters (2227-Western Energy Alliance, 2409-BP America Inc.) are concerned that, as written, EPA’s proposed delegation to private third parties in the SERP could be construed as exceeding EPA’s legal authority. EPA contends that it has the statutory authority to create the SERP under Section 111 of the CAA, 42 U.S.C. § 7414, but EPA does not establish how Section 111 authorizes EPA to delegate authority to third parties the ability to trigger new regulatory obligations or become involved in enforcement and compliance issues. Courts have suggested that delegations of such authority by agencies to private entities are “assumed to be improper absent an affirmative showing of congressional authorization.”<sup>200</sup> The D.C. Circuit has particularly expressed concern that “delegation to outside entities increases the risk that these parties will not share the agency’s ‘national vision and perspective,’ and thus may pursue goals inconsistent with those of the agency and the underlying statutory scheme.”<sup>201</sup>

Commenter (2227-Western Energy Alliance) adds CAA sections 111 and 112 allow EPA to transfer primary implementation and enforcement authority for most of the federal standards to state, local, or tribal regulatory agencies. This transfer of authority is called “delegation.” The statute, however, does not authorize EPA to delegate any implementation or regulatory authority to third-party members of the public. While the preamble to the proposed rules contains an

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<sup>199</sup> 40 CFR Part 98, Subpart W.

<sup>200</sup> See *U.S. Telecom Ass’n v. FCC*, 359 F.3d 554, 565 (D.C. Cir. 2004) As the Court explained: “the cases recognize an important distinction between sub delegation to a subordinate and sub delegation to an outside party. The presumption that subs delegations are valid absent a showing of contrary congressional intent applies only to the former. There is no such presumption covering sub delegations to outside parties. Indeed, if anything, the case law strongly suggests that sub delegations to outside parties are assumed to be improper absent an affirmative showing of congressional authorization.” See also *Gentiva Healthcare Corp. v. Sebelius*, 723 F.3d 292 (D.C. Cir. 2013); cf. *Ass’n of Am. R.Rs. v. U.S. Dep’t of Transp.*, 721 F.3d 666, 671 (D.C. Cir. 2013) (noting that, although a statute may not “empower [] private parties to wield regulatory authority [,] [s]uch entities may . . . help a government agency make its regulatory decisions”).

<sup>201</sup> *U.S. Telecom Ass’n*, 259 F.3d at 555-56 (quoting *Nat’l Park & Conservation Ass’n v. Stanton*, 54 F. Supp. 2d 7, 20 (D.D.C. 1999)).

extensive narrative to bolster the policy basis for the Super-Emitter Program, this narrative is devoid of any statutory or legal authority that justifies EPA’s proposal to empower third-party members of the public to monitor and report on regulated facilities, which in turn triggers regulatory obligations for the facility under the rule. Section 111 of the CAA does not convey this authority to EPA. Moreover, EPA cannot lawfully utilize only a policy explanation in the preamble to bridge and account for the absence of any legal authority for EPA to provide for such a regulation.

Commenter (2409-BP America Inc.) is concerned that while EPA claims to maintain control over the “decision making elements” of the program, see 87 Fed. Reg. at 74750-51, certain features of the rule suggest otherwise. For example, to the extent the operator’s obligation is triggered by notification from the third-party without meaningful oversight/involvement EPA, it raises the question whether EPA has delegated authority to determine when (and whether) a regulatory obligation arises, and the operator must act. Further, the fact that the third-party report to EPA may be made available to the public online via the third-party’s own platforms, but that “EPA would generally not verify or authenticate the information in third-party reports prior to posting,” raises similar concerns. *Id.* at 74750 (emphasis added); see also *id.* at 74751.

Commenter (2409-BP America Inc.) argues this does not mean that EPA should abandon its efforts to promulgate a SERP, or that private third parties have no role to play in identifying methane leaks. To the contrary, if it is carefully crafted, Commenter (2409-BP America Inc.) believes that EPA can implement a scheme in which qualified, certified third parties can play an important role in gathering and disseminating information about methane emissions, so that responsible operators may use that information to improve performance, reduce emissions and protect communities, and so that EPA (or states with delegated authority) may use that information to bolster their oversight and enforcement of existing methane standards and regulations.<sup>202</sup>

Response II-14-247: EPA acknowledges the commenters’ support for some aspects of this programs and acknowledges some of their concerns. The final rule no longer includes third party acting as an “authorized representative” under 114(a)(2) and instead has EPA in a centralized role as explained in section X.C.1 and XI.C.1 in the preamble of the rule.

Comment: Commenter (2202-Texas Oil and Gas Association) notes the plainly applicable provisions referenced by the commenter (CAA Section 111(c)) and CAA Section 114<sup>203,204</sup>) provide authority to the “Administrator” and not to private citizens. On its face, CAA Section

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<sup>202</sup> Data and information are important inputs to aid transparency, dialogue and trust-building. bp was an early industry participant in the Environmental Defense Fund’s (“EDF”) Permian Methane Analysis Project (“PermianMAP”). Under this initiative, EDF—a non-profit environmental advocacy group—took periodic methane measurements in the Delaware Basin of the Permian and published this information on a public website. bp engaged regularly with EDF to review PermianMAP data and took any necessary mitigation actions. Engaging constructively with EDF to share feedback and insights as a data-user was a valuable way to enhance our programmatic leak detection and repair efforts.

<sup>203</sup> CAA § 114(a)(1); 42 U.S.C. § 7414(a)(1).

<sup>204</sup> CAA § 114(a)(2); 42 U.S.C. § 7414(a)(2) (emphasis added).

114 nowhere indicates that non-governmental, third-party entities are afforded any authority under the CAA independently to compel a response by an owner/operator or other regulated entity. If the CAA did grant third parties such authority, one might have expected to see some indication of it here.

Commenter (2202-TXOGA) does not perceive the proposal is that an “approved notifier” within the meaning of proposed 40 CFR § 60.5371b(a) would, upon approval, thereby be considered to be an “authorized representative” within the meaning of CAA Section 114(a)(2). Such a designation of private, third-party entity would be problematic in any event.<sup>205</sup> There is nothing to indicate that the agency can authorize non-governmental authorities to exercise the inspection rights of CAA Section 114. If it could, EPA would effectively be able to authorize citizens to become government inspectors that have authority to enter facilities, retrieve data, demand records, and the like.

Commenter (2202-TXOGA) states it is correct that in the specific context of CAA enforcement, the CAA is replete with examples of EPA’s being authorized to take a particular action on the basis of “any information” being made available to the Administrator, which would presumably include information provided to EPA by a private entity. See, e.g., CAA § 113(a)(1) (“... on the basis of any information available . . . .”); CAA § 113(a)(2) (“... on the basis of information available . . . .”); CAA § 113(a)(3) (“... on the basis of any information available . . . .”); CAA § 113(a)(5) (“... on the basis of any available information . . . .”); CAA § 113(d)(1) (“... on the basis of any available information . . . .”). So, while enforcement per se is not in view with respect to the proposed Super emitter Program’s “notification” trigger provision – again, the way the program is devised, a violation would arise only if the owner/operator thereafter failed to take the actions specified under subsections (c) and (d) of proposed 40 CFR § 60.5371b – different considerations are presented where EPA (or a state exercising delegated authority) is the entity doing the notifying under proposed 40 CFR § 60.5371b, even if the information itself on which EPA is relying has come to it from a private third-party entity.

On the other hand, as the commenter had observed in its initial comments, a standard that requires regulated entities to take action on the basis of notification being provided to them by a private third-party entity, of information obtained by and in the possession of that third-party entity, seems unprecedented and even if there is some precedent somewhere, it is not authorized by the CAA.

Commenters (2202-TXOGA, 2254-PBPA) continue, that the Proposed program lacks statutory basis is further highlighted by the role that Congress directly gave to private citizens. Under CAA Section 304, private parties may directly involve themselves in enforcement through the CAA’s citizen suit provision.<sup>206</sup> The citizen suit provision allows private parties to step into the shoes of EPA, or a relevant state, when, following the provision of statutorily required notice, giving the governmental entities an opportunity to take action in the first instance, these

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<sup>205</sup> See *Stauffer Chemical Co. v. EPA*, 647 F.2d 1075 (10th Cir. 1981); but cf. *Bunker Hill Co. v. EPA*, 658 F.2d 1280 (9th Cir. 1981).

<sup>206</sup> See CAA § 304; 42 U.S.C. § 7604.

governmental entities decline to bring a judicial action to address an alleged violation of some emission standard or other provision of the CAA. That the CAA specifically allows for direct involvement (subject to certain conditions) on the part of private entities in the context of enforcement but is otherwise silent when it comes to authorizing private parties to compel directly action on the part of regulated entities, suggests that private parties are afforded no such authority. This is further emphasized by the fact that private parties are clearly subordinate to EPA in their ability to enforce, in that a 60-day notice is required to give EPA the opportunity to take up its own enforcement action on the issue the private citizen seeks to enforce, and if EPA does so, the citizen suit is forbidden.

Commenter (2227-Western Energy Alliance) adds while Section 304 of the CAA expressly prescribes a role for private parties to file civil lawsuits challenging alleged violations of, among other things, CAA §111 performance standards, significantly, Congress did not provide similar express language in CAA §111 or elsewhere in the CAA authorizing citizen monitoring and reporting as provided in the proposed Super-Emitter Response Program. Accordingly, the absence of such language should be construed strictly as a limitation by Congress on EPA's authority to allow such monitoring and reporting by the public. Furthermore, nothing in the statute can be interpreted reasonably that Congress implicitly granted such authority to EPA. Therefore, this provision of the proposed rules is not supported by the law, and EPA cannot lawfully take such action in the final rule.

Response II-14-248: EPA has finalized the Super Emitter Program as a compliance assurance program which was co-proposed in the December 2022 proposal. The statutory authority for the program in the final rule is explained in section X.C.1 and XI.C.1 in the preamble of the rule.

Comment: Commenter (2202-TXOGA) states, accordingly, given that the preamble has yet to articulate a legal basis, grounded in a provision of the CAA, that authorizes it to adopt a Super emitter Program containing the proposed elements, the commenter respectfully objects to the program being finalized as currently proposed. While the December 2022 Supplemental Notice does state that it provides the “statutory basis” of the Super emitter Program, it does not actually do so. All that the preamble really does is explain how the program “fits within the EPA’s authority under section 111 of the CAA.”<sup>207</sup> The preamble does not, however, expressly state that its authority to create the private, third-party trigger requirement is derived from CAA Section 111. In this regard, it offers “two legal frameworks” – in effect, ways of characterizing what is both a novel and creative regulatory construction – into which the Super emitter Program can be fitted, but the Proposal never actually explains the source of the actual authority to create such a program in the first place, given that the proposed program would place such a central, and unprecedented, role in the hands of private entities. This is a role that Congress has never explicitly authorized and that is in misalignment with decades of how the CAA has been enforced.

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<sup>207</sup> 87 Fed. Reg. at 74,752.

Commenter (2202-TXOGA) states first, the Proposal says, “a super emitter emissions event [could be treated] as a separate and distinct source of emissions.”<sup>208</sup> Specifically, EPA is “proposing a new ‘super emitter’ affected facility under NSPS OOOOb (and designated facility under EG OOOOc),” which EPA would then define as “any equipment or control devices, or parts thereof, at a well site, centralized production facility, compressor station, or natural gas processing plant, that causes a Super emitter emissions event (*i.e.*, any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater).”<sup>209</sup> In turn, the “BSER for super emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super emitter emissions event in this proposed rule.”<sup>210</sup>

Commenter (2202-TXOGA) adds second, the preamble says, “the SERP can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule,” a “number of which are known to be frequent causes of super emitter emission events” and which “may not necessarily be identified and addressed through more frequent monitoring that we have determined is not cost-effective.”<sup>211</sup> EPA proposes, therefore, to “incorporate the Super-Emitter Program into these standards by considering the super emitter program” to be “an additional compliance assurance measure, in the case of sources that are subject to numerical standards of performance and associated control device requirements,” and “an additional work practice standard, in the case of sources for which the EPA is proposing work practice standards under this rule.”<sup>212</sup>

Again, nowhere in these statements is the authority identified for establishing a process by which, upon a private, third-party entity’s having pulled a notification trigger, an owner/operator would be compelled to take action or else be deemed in violation of the standard. If EPA itself cannot directly point to such authority, it should strike from its Super emitter Program its proposed private-party trigger provision.

Response II-14-249: The statutory authority for the program in the final rule is explained in section X.C.1 and XI.C.1 in the preamble of the rule.

Comment: Commenter (2433-EDF et al.) disagrees with the above commenters, stating CAA sections 113 and 114 provide legal authority for the program.<sup>213</sup> Section 114 gives EPA broad information-gathering authority to develop standards and emissions guidelines under section 111 and to determine whether a facility is out of compliance with a section 111 standard or guideline.<sup>214</sup> It also permits EPA to require persons with relevant information to provide that information to the agency, set parameters for monitoring methods, and make publicly available

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<sup>208</sup> Id.

<sup>209</sup> Id.

<sup>210</sup> Id.

<sup>211</sup> Id.

<sup>212</sup> Id.

<sup>213</sup> 2022 Joint Environmental Comments, *supra* note 1, at 135–37.

<sup>214</sup> Id. at 135.

any information gathered.<sup>215</sup> Section 113, in turn, allows EPA to engage in an enforcement action based on “any available information” that shows a facility has violated a standard or requirement under the CAA.<sup>216</sup> These CAA authorities further support the SERP program.

Response II-14-250: EPA acknowledges the commenter’s input.

Comment: Commenter (2399-GPA Midstream Association) argues EPA may only regulate two types of sources under Section 111: new sources (including modified sources) and existing sources. 42 U.S.C. §§ 7411(b), (d). A Super emitter Source, as the Supplemental Proposed Rule contemplates it, cannot be a new source under Subpart OOOOb because a new source must be either constructed or modified. Id. §§ 7411(a)(2) (a “new source” is constructed or modified after the publication of the standard of performance regulations), (a)(4) (“modification” requires a “physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source”). Here, a Super emitter Source would be created by an emission event, not any construction or modification.

Commenter (2399-GPA Midstream Association) adds, nor can Super emitter Sources be existing sources under Subpart OOOOc as an existing source is typically constructed and operating before either the approval of a state plan with existing source standards or the issuance of federal existing source standards. 42 U.S.C. §§ 7411(d)(1), (2). Here, however, a Super emitter Source is only created by an emissions event. Even if the source itself is 20 years old, its existence as a Super emitter Source post-dates the issuance of any state or federal existing source standards. And yet, as described above, the absence of construction or modification activities means it cannot be a “new source” under Section 111 either. The Supplemental Proposed Rule never addresses this conundrum, which only arises because Congress never contemplated a source category-shifting scheme like the one proposed here.

Response II-14-251: EPA acknowledges the commenter’s input.

Comment: Commenter (2428-API) notes that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. The commenter pointed out that Congress did not provide similar express language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed SERP. In this context, the absence of such language should be construed as a limitation on EPA’s authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, Commenter (2428-API) states that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain

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<sup>215</sup> Id. at 135, 137.

<sup>216</sup> Id. at 135, 139.



injunctive relief through the SERP (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

Response II-14-252: EPA acknowledges the commenter’s input.

Comment: Commenter (2483-INGAA) argues Section 113 of the CAA makes clear that the EPA Administrator is the person who must determine whether a violation of the CAA has occurred. Congress provided third-party citizens with power to require compliance through section 304, the Act’s citizen suit provision, and the SERP conflicts with that provision. If EPA adopts a SERP despite the lack of authority to do so, it should at least address the issues below.

Response II-14-253: EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

Comment: Commenter (2305-The Williams Companies, Inc.) notes Congress provided one additional mechanism that is arguably a delegation of authority – that is the “citizen suit” provision of the CAA.<sup>217</sup> Section 304 and its interpretive case law support the right of third-parties to collect information about a source that informs the third-party as to the potential compliance status, present that information to the source and the agency with delegated authority (usually a state and/or the EPA), and, if no action is taken after 60-days or if the EPA or other regulatory authority has not already commenced enforcement or is diligently prosecuting the alleged violations, the citizen can bring suit against the violator seeking to enforce the alleged non-compliance. The citizen suit provision allows for an orderly and systematic process by which to evaluate noncompliance allegations brought by third parties.

Commenter (2305-The Williams Companies, Inc.) disagrees with the EPA’s conclusion that the third-party is simply engaging in a “fact-finding activity;” instead upon receipt of a notification from a third-party, an owner or operator has a legal obligation to engage in an immediate investigation into the cause of the “super emissions event” and must report its findings to the EPA in a prescribed period of time. That report is then made publicly available via a publicly accessible website. Not only does this activity circumvent the legal bounds of delegated authority in the Act, but it also evades the strictures of the citizen enforcement provisions Congress articulated in Section 304 of the CAA. The Supplemental Proposed Rule is silent on these requirements and whether the proposed program conforms to the specific conditions that must be satisfied before a citizen can bring an enforcement action against a regulated entity for an alleged violation of a standard.

Response II-14-254: EPA thanks the commenter for their concerns, in the final rule, only a notification from the EPA would trigger any additional action by an owner or operator. While the EPA would still rely on data from the third parties, the final rule incorporates new obligations on

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<sup>217</sup> 42 U.S.C. § 7604(b).

those third parties no longer trigger an obligation, instead any third-party notification must come through the EPA for evaluation and any obligation.

Comment: Commenter (2446-IPAA) states EPA needs to unequivocally state that the information/data submitted by third parties will not be the basis for enforcement action by state or federal regulators. Congress has spoken as to when third parties can engage in enforcement of the CAA and the process is set forth in Section 304 of the CAA. Noting in Section 111 of the CAA hints at utilizing third parties to provide regulators data to serve as the basis for enforcement of the CAA. Clarity on this issue from EPA would benefit all stakeholders.

Response II-14-255: EPA identifies the commenters' concern. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

Comment: In its request for comments, Commenter (2221-Texas Pipeline Association) notes EPA has touched upon a key issue in this context: whether data produced by third parties - some of whom might have an agenda - would be credible. The problem is that the data that would be submitted by untrained, unaccountable, and possibly biased, citizens in this context could often not be credible, or reliable, or a sufficient basis upon which to force a company to take action. Operation of emissions detection equipment, such as optical gas imaging monitoring equipment (FLIR cameras or similar thermal imaging technology), is a precise and technical exercise requiring training and operational expertise.<sup>218</sup> It is not a matter of simply pointing a camera at a tank battery and obtaining accurate measurements. Added to this are significant issues related to chain of custody, data integrity, and data preservation, as well as citizens' likely inability on occasion to determine ownership or operational custody of any given source of the emissions being reported, particularly at complex or multi-owner sites - which could lead to the submission of citizen-reports to the wrong company.

Commenter (2301-U.S. Chamber of Commerce) states that if any program concerning third-party notifiers were to move forward, EPA would need to specify that any such third-party notices will not constitute "credible evidence" under the CAA. "Credible evidence" refers to a collection of EPA regulations providing that both reference test and comparable non-reference test data may be used to prove or disprove violations of the CAA under the Title V, PSD/NSR, and other CAA programs.<sup>219</sup>

Response II-14-256: EPA recognizes these comments and in the final rule, we have developed a third-party notifier certification program to ensure organizations and individuals providing information to the Super Emitter Program are sufficiently qualified to do so. EPA has chosen to finalize the Super-Emitter Program as primarily a compliance assurance program. A notification

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<sup>218</sup> See, e.g., <https://www.asnt.org/MajorSiteSections/Standards/ASNTStandards.aspx> (requirements outlined by ANSI/ASNT CP-105 and CP-189 of the American Society for Non-Destructive Testing).

<sup>219</sup> See 62 Fed. Reg. 8314, 8316 (Feb. 24, 1997).

of a super-emitter event by EPA is not an allegation of a violation and is there to trigger an obligation to investigate by the owner or operator of an applicable oil and gas facility.

Comment: Commenter (2221-Texas Pipeline Association) opposes inclusion of a requirement for regulated parties to respond to emissions reports submitted by private third parties in Section 111 standards. While owners and operators do want to be alerted to large emission events from their sites, it is not appropriate to include in the context of Section 111 standards a set of rules that in effect deputizes third parties and provides them with the power to require responsive action by regulated companies. Congress delegated environmental investigative authority to EPA, not every individual citizen who can demonstrate the ability to use emissions detection equipment, and it is not our understanding that federal, state, and local governmental bodies currently lack the incentive, resources, or ability to conduct whatever emissions monitoring activities they deem to be required in any given situation. Governmental environmental agencies have proper equipment, training, subpoena power, investigatory authority, and financial resources to review and examine the operations of emission sources under their jurisdiction. Commenter (2221-Texas Pipeline Association) does not believe that it would be wise to inject into the currently existing regulatory and investigatory scheme a new layer of investigation that directly triggers company responses based on input from untrained and unaccountable "citizen enforcers" deputized by EPA via rulemaking. In addition, we are not aware of the legal basis upon which EPA might place this sort of regulatory authority in the hands of private third parties.

Commenter (2221-Texas Pipeline Association) argues it would be inappropriate for EPA under Section 111 to establish a system that would force a company to spend time and effort performing "root cause" analyses as well as other required activities in direct response to reports filed by untrained and unaccountable citizens operating sensitive and technical equipment at the fence line. The potential for tying up resources in response to the submission of repeated nuisance reports to companies is real. Moreover, as the TCEQ previously pointed out, EPA's proposal to allow citizens to create their own investigation program fails to include a framework for how individual states would work with EPA to resolve the alleged emission events purportedly identified by third parties. The proposed scheme not only has the potential to lead to significant safety issues at facilities (as well as issues involving site security) but it would also complicate an already complicated set of enforcement challenges. TCEQ, no doubt speaking from experience, also has expressed skepticism as to whether the third-party reports would be fair and unbiased, and concluded in prior comments that "[t]he proposed reporting pathway is unlikely to be successful, would only serve to further deplete state agency resources, and should be removed."<sup>220</sup>

Commenter (2221-Texas Pipeline Association) adds an additional problem with the program is that EPA proposes to make third-party reports available to the public online presumably via EPA's official website.<sup>221</sup> EPA states the agency "would generally not verify or authenticate the information in third-party reports prior to posting."<sup>222</sup> This would be unfair and ill-advised, as it

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<sup>220</sup> See TCEQ comments dated January 31, 2022 (EPA-HQ-OAR-2021-0317-0763) at 9.

<sup>221</sup> 87 Fed. Reg. 74750 (Dec. 6, 2022).

<sup>222</sup> Id.

would encourage the publication of potentially misleading information, both with respect to the nature of the event at issue and as to the proper identity of the owner or operator of the facility at issue. To be sure, a third-party would be free to publish any such report on its own website. But that is a far different matter from EPA publishing the report on its own official website. This would obviously provide the imprimatur of legitimacy and reliability on such a report, in effect an EPA endorsement of its contents. Given that the report could be partially or wholly inaccurate, and/or could misidentify the owner or operator of the facility at issue, EPA should avoid the appearance of giving any legitimacy to such a preliminary report.

Commenter (2221-Texas Pipeline Association) argues at a minimum, if EPA continues to contemplate such a program, then it should clearly set forth the legal basis upon which the program relies. Further, any such program must be one that contains strict requirements which ensure that reports filed by non-governmental personnel be submitted by one who has been properly trained and certified in the operation of the emissions detection equipment being used. Such reports should be filed with EPA, not directly with a company, and no response by the company (supposedly) involved should be required simply because a citizen has submitted a report; EPA triage of reports filed by third parties is essential and it should be EPA's responsibility to verify any data prior to publishing it on the agency's webpage. If EPA's assessment of the citizen-submitted data indicates that the data are valid and further action is required, then it should be up to EPA to contact the individual company or companies involved and to direct the companies to take whatever action EPA deems to be appropriate in the particular circumstances at issue. A general requirement whereby a particular company must undertake an extensive course of action (on pain of a noncompliance determination) simply because a citizen has decided to send the company a report supposedly detailing excess emissions would be unfair and unduly burdensome and would raise significant constitutional issues involving, inter alia, deprivation of due process and arbitrary enforcement.<sup>223</sup>

Commenter (2221-Texas Pipeline Association) states any rules that are implemented in this area should address the timeline for notification by third parties to companies. Reports to owner and operators must be completed and submitted in a timely manner to ensure emission reductions and to enable companies to determine the cause of the event at issue. It might not be possible to discover the cause of intermittent events that occurred weeks or months prior to discovery and reporting, because the event is no longer occurring and/or is too far in the past. For this sort of program to be effective in reducing emissions, companies should be notified within a very short time, and no longer than a week, when a large event is identified.

Response II-14-257: EPA recognizes the comment that companies should be notified in as short period of time as possible. We have revised the final rule to include a requirement that third parties must notify EPA within 15 days of a super-emitter detection. The 15-day time

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<sup>223</sup> See, e.g., *North Carolina Dept. of Revenue v. The Kimberley Rice Kaestner 1992 Family Trust*, 139 S.Ct. 2213, 2219 (2019) (due process clause centrally concerns the fundamental fairness of governmental activity); *Koender v. Lawson*, 461 U.S. 352, 361 (1983) (law encouraging arbitrary enforcement held unconstitutional); *Lassiter v. Dep't of Social Services*, 452 U.S. 18, 24-25 (1981) (constitutional guarantee of due process encompasses the requirement of fundamental fairness).

requirement is to allow sufficient time for a third-party to process super-emitter data and to identify the owner or operator of a site.

## 14.7 Compliance Assurance

Comment: Commenter (2433-EDF et al.) states EPA’s focus on compliance assurance fits particularly well with the goals of the program and with the problem of super emitters. Emission events exceeding 100 kg/hr indicate major problems at the site resulting from either non-compliance or serious operational issues. EPA has broad authority under section 114 to accept and use third-party monitoring data for purposes related to section 111, including ensuring compliance. Importantly, SERP does not and should not replace obligations on the part of owners and operators to reduce methane emissions from affected and designated facilities under the rules. Rather, SERP would serve as an additional backstop to ensure the unique problems posed by super emitters are timely addressed.

Response II-14-258: EPA acknowledges this comment and the program in the final rule has been structured as primarily a compliance assurance program. The program in the final rule, is a “backstop” and is designed to provide reliable emissions information outside of an owner or operators normal inspection schedule. When a super-emitter investigation is triggered and if an emission is identified from equipment subject to regulations as part of the super-emitter investigation, then the owner or operators are subject to any repair requirements from those regulations.

Comment: Commenter (2399-GPA Midstream Association) argues the Supplemental Proposed Rule cannot disguise its new proposed enforcement scheme as a “compliance assurance” measure. 87 Fed. Reg. at 74,753. Under this theory, the proposal asserts that allowing a private-party (or any enforcement agency) to unilaterally issue an order “to require corrective action to bring the facility back into compliance with the applicable standard or requirement” is merely “a backstop – an additional compliance assurance measure.” Id. The term “compliance assurance” is not found in the CAA or defined anywhere in 40 CFR, Part 60, let alone in any NSPS regulation. Thus, the Supplemental Proposed Rule’s attempt to “interpret” a new and unauthorized enforcement scheme is not an act of interpretation. And even if it was, the SERP would be inconsistent with the types of monitoring, testing, recordkeeping, and reporting programs that the affected facilities must satisfy that one would consider to be “compliance assurance” requirements. See, e.g., 40 CFR §§ 60.7 (notification and recordkeeping requirements by affected facilities for construction and operational changes, recordkeeping for unit startups, shutdowns, and malfunctions, installation of continuous monitoring devices); 60.8 (performance test requirements); 60.11 (“Compliance with standards and maintenance requirements” that includes performance testing, opacity observations, or continuous opacity monitoring); 60.13 (standards for continuous monitoring devices). Allowing third parties to issue unilateral compliance orders is not a “compliance assurance” measure and there is no evidence that Congress ever contemplated such a measure within the CAA.

Commenter (2399-GPA Midstream Association) states EPA cannot avoid the strictures of the CAA by designating a new (but temporary) “super emitters” source category. 87 Fed. Reg. at

74,752. Under this approach, a source would transition from being an affected facility under the Crude Oil and Natural Gas Facilities category to an affected facility under the newly created “Super emitter” category when one private party unilaterally claims another private party incurred a “super emitter event.” *Id.* Assuming the third-party’s information is correct, and the new “Super emitter” affected facility implements a corrective action, it would then presumably transition back to a Crude Oil and Natural Gas Facilities source. Or, put another way, a Super emitter designated facility will only come into existence where a Crude Oil and Natural Gas Facility source violates a Crude Oil and Natural Gas Sector Facility emission or work practice standard, and then cease to exist once the violation ends. That cannot square with the notion of a source category under CAA § 111

Moreover, Commenter (2399-GPA Midstream Association) adds that EPA’s approach is not well founded is confirmed by the proposed BSER for super emitters, which EPA proposes to define as the new super emitter source merely coming back into compliance with whatever pre-existing Crude Oil and Natural Gas Facilities emission standards or work practices that was purportedly violated. See *id.* (“the BSER for super emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super emitter emissions event”); see also *id.* at 74,753 (“Where one of these facilities is determined to be the cause of a super emitter emissions event, it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement”). Requiring action to bring a source back into compliance with the applicable rules is not a system of emission reduction – it is an enforcement action.

Commenter (2399-GPA Midstream Association) argues this unprecedented approach is also inconsistent with Section 111. The Administrator may create new source categories under 42 U.S.C. § 7411 (b)(1)(A) or sub-categories based on “classes, types, and sizes ... for the purpose of establishing such [performance] standards.” *Id.* § 7411(b)(2). Nothing in the statute allows for the Administrator to create a new source category consisting solely of facilities already included in another existing source category that are violating existing regulations. Nor could the Administrator create a sub-category of such facilities as the sub-category would not be created “for the purpose of establishing” any “standards.” The only BSER work practice standards the Supplemental Proposed Rule would impose is an order for a source to cure any alleged violation without so much as a notice of violation, much less any formal enforcement action and the accompanying statutory and due process protections.<sup>224</sup> The Supplemental Proposed Rule is not an attempt to interpret the meaning of some ambiguous statutory word or phrase; it is attempting to impermissibly create an entirely new type of enforcement program that sheds the CAA’s procedural mandates.

Commenter (2399-GPA Midstream Association) states the SERP deviates from EPA’s longstanding practice of designating specific equipment, such as tanks, turbines, or engines as

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<sup>224</sup> Nor is the Supplemental Proposed Rule able to characterize the SERP as merely “an additional work practice standard,” as work practice standards must “reflect [] the best technological system of continuous emission reduction.” 42 U.S.C. § 7411(h). An order to cure alleged regulatory violations is not a “technological system of continuous emission reduction.”

“affected facilities” under Section 111. Even fugitive emissions requirements are tied to specific equipment types, such as valves, connectors, or flanges. Here, however, the “affected facility” would be an entire site, containing various categories of affected facilities, and subject to what is effectively an arbitrarily selected bubble limit or site-wide cap of 100 kg/hour, applying to both planned and unplanned emissions.<sup>225</sup> Nothing in Section 111 authorizes EPA to use such an approach.

Response II-14-259: EPA recognizes the commenters concern and EPA has chosen not to finalize the Super-Emitter Program as part of BESR for a OOOOb “affected facility”. Instead, this program is designed to provide actionable and timely information to owner or operators when large emission events have been identified and evaluated by the EPA. In the final rule, EPA is providing the notifications to the owner or operator, and there is no requirement to investigate a super-emitter event until such time that EPA has provided a notification. The Super-Emitter Program only requires an owner or operator to investigate whether a super-emitter event has happened or ongoing, any additional obligation on part of the owner or operator is defined in the applicable regulation the equipment is subject to.

Comment: Commenter (2220-WDEQ) actively performs outreach to operators and ensures compliance issues are corrected in a timely manner. For example, the commenter’s compliance staffs currently complete approximately 1,000 Full Compliance Evaluations (FCEs) on oil and gas sites annually, with an additional 1,500 site visits or Partial Compliance Evaluations (PCEs) each year. Similarly, operators are already conducting their own compliance activities. Requiring compliance operators to respond to compliance observations from third-party entities (as described on pages 74747-74748 of the preamble) only complicates the compliance process. Furthermore, it could leave the commenter’s Compliance program in the dark about ongoing compliance issues that have been reported by a third-party.

Response II-14-260: EPA appreciates this comment and in the final rule, an owner or operators would not receive a notification from a third-party and instead a notification would come from the EPA. In the final rule, a super-emitter notification is not a suggestion of non-compliance and is intended to inform an owner or operator when a potential large-emission event has been identified at an applicable well site, centralized tank battery, or compressor station.

## **14.8 Other Program Issues**

Comment: Commenter (2408-Colorado Local Government Coalition) agrees with EPA that the proposed requirements for pneumatic controllers and inspection requirements for control devices and fugitive emissions components located at large well sites will help eliminate or reduce super emitters from these sources. Were EPA to adopt the commenter’s recommendation to require annual OGI inspections at small well sites and wellhead only sites, they would also agree with

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<sup>225</sup> The 100 kg/hour threshold is essentially an emissions limit, but EPA did not rely on any health-based or environmental drivers to establish it. The threshold appears to be based on current or pending satellite detection capabilities. See 87 Fed. Reg. at 74,749.

EPA that such requirements would help reduce super emitters from fugitive emissions components located at these facilities.

Response II-14-261: EPA thanks the commenters for their support of the super-emitter program. Please see Chapter 4: Fugitive Emissions from Well Sites, Centralized Production Facilities of the Response to Comment Document for responses addressing your comments on OGI inspection at small well sites and wellhead only sites.

Comment: Commenter (2326-AXPC) notes that in response to a super emitter notification, EPA's proposal would require an operator to determine if a natural gas-driven pneumatic controller or pump is venting to atmosphere continuously and requires repair of any controller or pump found venting to the atmosphere during idle periods, even where the pneumatic controller is not related to the super emitter event. This provision fails to recognize that in many circumstances, operators may be using continuous bleed pneumatic controllers (e.g., approved use under NSPS OOOOb or at EG OOOOc facilities prior to implementation of EG OOOOc and where approved use provided). Continuous bleed pneumatic controllers – by their very nature – vent (or bleed) to atmosphere during non-actuations. Thus, EPA's requirements regarding repair of pneumatic controllers should be limited to natural gas-driven pneumatic pumps and controllers subject to a NSPS OOOOb or EG OOOOc zero emissions standard.

Similarly, in response to a super emitter notification, commenter (2326-AXPC) states that EPA's proposed regulation requires an operator, upon finding an open thief hatch or open pressure relief valve, to "conduct [] a new engineering certification to ensure the controlled tank battery is designed and operated to achieve the no identifiable emissions standard." First, the engineering certification required by an operator with respect to storage vessels relates only to design and not to operation. Thus, no engineering certification will (or can) address future operations. Second, this requirement to conduct a new engineering certification is illogical. If a thief hatch or PRV is left open, that is most clearly not a design issue, but rather is related to operations. Thus, a new engineering certification will not in any way address the open thief hatch or pressure relief valve.

Commenter (2326-AXPC) recommends no investigative analysis should be required if the emissions are not associated with/emitting from an affected facility under NSPS OOOOb.

Response II-14-262: When an owner or operator responding to a super-emitter notification identifies an ongoing super-emitter event, and the cause of the super-emitter event, is equipment subject to regulation, that regulation would dictate the follow-up action.

Comment: Commenter (2394-Earthworks) has been conducting OGI fieldwork in Colorado for years and tracking the progress of an evolving oil and gas regulatory framework as new rules are adopted and implemented. Following the adoption of extensive new rules and regulations by the Colorado Oil and Gas Conservation Commission and Air Quality Control Commission in the last few years, Commenter (2394-Earthworks) list their field findings of 553 investigations of 383 oil and gas facilities in their comment.



Commenter (2394-Earthworks) summarizes their findings. Despite the adoption of stricter oil and gas regulations in Colorado, pollution from the industry is still pervasive and persistent. Pollution events are not simply isolated incidents but are often symptomatic of ongoing issues that we document repeatedly on separate surveys at the same facilities. Faced with these facilities that are a chronic source of emissions, our findings also illustrate that Colorado's enforcement system is ineffective at curbing this pollution and holding operators accountable for continued violations. In part, this is due to a lack of enforcement in general, as only six of the 111 facilities where we have documented evidence of pollution this year have been inspected by APCD staff. But even when APCD staff do inspect facilities and substantiate our evidence of noncompliance, there is a desire to work with operators to achieve compliance rather than enforce compliance through fines and penalties. Commenter (2394-Earthworks) provides an overview of the timeline of their findings at the Prospect Energy Krause MSSU Tank Battery in Larimer County in their comment.

Commenter (2394-Earthworks) states Colorado has adopted rules and regulations that are intended to protect health and the environment from oil and gas pollution. Yet, for two years we have documented OGI evidence of ongoing pollution from the same facility and despite two years of assurances by both the APCD and the operator, residents have suffered health impacts with no resolution in sight. For the residents who live near this facility and many more like them across Colorado it is clear that when put to the test, Colorado's enforcement system still struggles to functionally implement its nation-leading rule and regulations.

Response II-14-263: EPA recognizes the commenters concern and while we cannot directly address your concern, the Super-emitter program is being developed with transparency in mind, on the part of the third-party, the EPA, and the owner or operator. All notifications meeting the requirement in the final rule will be published online on the EPA's Super Emitter Portal - <http://www.epa.gov/super-emitter>.

#### ***14.8.1 Text Changes/Clarifications***

Comment: Commenter (2177-Ute Indian Tribe) suggests the following text correction in §60.5388c(e)(1):

"If the owner or operator has identified a demonstrable error in the notification, the report may instead include a statement of the demonstrable error as specified in ~~§60.5371b(a)(4)~~ §60.5388c.(a). (4)."

Response II-14-264: EPA appreciates the comment and we have made the suggested revision in the regulatory text.

Comment: Commenter (2177-Ute Indian Tribe) cites the following text from the proposed rule:

"Corrective action plans for additional analysis. If, upon completion of the root cause analysis and initial corrective actions such as those described in paragraph (c) of this section, you are notified of a super emitter emissions event from the same emission

source which was determined under paragraph (c) not to be an allowed venting of emissions as part of normal operations, including routine maintenance, or if the initial corrective actions will require more than 10 days to complete, you must develop a corrective action plan that describes the initial corrective action(s) completed to date, additional measures that you propose to employ to reduce or eliminate the super emitter emissions event, and a schedule for completion of these additional measures. You must submit the corrective action plan to the Administrator according to the schedule in paragraphs (d)(1) and (2) of this section.”

Commenter (2177-Ute Indian Tribe) recommends replacing "corrective action plans" with "notification". The purpose of this section is to fix, and prevent, these super emitter events. This can be accomplished without developing corrective action plans.

Response II-14-265: EPA appreciates this comment, we have chosen not to finalize the requirement for corrective action plans.

## Chapter 15. Other Emission Sources

### 15.1 Pigging Operations and Blowdown Activities

Comment: Commenter (2247-Ohio Environmental Protection Agency) states that it is unclear how pigging operations apply in NSPS and Emission Guidelines (EG) rules. The commenter notes that maintenance and inspections must be done on many of the pipelines associated with these rules. They explain the typical approach is to insert a “pig” in at a pig launcher, have it run through a section of pipe to either measure/inspect the pipe or to clean out liquids, and then have the pig removed at the end of the pipe. When the pig is inserted or removed from the pipeline, the pressure inside the pig receiver/launcher must be equalized with ambient pressure. In many situations, this pressurized gas is vented into the air resulting in air emissions and potential odors. Are pigging operations governed by these rules and, if so, how?

Commenter (2296-New Mexico Environment Department (NMED)) states that NMED included a comprehensive emission reduction and leak detection and repair (LDAR) strategy for pigging operations in the state rule Part 50. The note that individual pipeline pig launcher and receiver operations with a potential to emit (PTE)  $\geq 1$  tons per year (tpy) volatile organic compound (VOC) located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, are subject to the requirements of Part 50. The commenter encourages the EPA to adopt similar requirements in the proposed rule.

Commenter (2180-Pennsylvania Department of Environmental Protection (PADEP)) recommends that EPA establish requirements to reduce methane and VOC emissions from new and existing pigging operations. The commenter reports that they have required pigging operation to control VOC and methane emissions since 2018.

Commenter (2224-Zero Emission Vacuum and Compressor (ZEVAC)) believes that pigging operations and blowdown activities should be addressed in the rules. The commenter notes that the proposed rules reiterate the importance of advanced LDAR and the need to avoid flaring or venting gas at the wellhead but leave the practices of blowdowns (the depressurization of a natural gas pipeline to allow pipeline maintenance by opening a valve and allowing the gas to escape to the atmosphere) and flaring from downstream operations unregulated. The commenter believes that the EPA should issue further guidance and take action to eliminate or reduce the frequency, magnitude and severity of natural gas vented to the atmosphere from pipeline blowdowns and pigging operations.

Similarly, commenter (2410-California Office of the Attorney General (CA AG) *et al.*) encourages EPA to revisit potential regulatory options for “pigging operations,” which are maintenance activities performed on a daily, weekly, or monthly basis to prevent buildup of natural gas condensates in field gas gathering and transmission pipelines. The commenter explains that these operations require a facility to vent and blowdown any pressure in the line prior to removing the device known as a pipeline intervention gadget or “pig.” As demonstrated by regulations adopted by New Mexico, Colorado, and Pennsylvania, the commenter believes that cost effective and technically feasible best practices exist to reduce emissions from pigging

operations by reducing the flashing of hydrocarbons entrained in the liquids when the pigging unit is opened to remove the pig.

Commenter (2410-CA AG *et al.*) adds that New Mexico has adopted a comprehensive emission reduction and LDAR strategy for pigging operations located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations.<sup>1</sup> Colorado's rule covers pigging units at natural gas compressor stations, natural gas processing plants, and "stand alone pigging stations" that are not located within the boundaries of other regulated facilities. The commenter explains that Colorado relies upon a matrix of the size and pressure of the pigging pipeline to determine applicability of capture requirements. They continue by adding that Colorado requires all operating pressure over 500 pounds per square inch gauge (psig) to employ capture or control techniques and requires the capture of gas emitted during pigging. For smaller size and lower pressure pigging pipelines, Colorado determined that an emissions-based threshold was an appropriate approach. These thresholds are based on the location of the pigging unit, and depend on the type of location, such as whether the unit is in a disproportionately impacted community (more stringent thresholds apply to sources in disproportionately impacted communities). In Pennsylvania, the commenter provides that General Permit-5A regulates emissions from *Unconventional Natural Gas Well Site Operations and Remote Pigging Stations* and requires quarterly LDAR for sources at unconventional natural gas well sites or remote pigging stations.<sup>2</sup> Given these state regulatory programs, the commenter requests that EPA consider similar requirements in future rulemakings.

Other commenters (2211-Lambda Energy Resources LLC (Lambda), 2221-Texas Pipeline Association (TPA)) support EPA's decision to not set standards for pigging.

Commenter (2211-Lambda) urges EPA to avoid new regulations to pipeline pigging operations, which they report is a necessary and frequent safety testing practice within their gathering operations. The commenter explains that most pigging operations result in only a minute amount of hydrocarbons (est. 1-20 standard cubic feet (scf) per event) being lost from pig launchers or receivers. Because of the minimal amount of venting (est. 10 thousand cubic feet (mcf) per year for all events) associated with these operations, the commenter states that the need to capture gas during pigging is overly burdensome, not cost effective, and would disincentivize operators to conduct safety procedures. Alternatively, they add that where it is necessary to evacuate a line of product for pigging, they flare (and report under Subpart W) the small amount of displaced gas.

Commenter (2221-TPA) provides that there is currently insufficient data on pigging operations to adequately inform rulemaking in this area. The commenter contends that it is evident that EPA lacks sufficient information regarding the number of sources, emissions resulting from pigging, and similar basic information that traditionally would be input into a regulatory cost-benefit analysis and necessary to make a best system of emission reduction (BSER) determination. The commenter notes that it is true that EPA collects some data related to pig launchers and receivers through the GHG reporting program (GHGRP), however this information is limited to relatively large operations (above 50 cubic feet actual volume) and the emissions data that is captured reflects aggregate emissions data from multiple sources across an entire basin in the context of gathering and boosting. The commenter suggests that such macro-level, imprecise, and limited

data cannot reliably inform a useful cost-benefit analysis. At a minimum, according to the commenter, any rulemaking in this area should be preceded by an information collection request (ICR) aimed at gathering data that could allow EPA to assess the level of emissions fully and systemically at issue as well as the costs of imposing regulations in this area.

In addition, the commenter (2221-TPA) recommends that, should EPA ever intend to revisit this subject in the future, they would urge EPA to avoid overly prescriptive requirements in any standards it might propose regarding pigging operations. In the area of pigging operations, the commenter explains that there is no one-size-fits-all approach; the most effective, efficient, and environmentally sound procedure will vary greatly from site to site and is highly dependent on each individual site's particular characteristics. If any standard were ever implemented, they state that it should be one that sets a goal and leaves it to individual regulated entities as to how that goal is to be achieved. The commenter adds that overly prescriptive standards are inadvisable for the additional reason that reduction of emissions in pigging operations is an emerging field with new technology being developed on an ongoing basis. According to the commenter, a top-down prescriptive approach, *i.e.*, a rule that does not just say what the goal is but goes on to dictate how that goal must be achieved, would run the risk of stifling, if not altogether killing, the innovation that is currently underway as companies and consultants develop innovative and varied ways to reduce pigging emissions. The commenter suggests that the EPA should allow such emerging innovation to flourish.

In addition, the commenter (2221-TPA) recommends that the EPA should always bear in mind that the scope and level of emissions varies greatly from one pigging operation to the next. In many cases the emissions from a launcher or receiver can be de minimis, while a more extensive operation at an upstream location could result in higher emissions. For this reason, the commenter believes it would be reasonable for any future new standards to contain applicability thresholds expressed in emissions amounts, measured at each individual receiver or launcher, to exclude those sources and operations that are not resulting in significant emissions amounts. In keeping with other provisions in the NSPS, the state that an applicability threshold is a reasonable and fair way to avoid undue burden on small sources and further to avoid imposing requirements that do not meet a reasonable cost vs. environmental benefit standard. The commenter adds that an applicability threshold would have the additional benefit of incentivizing owners and operators to find ways to reduce emissions to keep emissions below threshold applicability levels.

Additionally, commenter (2221-TPA) supports EPA's proposal not to impose new requirements on pipeline blowdowns under the NSPS or any existing source standards. They contend that pipeline blowdowns should not be regulated as a source category. They explain that a blowdown is not traditionally considered to be an identifiable source of emissions, but rather an action taken for safety and/or operational reasons in the field. Moreover, they add that source categories in the NSPS context have traditionally been limited to structures that serve as emission sources. Pipelines, which are generally located underground and do not have normal operating emissions, do not fit that description, which they state may explain why they heretofore been subject to NSPS regulation as a separate source category.

The commenter (2221-TPA) contends that regulations in this area would present unduly complex compliance issues. According to the commenter, pipeline blowdown can affect numerous different pipeline segments, some that might be considered new or modified under the rules, and some that might be considered existing. The commenter expresses that this would raise compliance questions of whether the pipeline affected by the blowdown activity was governed by standards applicable to new sources, existing sources, or both. They add that this could be an extremely difficult question to answer in practice, given that pipelines can run for hundreds or thousands of miles and can be modified or replaced in numerous shorter segments within the overall pipeline length. In addition, there are many types of pipelines outside of the oil and natural gas sector, and regulating pipeline emissions, which is essentially what this emission category would be, would require a broader look at emissions from pipelines prior to proposing a rule.

Commenter (2224-ZEVAC) provides that existing technology allows operators to construct and maintain piping without the use of blowdowns or flaring. The commenter suggests that pigging practices be examined because of the risk that harmful VOCs are also released into the air in addition to methane. The commenter notes that they use portable compression to bring down gas pressure on an isolated pipeline segment and redirect the gas downstream of the isolated segment. The use of their technology, according to the commenter, eliminates the direct flow of methane into the atmosphere, improves safety and reduces operating costs. The commenter suggests that EPA should establish guidance and best practices that would require operators to evaluate pipeline blowdown mitigation options, compile project data for blowdowns and gas saved, and calculate and report their methane emissions reductions.<sup>1</sup> The commenter states that the proposed rules add stricter requirements for monitoring, detecting, and repairing *unintentional* leaks, yet they do not encourage the elimination of *intentional* blowdowns and flaring. On a dollar per emission basis, the commenter reports that the prevention of intentional emissions is more effective and efficient than searching for and repairing leaks.<sup>2</sup> The commenter adds that reducing venting and flaring will help bring more gas to market and could offer cost relief to in times of high demand and prices. The commenter contends that regulations should incent the use of existing technology to prevent intentional release of methane and VOCs into the atmosphere through intentional pigging and blowdown operations.

Similarly, the commenter (2224-ZEVAC) provides that the proposed rules revise the requirements for gas flaring at wells and require that available gas must be rerouted for beneficial uses unless an operator can show that all beneficial uses outlined in the supplemental proposal are unsafe or infeasible. They note that technology exists to reroute gas that would be vented or flared for beneficial use in downstream operations and the EPA should promulgate similar guidance to encourage the beneficial use of gas in the entirety of the natural gas value chain. The commenter states that the EPA has recognized their technology as a recommended

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<sup>1</sup> For example, the commenter states that the EPA has encouraged the capture and use of gas normally vented from pipeline pigging operations using recovery compressors. See Partner Reported Opportunities (PROs) for Reducing Methane Emissions, Fact Sheet No. 505, available at: <https://www.epa.gov/sites/default/files/2016-06/documents/pigging.pdf> (last retrieved February 13, 2023); see also <https://www.iea.org/reports/flaring-emissions> (last retrieved February 13, 2023).

<sup>2</sup> See e.g., [https://www.socalgas.com/sites/default/files/2020-09/SCG\\_SB1371\\_Amended\\_2020\\_Compliance\\_Plan\\_Sept\\_2020.pdf](https://www.socalgas.com/sites/default/files/2020-09/SCG_SB1371_Amended_2020_Compliance_Plan_Sept_2020.pdf) at p. 5 (noting cost of leak survey at \$26/MCF versus cost of blowdown reduction at \$19/MCF) (last retrieved February 13, 2023).

technology to reduce methane emissions and the proposed rules should encourage operators to deploy existing techniques that reduce emissions and improve safety and save costs.

Response II-15-1: In the November 2021 Proposal, EPA solicited comment and data to assist the Agency in evaluating the potential for developing emissions standards for additional emission sources, including pigging operations and related blowdown activities. EPA did not propose emissions standards for pigging operations and related blowdown activities in the December 2022 Supplemental Proposal; therefore, this final action does not include emissions standards for these emission sources. We may consider regulation through a future action, including in the next 8-year review of the New Source Performance Standards (NSPS). The comment summaries are provided below for reference, but substantive responses are not provided because no emissions standards have been proposed for this emissions source.

## 15.2 Truck Loading

Comment: Commenter (2296-NMED) provides that they included emission control requirements for truck loading operations in state rule Part 50. The commenter encourages the EPA to adopt similar requirements in the proposed supplemental rule.

Response II-15-2: In the November 2021 Proposal, EPA solicited comment and data to assist the Agency in evaluating the potential for developing emissions standards for additional emission sources, including tank truck loading. EPA did not propose emissions standards for tank truck loading in the December 2022 Supplemental Proposal; therefore, this final action does not include emissions standards for these emission sources. We may consider regulation through a future action, including in the next 8-year review of the NSPS. The comment summaries are provided above for reference but substantive responses are not provided because no emissions standards have been proposed for these emissions sources.

## 15.3 Other Emission Sources

Comment: Commenter (2180-PADEP) recommends that EPA add the following sources to the existing proposed regulatory requirements:

- *Glycol Dehydration Units:* EPA should establish requirements to reduce methane and VOC emissions by 95 percent or more from new and existing glycol dehydration unit still vents if their potential or actual emissions exceed 200 tpy of methane or 2.7 tpy of VOC. The commenter reports that it has required 95 percent VOC control on glycol dehydration units since 2018.
- *Threshold for Multiple Sources Controlled by a Single Device:* EPA should require multiple sources that can be controlled by a single emission control device to comply with a 2.7 tpy VOC emission threshold. For example, if EPA were to adopt the 2.7 tpy VOC threshold for each storage vessel, glycol dehydration unit, and pneumatic pump individually, these singular sources could emit less VOC emissions than the current threshold and remain uncontrolled. However, if their combined emissions were considered, they would emit nearly 8 tpy of VOC without control, whereas it is cost effective to control VOC emissions at 2.7 tpy. The commenter recommends that EPA

establish a 2.7 tpy VOC emission threshold and 20 tpy methane emission threshold for multiple sources that can be controlled by a single control device.

Response II-15-3: These comments are asking EPA to regulate additional sources that EPA did not propose standards or solicit comment. Therefore, this final action does not include emissions standards for these emission sources. The comment summaries are provided above for reference but substantive responses are not provided because no emissions standards have been proposed for these emissions sources.



## Chapter 16. Covers and Closed Vent Systems

### 16.1 Applicability

Comment: Commenter (2399-GPA Midstream Association) expresses that new source performance standards (NSPS) under subpart VVa have never included welded seams as fugitive emission components. They explained the following reasons: Once welded, these seams must meet all pressure and leak tests associated with the original pipe and are, in fact, structurally similar to the pipe. Further, they state that inspecting them presents practical difficulties as welded sections are not tracked on piping and instrumentation diagrams or any other inventory. The commenter contends that owners and operators would have to undertake an unusually time-consuming and burdensome survey of all pipe welds in the facility and that this should not be necessary. The commenter maintains that the December 2022 Supplemental Proposal provides no rationale for requiring weld inspections, such as claims that these welds leak in any way. Absent a rational basis for imposing such a requirement, the commenter recommends EPA exclude welded pipe seams from audio, visual, and olfactory (AVO) inspections.

Response II-16-1: EPA is not excluding welded pipe seams on closed vent systems from AVO inspections. The requirement to conduct visual or AVO inspections of welded seams on closed vent systems has been required for this source category since NSPS OOOO was finalized in 2012. Similar requirements were finalized in 2016 for NSPS OOOOa. EPA is not aware through implementation of these standards that conducting AVO inspections on welded joints between two pieces of hard-piping has caused undue burden to the regulated community.

Further, contrary to the commenter's assertion, while welded seams are excluded from the definition of "connector" (and hence connector monitoring) under NSPS VVa, welded seams on closed vent systems under NSPS VVa must be monitored using AVO, as welded seams may be found on hard-piping, where two pieces of hard-piping are joined together. See 40 CFR 60.482-10(f)(1)(ii).

### 16.2 Clarification of What Constitutes a "Bypass"

Comment: Commenter (2403-Petroleum Alliance of Oklahoma (PAO)) notes that EPA states that if the closed vent system (CVS) is equipped with a bypass, the bypass must include a flow monitor and sound an alarm to alert personnel that a bypass is being diverted to the atmosphere or it must be equipped with a car-seal or lock-and-key configuration to ensure the valve remains in a non-diverting position. The commenter considers it to be unclear what EPA means by "bypass." The commenter assumes that open tank hatches are not considered a bypass. The commenter requests that EPA clarify that a bypass does not include an open tank hatch.

Response II-16-2: While improper design or operation of a thief hatch may result in a bypass of emissions from the control device to the atmosphere, EPA confirms that a thief hatch is not a bypass device subject to flow monitoring and alarms or to a car-seal or lock-and-key configuration. However, EPA notes that thief hatches should not be left in the open position. A thief hatch that is left open on a controlled storage vessel is considered improper operation of the cover, as the cover is required to form an impermeable barrier over the entire surface of the

liquid and each opening is required to be closed and sealed except in limited circumstances (*e.g.*, sampling the material in the storage vessel, adding material to the storage vessel).

### 16.3 “No Identifiable Emissions” Standard

Comment: Commenters (2202-Texas Oil & Gas Association (TXOGA), 2227-Western Energy Alliance (WEA), 2248-North Dakota Petroleum Council (NDPC), 2326-American Exploration and Production Council (AXPC), 2391-Chesapeake Energy Corporation (CEC), 2403-PAO, 2428-American Petroleum Institute (API)) ask EPA to reconsider the adoption of a no identifiable emissions standard as a numerical emission limit. They argue that it would be burdensome and contrary to historic EPA practice. Commenters (2202-TXOGA, 2227-WEA, 2248-NDPC, 2326-AXPC, 2391-CEC, 2428-API) note that all equipment leaks, and should not be considered violations.

Commenter (2202-TXOGA) states that the December 2022 Supplemental Proposal specifically acknowledged that EPA had earlier “proposed that covers and CVS must be designed and operated with no detectable emissions (NDE).”<sup>1</sup> The commenter states that EPA further noted that it had proposed that, “where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions from the covers and CVS through OGI [optical gas imaging] or EPA Method 21 monitoring conducted during the fugitive emissions survey.”<sup>2</sup> The Agency, according to the commenter, then reiterated its earlier problematic statement, that “[w]here emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation,” and that “corrective actions to complete all necessary repairs as soon as practicable would be required.”<sup>3</sup>

The commenter (2202-TXOGA) asserts that the proposal should not be adopted. First, the commenter provides that the assertion that EPA has always considered the “no detectable emissions” standard to constitute an emissions standard and not a work practice standard, and that the detection of emissions, in and of itself gives rise to a “potential violation” of that supposed emissions standard, is not supported by the record, and it rests on a shaky historical foundation. The commenter notes that in analogous regulatory settings involving CVSs, the detection of emissions above a given threshold would in turn trigger an obligation on the part of the owner/operator to undertake a repair within a specified time period. It was the failure to effectuate such repairs that constituted the violation, not the mere identification of emissions themselves.<sup>4</sup> The commenter is unaware of EPA having ever previously taken the position, in the record of such a rulemaking, that the detection of emissions upon inspection would, in and of

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<sup>1</sup> 87 Fed. Reg. at 74,804.

<sup>2</sup> *Id.*

<sup>3</sup> *Id.*

<sup>4</sup> See, *e.g.*, 40 C.F.R. Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks. Specifically, under 40 C.F.R. §63.172 (*i.e.*, setting forth standards for close vent systems and control devices), paragraph (h) provides that “[l]eaks, as indicated by an instrument reading greater than 500 parts per million above background or by visual inspections, shall be repaired as soon as practicable,” with a “first attempt at repair” being made “no later than 5 calendar days after the leak is detected,” and the repairs needing to be completed “no later than 15 calendar days after the leak is detected.” Even then, under certain conditions (*i.e.*, as specified in paragraph (i)), even those deadlines for undertaking and completing repairs could be delayed.

itself, constitute a violation. According to the commenter, for EPA to purport now to be saying that its own prior use of the terminology “no detectable emissions” had somehow led the regulated community astray, that the regulated community had all these years misperceived the NDE standard to provide a “grace period,” that no such “grace period” was never intended but was but a figment of the regulated community’s collective imagination, and that it was now necessary, for the purpose of “clarification,” for the Agency to adopt new terminology – *i.e.*, the “no identifiable emissions” standard – is, with respect, a doubtful recollection on the Agency’s part of its own decades-long practice and prior understanding.

Second, the commenter (2202-TXOGA) states that it is a reality of engineering that a “zero-emissions” standard can never be perfectly achieved. According to the commenter, even the best designed equipment, designed to meet an NDE standard, will incur leaks from time to time. Put simply, a zero-emissions standard is not achievable. The commenter states that EPA cannot point to anything in the record of this rulemaking that indicates that there is any system capable of achieving such a standard is adequately demonstrated. For this reason, the commenter considers what is purported to be proposed to be inconsistent with the Clean Air Act (CAA) section 111(a)’s plain terms.

Commenters (2227-WEA, 2326-AXPC) provide that the no identifiable emission standard effectively establishes a “zero” numerical standard to covers and CVS, which is practically unachievable and therefore, cannot constitute best system of emission reduction (BSER). In addition, commenter (2227-WEA) notes that it would strongly discourage voluntary detection campaigns of operators from the use of more sensitive detection technologies. The commenter maintains that such a standard is unachievable because all equipment, regardless of design, will eventually leak as a part of normal operation. The commenter recommends that leaks on covers and CVSs be treated no differently than those on other types of equipment and be subject to the leak detection and repair (LDAR) work practice standard, instead of an unachievable numerical emission limitation. The commenter argues that simple malfunctions and equipment failures should not be treated the same way as a violation.

Similarly, commenter (2248-NDPC) requests EPA reconsider its approach to regulate fugitive emissions from covers and CVSs differently than other fugitive emissions from nearby components covered under the LDAR provisions. The commenter notes that since before NSPS OOOOa, the oil and natural gas industry has been doing optical gas imaging (OGI) surveys and has learned much about fugitive emission leaks, their causes, and potential mitigation. The commenter states that the no identifiable emissions standard is basically a zero-emission standard and is unrealistic, unattainable, and overly burdensome when you consider the components in question are in proximity to each other and are exposed to the same wear and tear (mostly by exposure to extreme weather conditions and hydrocarbons). The commenter maintains that an increase in the frequency of inspections should be enough to satisfy EPA’s concerns.

Furthermore, commenter (2248-NDPC) indicates that the no identifiable emissions standard requirement seems unnecessarily burdensome. The commenter points out that the proposed rule already has design and LDAR requirements and that the components that make up the covers and CVS are exposed to the elements just like all the other components included in the LDAR

requirements. According to the commenter, why a leak in the CVS pipe should be considered a violation, and a leak in a gas pipeline ten feet away would not, does not make any sense.

The commenter (2248-NDPC) notes that leaks at these components may have nothing to do with inadequate design or operation. The commenter explains that pressure and vacuum relief devices are present for safety reasons to prevent the tank from over-pressurization as well as under pressure (*i.e.*, vacuum). The commenter notes that temperatures in North Dakota can vary as much as 60+ °F in a 24-hour period. This temperature change causes the content of the tanks to expand and shrink. Without these control devices, the tanks would fail. The vacuum side for the pressure relief device is especially susceptible to sucking in dust and sometimes even bugs that prevent the device from sealing. The commenter provides that these are all taken care of as part of the LDAR program. Finally, the commenter notes that design issues, if any, will show up as repeat offenders in the LDAR program and will be corrected as part of that program.

Commenter (2391-CEC) states that CVSs often have mechanical components such as fittings and seals, that are prone to some de minimis level of leaking despite compliance with all other requirements. The commenter notes that EPA recognizes this reality by proposing annual inspections for “defects that could result in air emissions” including “liquid leaks” and establishing a leak repair schedule.<sup>5</sup> Because very small leaks are unavoidable and no LDAR program—no matter how robust—can prevent all leaks 100 percent of the time, the commenter maintains that operators will not be able to comply with the proposed “no identifiable emissions” standard.

Additionally, the commenter (2391-CEC) notes that the term “no identifiable emissions” is used for the first time in the December 2022 Supplemental Proposal, where EPA explains that it is meant to be equivalent to the term “NDE” but accounts for the use of OGI, which is very effective at identifying leaks but does not measure methane concentrations:

NDE is a term closely linked with EPA Method 21 and is defined based on an instrument reading in units of ppmv. Because the EPA is proposing compliance inspections for covers and CVS using optical gas imaging and AVO, no instrument reading in ppmv is available. Therefore, the EPA is proposing the design and operational standard as an emissions limit of no identifiable emissions, which is more appropriate for the methods of detection required.<sup>6</sup>

The commenter (2391-CEC) contends that there is a major difference between the terms NDE and no identifiable emissions (NIE) for operators. According to the commenter, NDE recognizes that there are unavoidable de minimis leaks in even the best designed and managed operations. Thus, small leaks that cause concentrations of less than 500 parts per million by volume (ppmv) meet the NDE standard. On the other hand, depending on the conditions, OGI often detects leaks well below this threshold, and any such leaks would be a violation of the NIE standard. The commenter contends that even though EPA recognizes that OGI is more effective at identifying leaks quickly and efficiently than EPA Method 21, the imposition of a NIE standard is a

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<sup>5</sup> 87 Fed. Reg. at 74806; see also proposed 40 C.F.R. §§60.5416b(a), (b)(4); 60.5416c(a), (b)(4).

<sup>6</sup> 87 Fed. Reg. at 74805.

disincentive for operators to use OGI. The commenter states this is an appropriate design standard but an unachievable operational standard.

Furthermore, the commenter (2391-CEC) suggests that the NIE standard leaves owners and operators exposed to enforcement, despite complying with all regulatory inspection requirements. With no means of distinguishing between a minimal leak on a small mechanical component (such as gasket or fitting) from a significant over-pressure event, the commenter states that there is no bright line for EPA or state inspectors to use when determining whether a violation has occurred or in establishing an appropriate penalty. Therefore, the commenter recommends that EPA remove the proposed “no identifiable emissions” standard or state in the regulations that, despite detecting de minimis emissions on a given day, an operator is not in violation of the regulations if all emissions identified via OGI inspections were corrected within the prescribed time frame.

Commenter (2403-PAO) contends that a zero-emission standard is not feasible or realistic for equipment located outside, subject to harsh conditions and undergoing continuous wear and tear of operations. The commenter provides that there is the potential for the intrusion of foreign objects preventing re-seating of seal surfaces, *e.g.*, dirt or ice interfering with the sealing surfaces of tank hatches, particularly on vacuum seals. According to the commenter, emissions from such a scenario is not an indication of inadequate CVS design. The commenter adds that when wells are shut-in, tank emissions are reduced to breathing emissions which are very minimal and often there is not enough flow to the flare or control device to prevent flashback and an explosion, which create greater environmental and safety impacts than the minimal breathing emissions. After multiple tank fires in North Dakota, the North Dakota Department of Environmental Quality (NDEQ) acknowledged this risk and issued guidance that allows for tank vapor flares and control devices to be bypassed when a well is shut in to minimize the risk. In these cases, the hatches may need to be left open to relieve breathing pressure due to temperature fluctuations throughout the day. Further, the commenter states that it is common to isolate a tank that needs repair, empty the tank, and leave the hatch open to vent vapors to allow for repair for several days. Finally, the commenter notes that if vapor recovery and flare are not required at a facility, then tank emissions are understood to be vented to atmosphere in their entirety, regardless of whether the emissions occur from tank vents, openings, conservation vent valves, pressure relief valves, or a thief hatch. The commenter requests EPA remove the no identifiable emission standard and include CVS under the LDAR monitoring program. The commenter also requests that EPA allow exceptions for tank hatches, open vent lines, and other similar operational situations.

Commenter (2428-API) notes that as with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

According to the commenter (2428-API) EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. The commenter contends that EPA has presented no reason in the proposal to depart from its historical approach regarding

fugitive emissions from CVSs. The commenter states EPA must make it clear that a CVS remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

To this end, the commenter (2428-API) maintains that a “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. The commenter explains that even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and CVS components is practically unachievable because some leaks will happen in the normal course of operations (*e.g.*, typical fugitive leaks) and some develop due to causes beyond an operator’s control. The commenter considers that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or CVS should also only be subject to the standard work practice standard. According to the commenter, there is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or CVS.

Additionally, the commenter (2428-API) notes that a leak may develop due to malfunctions or a foreign object (*e.g.*, sand or dust), both of which are not reasonably within the control of the operator. The commenter adds that such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. The commenter recognizes the possibility of improperly operating a cover or CVS (*e.g.*, forgetting to close a thief hatch), but asks that EPA clearly differentiate these types of leaks from those described above. For these reasons, the commenter considers EPA’s application of the standard as a numerical emission limitation to not only be unachievable but also have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. The commenter requests that EPA encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or CVS.

Lastly, commenter (2428-API) states that CAA section 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (*i.e.*, numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” The commenter contends that this is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the CVS is installed. Rather, the proposed NIE standard applies to the CVS itself. In this case, the commenter maintains that it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the CVS to which the NIE standard applies would have to be enclosed within another CVS or similar permanent total enclosure for the regulated emissions to be captured for subsequent control or venting. According to the commenter, requiring such a system would be inordinately costly, highly impracticable, and likely impossible. The commenter points out that this is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. The commenter concludes that the NIE standard cannot be effectively construed as a zero-emissions standard, as

EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

Response II-16-3: See discussion in section XI.K. of the preamble to the final rule which details EPA’s final standards for covers and closed vent systems, including “no identifiable emissions.”

## **16.4 Leak Repair Timeline**

Comment: Commenters (2403-PAO, 2428-API) recommend EPA extend the first repair attempt timeline. Commenter (2403-PAO) considers 5 days for a first attempt of repair to be infeasible for technical and safety considerations. Commenter (2428-API) recommends an extension to streamline requirements across fugitive emissions requirements in consideration of the broader reach under NSPS OOOOb and EG OOOOc than under NSPS OOOO and OOOOa.

Commenter (2403-PAO) states that EPA is proposing that any leak detected would be subject to repair, with a first attempt at repair at 5 days and final repair within 30 days. The commenter notes that requiring the first attempt at repair within 5 days may be too short a time frame to obtain equipment or service companies to make the necessary repairs. They add that, if alternative monitoring technologies (*e.g.*, flyovers) are being used, it may take time to download information, review reports, and then prioritize emission findings. The commenter also states that a short repair time frame may disincentivize the use of alternative technologies. The commenter provides that any hydrogen sulfide at the site may also complicate being able to meet the first attempt of repairs within 5 days requirement. The commenter requests EPA change the first attempt at repair from 5 days to 10 business days.

Commenter (2428-API) reports that the 5-day timeline to implement the first repair attempt requirement will apply to significantly more sites under NSPS OOOOb and EG OOOOc than under NSPS OOOO and OOOOa. The commenter considers this requirement to be impractical for some sites that have access limitations such as those on leased farmland. While the commenter recognizes the historic importance and priority of repairing leaks on covers and CVSs, they believe that a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and CVSs will increase significantly under NSPS OOOOb and EG OOOOc requirements. The commenter also notes that a different first repair attempt timeline could have the added benefit of making repair timelines consistent between fugitive emissions components and covers and CVSs, thus streamlining compliance for operators.

Response II-16-4: EPA is not providing for a longer first attempt at repair timeline, as the repair is a corrective action which must be undertaken as quickly as possible to ensure and demonstrate the associated/designated facility is in compliance with the 95 percent reduction standard. See also the discussion in section XI.K. of the preamble to the final rule which details EPA’s final standards for covers and closed vent systems, including “no identifiable emissions.”

Additionally, EPA disagrees that the first attempt at repair timeline disincentivizes the use of advanced methane detection technologies or that the timeframe conflicts with data processing of reports from periodic screening events. In 40 CFR 60.5398b and 5398c, EPA lays out a timeframe for conducting certain activities associated with periodic screening events. First, an

owner or operator must receive the results of the periodic screening event no later than 5 calendar days after the event takes place. Second, if there is a confirmed detection by the advanced methane detection technology, the owner or operator must conduct a ground-based inspection to determine the cause of the detection. For a cover or closed vent system, the first attempt at repair deadline is based on the date of the ground-based inspection, not the screening event. Therefore, this timeframe for first attempt at repair is the same, regardless of whether an owner or operator uses advanced methane detection technologies, OGI, or EPA Method 21, and as such, there is no disincentive created.

## 16.5 Monitoring Frequency

Comment: Commenter (2428-API) provides that CVSs have historically been subject only to initial and annual inspections due to their low leak rates. The commenter notes that CVSs rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in a CVS do not experience the same wear and tear and potential for leaks as moving parts that generate friction. The commenter contends that, while OGI does not have the same proximity challenges as EPA Method 21, more frequent monitoring of CVSs would still be impractical for both methods as parts of CVSs are considered difficult to monitor. The commenter maintains that more frequent inspections for CVSs at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, the commenter recommends that for CVSs, hard piping be subject to an initial EPA Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial EPA Method 21 or OGI inspection and annual EPA Method 21 or OGI inspections. The commenter asserts that, if EPA decides to finalize the increased monitoring frequency for CVSs, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Response II-16-5: In this final rule, EPA is finalizing that inspections of the CVS must occur at the same frequency as inspections under the fugitives' program (or for CVS located at onshore natural gas processing plants, at the same frequency as the required monitoring). As explained in the December 2022 Supplemental Proposal, routine inspections are necessary to ensure compliance with the no identifiable emissions design and operational standards. It is most efficient and cost effective to monitor the CVS at the same frequency and according the same methodology for other fugitive or equipment leak components, since monitoring personnel will already be on-site.

While the inspection frequency for CVS in NSPS OOOOb and EG OOOOc is greater than for CVS in other sectors, EPA notes that in addition to EPA Method 21, we are allowing OGI and advanced methane detection technologies to be used for conducting continuous compliance monitoring of CVS in this rulemaking, unlike in other sectors. This allows the CVS to be monitored more quickly, and as such, it is not expected that an increase in the frequency of inspection will increase the burden of inspections.



## **16.6 Regulatory Text Citation**

Comment: Commenter (2428-API) suggests that the following citation be checked for correct cross referencing: 40 CFR 60.5420b(c)(12).

Response II-16-6: The cross-referencing has been corrected in the final rule.

## Chapter 17. Control Devices

### 17.1 All Combustion Control Devices

#### 17.1.1 Continuous Burning Pilot

Comment: Commenters (2298-Pioneer, 2326-AXPC, 2428-API) suggests that EPA allow use of an automatic ignition device in lieu of a continuous burning pilot.

Commenter (2428-API) states that a continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, the commenter explains, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device, state both commenters. Similarly, burning sour gas generates additional emissions including SO<sub>2</sub> and potentially uncombusted H<sub>2</sub>S, states. The commenter explains that some state rules, such as New Mexico<sup>1</sup> and Texas<sup>2</sup>, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame and suggests the following edit to the regulatory text (suggested additions are underlined):

40 CFR 60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame or automatic ignition system.

Commenter (2218-TCEQ) supports the continued use of 40 CFR 60.18 requirements and monitoring to demonstrate 98 percent destruction efficiency for flares and vendor information for other control devices. The commenter notes that their own authorization mechanisms for flares closely match 40 CFR 60.18 requirements and allow for the use of an automatic pilot. The commenter recommends that the EPA allow the use of an automatic pilot as an option for non-pressure-assisted flares. The commenter adds that many remote sites only have field gas as an option to use in a continuous pilot; field gas may have a high concentration of hydrogen sulfide, so using a continuous pilot in these situations may lead to increased emissions of hydrogen sulfide and sulfur dioxide, warns the commenter. In addition, the commenter provides that the remoteness of and lack of electricity for some sites may present logistical barriers complicating or preventing the implementation of continuous monitoring.

Response II-17-1: As we explained in the Response to Public Comments documents for the August 23, 2011 proposed rule<sup>3</sup> and September 18, 2015 proposed rule<sup>4</sup>, we maintain our position that without a continuous pilot flame, there may be periods of uncontrolled emissions. We also note that the General Provisions for 40 CFR part 60 rules require flares to be operated with a flame present at all times in §60.18(b)(2). There is not sufficient data currently to suggest that electronic ignition systems on combustion devices are capable of continuously supplying a constant source of ignition adequate to keep a flame present on a continuous basis, especially considering the fact that unlit

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<sup>1</sup> 0.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC.

<sup>2</sup> 30 TAC §106.492(1)(B).

<sup>3</sup> See EPA-HQ-OAR-2010-0505-4546, page 307.

<sup>4</sup> See EPA-HQ-OAR-2010-0505-7632, page 11-190.

flares are a major issue within the oil and gas sector. EPA also does not have sufficient information on the degradation of electronic ignition systems or how to ensure these systems maintain functionality over time. Additionally, operating a flare with a continuously lit pilot adds an additional degree of flame stability to the flare itself.

We note that the final rule specifies the use of a continuous burning pilot flame. Electronic igniters do not meet this provision. Although an electronic ignition device does not qualify as a continuous burning pilot flame, it may be used, for example, as a means of re-lighting a pilot flame that has been extinguished by wind or other factor, as long as a continuous burning pilot flame is maintained when vapors can be routed to the combustion device.

Comment: Commenters (2298-Pioneer, 2326-AXPC) request that EPA clarify that operation of a continuous burning pilot is required only when vapors are vented to the control device and should allow use of an automatic ignition device in lieu of a continuous burning pilot.

Commenter (2326-AXPC) explains that the proposed enclosed combustion device (ECD) requirements require operators to ensure flow to the control device is at or above the control device's minimum inlet gas flow rate, and to ensure compliance with this requirement, operators may install a, "backpressure preventer" at the control device inlet to prevent flow to the device that is below the device's minimum inlet flow rate. Where operators use this configuration, the commenter understands the rule would require operation of a continuous burning pilot during times when no vapors are vented to the control device. The commenter explains that for low or intermittent vapor control streams, the "backpressure preventer" may remain closed for much of the time while pressure builds up to ensure requisite inlet vapor flow rate when the control valve opens. The commenter is concerned that in this scenario, the result is that much of the continuous burning pilot's operation may occur when vapors are not vented to the control device, creating an environmental disbenefit. While not required for flares, if an operator installed a control valve at the inlet to the flare, it could similarly monitor when vent gas is going to the flare for combustion, states the commenter.

Commenter (2326-AXPC) proposes that EPA clarify operation of a continuous burning pilot is required only when vapors are routed to the control device. Further, the commenter requests that EPA allow operators to use an automatic ignition device in lieu of a continuous burning pilot, which would avoid unnecessary combustion altogether, as use of an automatic ignition device would ensure combustion occurs when vapors are routed to the control device. Where an operator chooses to operate a continuous burning pilot or automatic ignition device only when vapors are vented to the control device, the commenter proposes the operator would monitor the inlet valve of the control device to demonstrate that the control device was operated with a continuous burning pilot or automatic ignition device when the inlet control valve is open and allowing the passage of vapors to the control device.

Response II-17-2: The commenters did not provide enough clarification on how the requirement for a continuously lit pilot flame can be tied to the backpressure valve while ensuring the flame will be lit when vapors are sent to the control device. While EPA understands the control system could trigger an electronic ignition system to light the combustion device tip when the backpressure valve opens, EPA does not have sufficient information to show that the tip will be lit, with a flame present, by the time the gas travels from the backpressure valve to the flame

zone. Additionally, because a continuously lit pilot adds an additional degree of flame stability to the combustion device, EPA does not sufficient information on whether the sporadic lighting of the combustion device tip would lead to flame instability, and by extension, poor combustion.

Comment: Commenter (2305-Williams) suggests that EPA adopt a 15-minute interval (instead of 5 minutes) as a reasonable period for confirming the presence of a pilot flame in 40 CFR 60.5417b(e)(3).

Response II-17-3: EPA disagrees with the commenter. As discussed in the December 2022 Supplemental Proposal, the 5-minute requirement is in keeping with the requirements of the General Provisions to require a continuous pilot flame. EPA specified a more frequent monitoring interval for the pilot lights than for other continuous parameter monitoring systems because the destruction efficiency will rapidly fall to zero in the absence of a pilot or combustion flame. Therefore, we determined that more frequent readings were needed for the pilot flame monitoring system to ensure the flare or enclosed combustion device achieves 95 percent control at all times.

Comment: Commenter (2254-PBPA) notes EPA has proposed that all flares and ECDs have a continuous pilot flame.<sup>5</sup> But EPA should also allow for auto-ignitors that have flame detection features. Otherwise, operators would be required to supply large amounts of propane to establish a continuous pilot or have a sour gas pilot at sour gas facilities.

Response II-17-4: See response II-17-1, which responds to this issue.

### ***17.1.2 Performance Testing***

Comment: Commenters (2298-Pioneer, 2326-AXPC) request that EPA clarify that an operator need not startup a source for the sole purpose of performing testing or monitoring. The commenters note that requiring operators to startup up emissions sources to avoid missing a periodic testing event would result in emissions that would otherwise not occur, which is counterproductive to the emissions reduction goals of the supplemental proposal, states the commenter. The commenters suggest that EPA should provide operators with a reasonable amount of time following the affected/designated source's return to service to perform testing (that became due while the source was out of service) – e.g., 30 days.

Response II-17-5: EPA agrees that operators should not be required to start up a control device for the sole purpose of testing it. We have added text to the final rule to allow control devices to be tested 30 days after returning to service if they are not operational at the time that a performance test is due.

Comment: Commenter (2399-GPA) expresses that EPA should ensure it understands and considers technical difficulties in testing existing storage vessel controls. The commenter explains that many of the closed vent systems do not have testing ports to accommodate monitoring, nor were these existing systems ever required certification by a qualified individual or professional engineer regarding maximum or minimum instantaneous flow rates. The

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<sup>5</sup> Id. at 74,795.

commenter is further concerned that testing these systems would involve significant technical difficulties as tank systems do not typically provide a high volume, continuous flow, and even where flow may be at high volumes, those periods tend to be sporadic, rare, and for very brief periods of time. EPA must clarify how control device testing at maximum flow rate over the required three-hour period should be accomplished for storage vessels. The commenter states that their members have reported that they are not aware of how to easily simulate storage vessel vapor composition for a continuous three-hour period.

Response II-17-6: Existing facilities that will be regulated under EG OOOOc have three years from the deadline for state plan submittals (which is 24 months after publication of EG OOOOc) to achieve compliance with the proposed provisions. This will give owners and operators time to conduct engineering analyses, if necessary, and to add ports to stacks. As noted in section XI.H.1 of the preamble to the final rule, EPA is finalizing an outlet concentration that can be used to demonstrate compliance in lieu of inlet and outlet testing. This will minimize the issue of needing inlet ports on control devices, which may be more difficult to install than stack ports.

In cases where low flow conditions make three one-hour test runs challenging, delegated authorities have the ability to approve reduced sampling periods. This should be done on a site-specific basis, as the circumstances creating the need for the reduced sampling are specific to each site. The owner or operator should work with the delegated authority to demonstrate the length of test run that can be performed and how the test runs will be representative of normal operating conditions for the control device.

### ***17.1.3 Monitoring - Method 22***

Comment: Commenters (2248-NDPC, 2298-Pioneer, 2326-AXPC, 2428-API) propose less frequent monitoring for visible emissions from combustion control devices. Commenters (2298-Pioneer, 2248-NDPC, 2326-AXPC) propose that as an alternative to the 15-minute Method 22 performance test, operators could evaluate and document whether the control device is smoking or not smoking at least once per week, and if the operator observes smoke emanating from a control device, they will either assume it is smoking and take corrective action or will complete a Method 22 observation within 12 hours to determine if visible emissions are occurring. Commenter (2428-API) suggests that a monthly smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices. Commenter (2326-AXPC) proposes to require the completion of at least one Method 22 test in each semiannual period.

Commenter (2326-AXPC) estimates each 15-minute Method 22 test will require 0.5 hours to 3 hours to complete, which includes travel time, set up time, the observation period, documentation of the procedure, document quality review, organization, and filing for reporting. The commenter anticipates most Method 22 tests will find no visible emissions, meaning operators may spend thousands, if not millions, of hours observing properly operating control devices. The commenter proposes that requiring weekly control device observation, ensures frequent control device evaluation and focus efforts where visible emissions might be occurring – *i.e.*, when the operator observes smoke from a control device. The commenter reports that their operators' experience is that a combustion device will smoke frequently or continuously if the

device will not pass a Method 22 test, meaning the operator is likely to observe smoke from a control device with visible emissions while on location, which would require conducting a Method 22 test under the commenter's proposal.

Commenter (2326-AXPC) recommends that EPA require operators conduct a Method 22 test within 24 hours of smoke observation, rather than contemporaneous with smoke observation, as the personnel that most often visits an oil and gas location may not have sufficient training or expertise to conduct a Method 22 test, but 12 hours provides operators sufficient time to mobilize personnel trained in Method 22 testing.

Commenter (2326-AXPC) requests that, if EPA does not adopt their suggested proposal, EPA reduce the minimum spacing between consecutive Method 22 tests from 15 days to seven (7) days. The commenter believes that the requirement to conduct a Method 22 test approximately every 30 days (assuming a 30-day month), but no more frequently than every 15 days is an overly burdensome administrative requirement, as operators would have a small window to schedule Method 22 tests for potentially thousands of control devices, explains the commenter. The commenter adds that providing for tests no more frequently than every 7 days would significantly reduce this administrative burden while ensuring sufficient operational periods between tests to evaluate control device performance over potentially varying operational conditions, to the extent variability exists.

Commenter (3818-AXPC) recommends that operators be allowed to first evaluate and document whether the control device is smoking or not smoking at least once per week, and if the operator observes smoke, a Method 22 test will be completed within 12 hours to determine if visible emissions are occurring. Further, they propose to complete at least one Method 22 test in each semiannual period.

Commenter (2298-Pioneer) believes that Method 22 opacity tests by trained personnel on a scheduled monthly basis are unnecessary and overly burdensome. They explain that smoking flares, although rare, are easily identified by operations personnel during site visits and, when discovered, are immediately investigated, stopped if safe to do so, and repaired within reasonable timeframes to return the well(s) to production.

Commenter (2428-API) suggests that a monthly smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices. The commenter is concerned that the thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. The commenter states that with each of these observations, requiring 15 minutes and detailed records to document that the observation was conducted according to Method 22, will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. The commenter believes that compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions, or 2) conduct the 15-minute Method 22 observation to determine whether the device

meets the visible emissions requirement, suggests the commenter. A monthly smoking check could reduce the time required to monitor the device by more than 90 percent, and this saved time could be used for other tasks with greater environmental benefit (e.g., conducting a required audio, visual and olfactory (AVO) and/or optical gas imaging (OGI) survey while at the site), explains the commenter.

Response II-17-7: EPA disagrees with the suggestions raised by commenters. EPA Method 22 is a method for the visual determination of emissions, not opacity. It is essentially the same as the smoke/no smoke check requested by the commenters. Observers do not need to be certified to perform EPA Method 22; they only need to be trained and knowledgeable about correct observation technique, such as where to stand to perform a suitable observation. EPA Method 22 also requires minimal documentation of less than a page of information.

By suggesting that the follow-up to a failed smoke/no smoke check is a full EPA Method 22 test and not necessarily action to stop the flare from smoking, the comments imply that a smoking flare may not always be a sustained issue but may be intermittent. Therefore, it is prudent that EPA retain a minimum 15-minute observation period for visible emissions observations, to ensure that intermittent smoking situations are identified.

EPA also disagrees that the timeframe for conducting visible emissions observations needs to be revised. EPA has already provided flexibility on when monthly visible emissions observations must be performed. By further reducing the timeframe between observations to only 7 days, this could mean that a site could go almost 2 months before the next visible emissions observation, which is an unreasonably long time. Commenters have already indicated that operators will be onsite weekly, and as such, there is no need to increase the period between visible emissions observations. We also remind commenters that owners and operators have a duty to maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. If an operator sees a smoking flare at a time other than during a scheduled EPA Method 22 observation, the operator should take steps to reduce visible emissions from the flare.

Comment: Commenters (2248-NDPC, 2298-Pioneer) state that they typically utilize flares and ECDs for backup purposes only; therefore, performing an opacity measurement on a scheduled basis is difficult since control devices are not always receiving a steady, continuous gas flow from affected sources. Commenter (2248-NDPC) explains that they would have to divert gas from the gathering system to make the control device operational for the inspection unless the EPA provided an exception for the monthly inspection for that control device that is only used as backup and at the time of the inspection was not operational.

Response II-17-8: EPA agrees that operators should not be required to start up a control device for the sole purpose of performing visible emissions observations, nor should the operator divert gas from the gathering system to make the control device operational. But gas may still flow or leak to a flare, even when the flare is not operational. Visible emission monitoring is necessary any time that gas may be flowing or leaking to the flare and efficient combustion is needed. For operational control devices, EPA Method 22 observation is only required once every month; at most sites, operators are present at least weekly, which will provide operators with multiple

opportunities to conduct the Method 22 observation. Additionally, as discussed in section XI.H.3 of the preamble to the final rule, EPA has provided an option for owners and operators to use video surveillance cameras in lieu of EPA Method 22 observations, which could help to resolve issues around monitoring control devices that operate sporadically.

Comment: Commenter (2362-EIP et al) states that monthly Method 22 inspections of 15 minutes each cannot ensure compliance with the continuously applicable limit (i.e., no visible emissions from flares and other combustion devices, except for periods not to exceed 1 minute during any 15-minute period). Conducting observations for only 15 minutes once per month would fail to detect visible emissions exceedances in the 30-plus days between tests. Further, the commenter explains that Method 22 observations cannot be conducted at night or under weather conditions (e.g., dark clouds) that make it difficult to detect visible emissions through visible observation. The commenter suggests that EPA's failure to consider these problems renders its proposed monitoring for visible emissions arbitrary and capricious and these problems with EPA's proposed monitoring also mean that the visible emissions requirement does not reflect the best system of emission reduction (BSER). To remedy these problems and ensure continuous compliance with the visible emissions limit for flares and other combustion devices, the commenter suggests that EPA must require video surveillance of all flares and other devices, with infrared (or some other means) to detect visible emissions after dark.

Response II-17-9: EPA disagrees with the commenter. There are many unmanned sites without electricity in the oil and natural gas source category. These types of sources do not have the infrastructure to conduct continuous surveillance of flares with cameras. However, we have added an option to the final rule to allow sources to install video cameras as an option in lieu of conducting visual emissions observations with EPA Method 22. Additionally, while EPA does not currently have a method for use of fixed infrared camera systems, we have also provided a pathway for use of this type of technology once EPA has approved it.

We have also added a requirement to the final rule for alert systems to notify the control room when a pilot light is no longer lit. We believe that this requirement will reduce the instances of inefficient flaring.

#### ***17.1.4 Other (non-Method 22) Monitoring and Alternatives to Monitoring***

Comment: Commenter (2433-EDF et al) generally supports the proposed control device requirements but suggests that EPA re-evaluate the exemptions to the flow rate requirement (i.e., an engineering assessment that the maximum gas flow rate cannot exceed the maximum flare tip velocity or installation of a backpressure preventer). Instead, the commenter suggests that EPA ensure, that in all circumstances, continuous monitoring of pilot light and flow rate occur. The commenter states that such monitoring also will allow operators to accurately report the amount of gas emitted while the flare is unlit, states the commenter.

Response II-17-10: EPA agrees with the commenter that a pilot light should remain lit any time there is the potential for gas to be routed to a combustion control device. See additional responses in section 17.1.1 of this Chapter.



While EPA has revisited and made some revisions to the flow rate monitoring exemptions in the final rule, EPA disagrees that continuous flow monitoring is necessary if the owner or operator can demonstrate that it is impossible to exceed the enclosed combustion device's maximum flow rate or a flow rate of 60 feet per second for flares. EPA concurs that this demonstration should be robust, and we have also added language to require the demonstration to be updated whenever there are changes to the process or control device that would be expected to affect the maximum flow rate to the control device.

Comment: Commenter (2333-LongPath) believes that continuous monitoring with proven capability to identify unlit and malfunctioning combustion devices (e.g., reduced combustion efficiency) should be an allowable monitoring requirement. The commenter points out that even storage vessel affected facilities with advanced controls and equipment monitoring can malfunction or drift off of optimal set points. The commenter believes that top-down monitoring with atmospheric continuous monitors, particularly those with the ability to quantify, can provide extremely valuable information to operators on combustion efficiency and malfunctions in real time, providing rapid and substantive emissions reductions. The commenter states that continuous monitors with the ability to quantify and with proven validity in identifying these types of malfunctions should be an allowable monitoring tool.

Response II-17-11: See discussion in section XI.H.6 of the preamble to the final rule which details EPA's final standards related to alternative approaches to combustion device monitoring.

Comment: Commenter (2428-API) suggests that the monitoring plan for control devices does not need to be site specific. The commenter explains that operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, the commenter believes EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Similar to fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself, explains the commenter. The commenter is concerned that requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

Response II-17-12: EPA agrees with the commenter and has incorporated the same terminology (company-defined area) for control device monitoring plans that is used for fugitive emissions monitoring plans.

Comment: Commenter (2362-EIP et al) states that with respect to the alternative to continuous flow monitoring, EPA must include requirements to reassess the engineering assessment when there are changes to the sources vented to the flare, such as when additional sources are routed to the control device, or those upstream sources change, because the flow rate could increase. The commenter states that failing to do so would likely mean that EPA's flare and control requirements do not reflect BSER and do not ensure proper destruction efficiencies. The commenter further states that EPA must also account for such situations to satisfy the requirement from 40 CFR 60.18(d) that the agency's proposed subparts include "provisions stating how owners or operators of flares shall monitor these control devices." With respect to

EPA's request for comment regarding situations where continuous monitoring of the vent gas flow rate is unnecessary, the commenter states that they are not aware of any such situations.

Response II-17-13: See section XI.H.2 of the preamble to the final rule for a discussion on the final requirements related to the engineering assessment requirements.

Comment: Commenters (2298-Pioneer, 2353-CrownQuest, 2399-GPA, 2428-API) have concerns about the requirements regarding the accuracy of flow monitoring devices. Commenter (2428-API) states that since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly and with the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be  $\pm 10$  percent of maximum expected flow. Historically, the commenter states, the flow monitoring accuracy requirement of  $\pm 2$  percent or better requirement only applied to manufacturer tested control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. The commenter explains that vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Commenter (2428-API) states that the  $\pm 2$  percent accuracy requirement may not be technically feasible for most commercially available meters nor cost effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. Further, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them, states the commenter. The commenter has previously commented<sup>6</sup> on the challenges with flow monitoring at upstream facilities. The commenter reports that this level of accuracy is also more stringent than the  $\pm 5$  percent accuracy requirement for flare vent gas flow rates at velocities above 1 foot per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 Subpart CC (Refinery MACT)<sup>7</sup>.

The commenter (2428-API) explains there are two types of commercially available flow meters that are commonly used: thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the  $\pm 2$  percent accuracy, but this accuracy may decrease under low-flow or low-pressure conditions, states the commenter. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of \$20,000 to \$30,000 each, states the commenter. The commenter cites to EPA's cost analysis for storage vessels controls<sup>8</sup>, and states the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, the commenter explains, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. The

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<sup>6</sup> API's December 4, 2015, comments on the proposed NSPS OOOOa and January 31, 2022, comments on the proposed NSPSs OOOOb and EG OOOOc.

<sup>7</sup> 40 CFR 63 Subpart CC Table 13.

<sup>8</sup> EPA-HQ-OAR-2021-0317-0039, "StTanks\_Control\_Costs\_v5.1.xlsx" and "EPA\_Flares\_Calc\_Sheet\_MP1plusmonitors.xlsx".

commenter states that thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of  $\pm 5$  percent or better at high flows (accuracy decreases at pressures less than 25 pounds per square inch gauge (psig)). The commenter also is concerned that the lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. By way of example, the commenter states that if a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a  $\pm 5$  percent accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the commenter states that the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of  $\pm 2$  percent technically infeasible. Therefore, the commenter requests that the accuracy for control device inlet flow rate be increased to  $\pm 10$  percent of maximum expected flow.

Commenter (2298-Pioneer) states that due to the variability of upstream oil and gas production, continuous parametric monitoring requirements are difficult, if not impossible, to always meet, as the current flow meter technology does not allow accurate flow measurements for intermittent or low flow gas streams as seen in these operations. The commenter explains that differing gas stream compositions make calibration of flow meters difficult, resulting in accuracy issues. The commenter adds they use advanced process simulation software to ensure all flow rates are within design parameters for proper control device destruction efficiency. While the commenter agrees with the potential exemptions available for this continuous monitoring, the commenter proposes EPA exempt flow monitoring for control devices used to control affected facilities with intermittent or low flow gas streams under this rule.

Commenters (2254-PBPA, 2353-CrownQuest) state that commercially available flow meters that meet the required accuracy are either thermal dispersion or ultrasonic. The commenter reports that measuring the flow in closed vent system causes two distinct problematic issues. The normal volumes from working and standing losses and the flashing of separator liquids are at very low velocities that are hard to measure with current measurement technology, explains the commenter. Measuring the flow of flash vapors and peak flow rates would require a device that can go from zero flow to maximum flow in milliseconds and go back to zero just as quickly.

Commenters (2254-PBPA, 2353-CrownQuest) believe that the hysteresis (i.e., the amount that the previous state impacts the future state) and the latency (i.e., the time required to return to steady flow after a transient) of the best commercial measurement devices available today are inadequate for millisecond-scale transients. Currently, for mineral accounting purposes, the commenter provides that the Federal Government and states do not require flow measurement for liquids but only gaging or strapping of the tank because of the lack of adequate measurement technology. Furthermore, ultrasonic meters can be upwards of \$30,000 each, states the commenters and the cost could reach hundreds of millions of dollars in meters for operators across the country, which is not cost-effective and not a BSER.

Commenter (2399-GPA) states that the purpose of the monitoring equipment that would be installed under the supplemental proposal is to monitor general information and ensure complete combustion; the equipment is not being used for complex calculations or controls that would be

required by other rules such as Refinery MACT Subpart CC or the Ethylene MACT. The commenter believes the proposed NSPS OOOOb and EG OOOOc requirements would allow for a very large operating window under normal operations for most midstream control devices and further, the midstream industry uses individual control devices for certain equipment, such as a device only for storage vessels. This means that many control devices see limited flow during a typical year, explains the commenter. The commenter is concerned that despite this, the supplemental proposal would require that flow meters be accurate up to 2 percent at maximum flow rates. In most cases, such accuracy could only be achieved with an optical meter or an ultrasonic flow meter, explains the commenter, at a typical cost of about \$30,000 for basic models. The commenter believes there is no evidence in the record, based on the NSPS OOOOb and EG OOOOc requirements, that these precise and expensive flow meters will provide any benefits over less costly flow meters. As with many other types of flow meters, these also struggle with accuracy at lower flow rates such as when the device is only controlling breathing losses from tanks or pressure safety valve discharges at gas plants, points out the commenter. As a result of these operating issues, even the most accurate flow meters will lose some accuracy, states the commenter. The commenter notes that accuracy at lower rates can increase with additional flow meter monitoring devices installed in tandem with the basic ultrasonic meter, however, this significantly increases the overall cost of this monitoring equipment. The commenter would like to ensure that meters with an accuracy of up to 10 percent at maximum flows, such as thermal dispersion flow monitoring devices, can be used to show compliance with the proposed rule and an accuracy warranted by the instrument provider should be sufficient.

Response II-17-14: EPA agrees with commenters that only specific flowmeters will have an accuracy within 2 percent. In order to broaden the range of flowmeters that can be used on combustion control devices in NSPS OOOOb and EG OOOOC, recognizing the larger universe of control devices that will need to be monitored, and to relieve the challenges of monitoring flow to these devices, EPA is changing the accuracy requirement for flowmeters on combustion control devices to plus or minus 10 percent of the maximum expected flow rate. This change should still provide adequate compliance assurance for these devices while providing owners and operators with more flexibility to conduct monitoring.

Comment: Commenter (2403-PAO) requests that EPA include the following in the final rule:

1. An exception for low emitting or intermittent gas producing facilities to utilize automatic ignition systems and/or a pit flare if a continuous burning pilot and a 95 percent efficient flare or combustion device is technically infeasible due to consistently low or intermittent flow and/or would require additional purchased gas as determined by an in-house engineer.
2. An exception for shut-in facilities such that flares and/or combustors are not required to be operated when the associated wells are not producing or when liquid is not flowing to the associated tanks.
3. A provision for operators to use engineering methods to establish a “model” piece of equipment and apply the test results elsewhere under like conditions, flow, net heating value (NHV), etc., instead of conducting tests on each combustion device as determined by an in-house engineer.

4. A provision for a lower destruction efficiency of 93 percent to be recognized during temporary reductions of flow that cause vapor flow to a flare or combustor to fall under the minimum required flow for demonstrating 95 percent reduction.

Commenter (2403-PAO) explains that for older wells and facilities with low or intermittent vapor flow to a flare or combustor, there often is not enough gas produced by the well to keep a pilot continuously lit or to produce enough tip velocity to meet the flow rate requirements and promote the mixing of gas and air necessary to achieve 95 percent destruction efficiency in a flare or combustor. For this reason, the commenter explains that many states have provisions for using automatic ignition systems that spark every few seconds to ensure a flame is initiated when gas is present, and/or pit flares for low emitting facilities. If a continuous burning pilot were required for such a site, it would be necessary to purchase additional natural gas, propane, or butane to maintain the pilot at all times, regardless of whether gas was being sent to the flare or enclosed combustion device, explains the commenter. The commenter states this would unnecessarily create more emissions than an equivalent flare with an automatic ignition system, and often the additional emissions from the continuous flame would exceed the emissions of a less efficient combustion system that only combusted when gas was present.

Commenter (2403-PAO) also points out that when wells are shut-in, tank emissions are reduced to breathing emissions which are very minimal and often there is not enough flow to the flare or control device to prevent flashback and an explosion, which create greater environmental and safety impacts than the minimal breathing emissions. After multiple tank fires in North Dakota, the commenter states that the North Dakota Department of Environmental Quality (NDDEQ) acknowledged this risk and issued guidance that allows for tank vapor flares and control devices to be bypassed when a well is shut in to minimize the risk. In these cases, the hatches may need to be left open to relieve breathing pressure due to temperature fluctuations throughout the day, explains the commenter. Further, the commenter states it is common to isolate a tank that needs repair, empty the tank, and leave the hatch open to vent vapors to allow for repair, which can take several days. Finally, the commenter adds that if a vapor recover unit and flare are not required at a facility, then tank emissions are understood to be vented to atmosphere in their entirety, regardless of whether the emissions occur from tank vents, openings, conservation vent valves, pressure relief valves, or a thief hatch.

Commenter (2403-The PAO) states that low pressure vapor flow monitoring is very difficult and expensive to accurately and consistently measure and will lead to wells being shut in before their associated reservoirs are depleted. Further, the commenter adds that the supplemental rule is not clear on whether each device would require a test. The commenter believes that operators should be able to use engineering methods to establish a “model” piece of equipment and apply the test results elsewhere under like conditions, flow, British thermal unit (Btu), etc., instead of conducting tests on each combustion device, and suggests that this would reduce unnecessary costs on operators.

Finally, commenter (2403-PAO) points out that it is possible for a higher producing facility to temporarily decrease production such that the minimum flow rate to a combustor or flare are temporarily not met. The commenter explains this is especially true when a facility is being shut in or started up. In such a condition, if a flare or combustor has a flame, then it is burning vapors,

and a temporary low flow condition should not be considered a violation if its temporarily not possible to meet a minimum flow rate requirement, states the commenter. The commenter states that Texas recognizes this and has provisions in its highly reactive (HR) volatile organic compounds (VOC) (HRVOC) control program for a flare which temporarily does not meet the conditions of 40 CFR 60.18 to be calculated as having a 93 percent destruction efficiency, based on observations from the 2010 Texas Commission on Environmental Quality (TCEQ) Flare Study<sup>9</sup>. According to the commenter, without such a provision, they are concerned that an operator would be forced to choose between 95 percent and zero percent destruction for short-term periods of low flow, neither of which is correct.

Response II-17-15: See response II-17-1, which addresses the issue of continuous pilot flames.

With respect to storage vessels that are connected to wells that are shut in, EPA refers the commenter to §60.5395b(c), which contains the requirements for storage vessel affected facilities that are removed from service or returned to service. A storage vessel is not an affected facility under NSPS OOOOb for the period that it is removed from service, provided that the operator follows the procedures and reporting under that section. Tanks that are not currently in service do not require owners and operators to meet control standards. Additionally, tanks that are used intermittently may not meet the definition of an affected source under NSPS OOOOb or EG OOOOc.

See Response II-17-14, which addresses the issue of flow measurement accuracy. Additionally, NSPS OOOOb and EG OOOOc allow for pressure monitors in lieu of flow monitors, which can resolve some of the issues with monitoring low flow streams. NSPS OOOOb and EG OOOOc also provide an exemption from continuous flow monitoring if the owner or operator installs a backpressure regulator valve and conducts an engineering analysis to show that the unit will operate below the maximum established flowrate.

NSPS OOOOb and EG OOOOc do include provisions for use of manufacturer tested enclosed combustion devices, which would be conducted in lieu of the initial test on these control devices. Additionally, some control devices, like condensers and carbon adsorbers, do not have to be tested, and owners and operators may use a design analysis instead. Similarly, flares are not required to be tested, but must demonstrate compliance with the requirements specified in the rule. Finally, §60.8(b) allows the delegated authority to approve shorter sampling times when necessitated by process variables and to waive performance tests if the owner or operator can demonstrate by other means, to the satisfaction of the Administrator, that the affected source is in compliance with the standard. Identical control devices with identical operating conditions could be a situation in some circumstances in which the delegated authority is satisfied that both control devices can meet the standard by only testing one control device. Finally, EPA notes that it has only specified a particular control efficiency, not a particular type of control device. Flares or other combustion devices may not make the most sense economically or from a control standpoint in all situations, particularly for control of low, intermittent flow streams.

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<sup>9</sup> See [https://www.tceq.texas.gov/airquality/stationary-rules/stakeholder/flare\\_stakeholder.html](https://www.tceq.texas.gov/airquality/stationary-rules/stakeholder/flare_stakeholder.html).

The required BSER for various affected facilities in NSPS OOOOb and EG OOOOc is 95 percent control. As such, owners and operators must meet 95 percent control of emissions from affected or designated facilities subject to those standards at all times.

Comment: Commenter (2326-AXPC) requests that EPA confirm its intent to exempt properly designed facilities from the requirement to monitor control device inlet flow, if the operator designs its control system to prevent the possibility of inlet flow to a flare or ECD being outside of its design capacity range. The commenter further requests that EPA revise the inlet flow monitoring requirements for ECDs performance tested by the manufacturer to be consistent with the flow monitoring requirements for ECDs performance tested by the operator.

Response II-17-16: EPA confirms that the commenter's interpretation is correct. Additionally, EPA agrees that it is reasonable to require the same flow monitoring for all ECDs, whether they are tested by the operator or manufacturer. The final rule has been updated to align these requirements.

Comment: Commenter (2326-AXPC) suggests that EPA should allow operators to monitor control device inlet pressure in lieu of monitoring flow. The commenter explains that existing flow meter technology cannot accurately measure flows that are generally of low velocity with intermittently high velocity, and data obtained from a flow meter in this application will be inaccurate and misleading. By way of example, the commenter explains that gas flow from a typical storage vessel into a closed vent system (CVS) predominantly results from flashing vapors, which significantly outweigh the volume of working and standing emissions that occur between flashing events. The normal volumes from working and standing losses are typically at very low velocity, which is difficult to measure with current technology, whereas the volume associated with flashing vapors is typically higher, states the commenter. The commenter explains that measuring the flow of flash vapors and peak flow rates would require a device that can go from zero or very low flow to maximum flow in milliseconds and be able to go back to zero or very low just as quickly. The hysteresis (*i.e.*, the amount that the previous state impacts the future state) and the latency (*i.e.*, the time required to return to steady flow after a transient) of the very best commercial measurement devices available today are both inadequate for millisecond-scale transients, warns the commenter.

Commenter (2326-AXPC) also notes that differing gas composition may reduce the accuracy of flow meters, which are calibrated to a specific gas composition. The commenter anticipates that many of the oil and gas flares and ECDs will control storage vessels, and the composition of storage vessel gas varies depending on the conditions in the vessel. By way of example, the commenter explains that flash gas vapor has a different composition (more lighter end carbon chain hydrocarbons) than working and breathing emissions (more heavier end carbon chain hydrocarbons). Because of this variable gas composition, states the commenter, a flow meter installed to measure storage vessel vapor flow cannot be calibrated to accurately measure all types of storage vessel vapor flow. As an alternative, the commenter suggests that operators can install and operate a pressure monitor at the inlet to a combustion control device to demonstrate inlet flow to the control device is within the device's design range. The commenter's understanding is that pressure monitors are not plagued by the issues noted above for flow monitors and can achieve reasonably accurate measure of pressure more readily than flow

monitors can measure flow. Moreover, combustion control device manufacturers typically provide design capacity curves in terms of pressure, rather than flow, states the commenter, and pressure correlates directly to combustion control device performance and is an appropriate parameter to monitor for demonstrating proper operation of a control device.

This commenter (3818-L-AXPC) submitted a flow capacity curve with pressure on the x-axis and flow rate on the y-axis that presents a graphical representation of the relationship between the inlet pressure and the corresponding flow rate. The commenter notes that it helps illustrate how changes in pressure can impact the flow capacity and performance of the combustion device. The commenter adds that it is important to note that at low inlet pressure, the flow rate may be limited, resulting in lower flow capacity and potentially reduced combustion performance. As a result, and as they state is illustrated in the presented flow capacity curves, a defined minimum inlet pressure is established (1 oz/in<sup>2</sup> in this example) before a minimum flow rate can be provided. Based on the example flow capacity curve, the commenter believes that it can be concluded that minimum inlet pressure is actually more impactful to ensure the stated destruction efficiency than the minimum flow rate. Additionally, in order to verify an ECD is not operating below the minimum pressure, a valve is needed to restrict flow to the ECD before inlet pressure drops below what the manufacturer has established as the minimum inlet pressure. They add that the pressure monitoring used for the actuation of these valves can also be applied for inlet pressure monitoring to the ECD. In this scenario, they state that there is no need to install a meter to monitor flow rate as monitoring pressure and flow rate is repetitive and unnecessary. As such, the commenter proposes that if an operator can work with a manufacturer and document the corresponding operating pressures to meet their guaranteed destruction efficiency as demonstrated during the subject performance test, then pressure monitoring should be allowed.

The commenter (3818-L-AXPC) added that they have also learned that the current Colorado rule (Regulation 7) allows for use of pressure monitoring through submittal and approval of an “Alternative Technology and Infeasibility Request”. Further, on April 4th, 2023, Air Pollution Control District (APCD) proposed revisions to Regulation 7 to include allowance of Pressure Actuation Systems as a standard rather than an exemption. The Statement of Basis and Purpose submitted by the Division along with the proposed Regulation 7 revisions contains language explaining the purpose for adoption of the alternative to flow meters in rule language. The Division states: “The Commission adopted an acceptable alternative to flow meters, a pressure actuator system, for monitoring enclosed combustion devices to confirm that the enclosed combustion device is being operated appropriately. A pressure actuator system monitors pressure and provides an operator more control of their vapor control system to ensure it is operating within design parameters. This system was discussed as an alternative in 2021, but the concept was not clearly understood by the Division or operators at that time. The Division has since approved several proposals that use pressure actuator systems as an alternative to flow meters. The commenter recommends that this lesson learned on the benefits of using a pressure monitoring system be transferred to the current EPA rulemaking for controls regardless of whether it is manufacturer or owner tested as it is the more superior way to manage flow in these situations. The commenter also recommends that EPA reconsider the accuracy requirement of  $\pm 2$  percent or better in all cases.  $\pm 2$  percent is generally the standard for product going to sales and thus royalty and revenue generating. However, for control efficiency, they state that maintaining operating parameters in the desired range can be achieved by adjusted alarm points



to compensate for decreased accuracy making the  $\pm 2$  percent rate unnecessarily restrictive for this purpose. The requirement of  $\pm 2$  percent can only be achieved by a very limited set of metering technologies and may require operators to retrofit existing installations at significant cost with little or no discernible emissions reduction. In many cases it is not technically or commercially feasible to make these retrofits, these challenges only further compounded by present day supply chain restraints. In addition, in some operational scenarios the maximum expected flow rate may not be achieved, which therefore limits calibration and introduces inaccuracy at volumes outside the calibration range. To avoid these concerns, AXPC recommends that an accuracy requirement of  $\pm 5$  percent be allowable as this will encompass most metering technologies employed without sacrificing emission reduction. This recommended level of accuracy would then be consistent with the  $\pm 5\%$  accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 Subpart CC (RMACT).

Response II-17-17: See responses II-17-14, II-17-16, and II-17-21, which address the issues in this comment.

#### ***17.1.5 Regulatory Language and Clarifications***

Comment: Commenter (2399-GPA) appreciates EPA's intent to consolidate the proposed control device provisions into one section, but suggests the resulting regulatory text requires some further clarification to ensure end users fully understand all the requirements and do not unintentionally misunderstand monitoring and testing requirements. As a general matter, the commenter urges EPA to consider streamlining and reorganizing the regulatory text to improve clarity. As written, the commenter cautions that the proposed regulatory language is extremely complicated and difficult to follow. As an example, the commenter points to proposed 40 CFR 60.5417b which explains "[w]hat are the continuous monitoring requirements for my control device?" The commenter notes that this is an important section imposing binding obligations upon regulated owners and operators, however, the commenter is concerned with the layers of subsections (in this example, the commenter notes that the explanation of an owner or operator's obligations goes as far as 40 CFR 60.5417b(d)(1)(viii)(C)(1)). The commenter is further concerned about numerous cross-references to other sections and sub-sections, which they are afraid will make it easy for readers to become lost, confused, or misinterpret the regulation's intent. The commenter notes that for most of the commenter's members, engineers and technicians manage regulatory compliance, not sophisticated legal counsel. The commenter urges the agency that any finalized regulatory language should be in a more streamlined and simplified form, organized so that all the requirements for specific control devices may be found in one place, and written so that those subject to the rules can clearly understand them.

Response II-17-18: EPA acknowledges the commenter's concern. EPA has worked to streamline requirements in the final rule where possible.

Comment: To address commenter (2326-AXPC) suggestion that EPA allow operators to monitor control device inlet pressure in lieu of monitoring flow [see section 17.1.4 of this Chapter for support for their position], the commenter provides the following redline of 40 CFR 60.5417b(d)(vii)(A) and 60.5417c(d)(vii)(A) (underlined text indicates new text):

The continuous parameter monitoring system must measure gas flow rate or pressure at the inlet to the control device. The monitoring instrument must have an accuracy of  $\pm 2$  percent or better at the maximum expected flow rate. The flow rate or pressure at the inlet to the combustion device must be equal to or greater than the minimum flow rate or pressure and equal to or less than the maximum flow rate or pressure determined by the manufacturer.

Response II-17-19: In the final rule, EPA has aligned the monitoring requirements for all enclosed combustion devices, so the paragraph referenced by the commenter no longer exists. In the flow monitoring requirements for flares and enclosed combustion devices, the final rule clearly states that flow monitoring can be conducted with direct flow meters or other parameter monitoring systems such as inlet line pressure monitoring.

Comment: Commenter (2326-AXPC, 3818-L-AXPC) points out that in 40 CFR 60.5417(d)(1)(viii)(D)(2), EPA provides an alternative to control device inlet flow monitoring where the operator installs and operates “a backpressure preventer which is set to operate at or above the minimum inlet gas flow rate.” EPA does not, however, define the term “backpressure preventer,” and the commenter is not aware that such a device exists. However, the commenter believes EPA intends to mean a control valve installed at the inlet to a control device that is set to remain open when the inlet pressure to the control device is at or above the device’s minimum inlet gas flow rate. Accordingly, the commenter proposes that EPA revise 40 CFR 60.5417b(d)(viii)(D)(2) and 60.5417c(d)(viii)(D) (2) as follows (underlined text indicates new text and struck out text indicates deleted text):

If you install and operate a backpressure preventer control valve which is set to operate remain open only at or above the minimum pressure corresponding to the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

Response II-17-20: EPA agrees with the commenter that the term “backpressure preventer” requires clarification but does not agree that “control valve” is the appropriate term. Control valves are generally understood to actuate based on a signal from a monitor, such as a flow monitor or pressure monitor. For the flow monitoring exemption to apply, the installed valve must operate without reliance on such a monitor. Accordingly, EPA is replacing the term “backpressure preventer” in the final rule with “backpressure regulator valve” and further explains that it must be calibrated to open at the minimum pressure set point corresponding to the minimum inlet gas flow rate. By adopting the term “backpressure regulator valve” and additional requirements for the valve set point, EPA is clarifying that the exemption applies only upon the installation, calibration, maintenance, and operation of a valve that does not rely on a monitor.

Comment: Commenter (2399-GPA) notes that while 40 CFR 60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D) allow for the use of “other parameter monitoring systems combined with engineering calculations,” they do not believe it is clear whether EPA intends to allow the use of a pressure monitor. The commenter notes that because combustion control device performance directly corresponds to the device’s operating pressure, no further engineering calculation is necessary. Accordingly, the commenter proposes that EPA allow operators to monitor inlet

pressure to a combustion control device to demonstrate the device is operating within its design capacity without further engineering calculation, or clarify that 40 CFR 60.5417b(d)(vii)(A), (d)(viii)(D) and 60.5417c(d)(vii)(A), (d)(viii)(D) allow the use of a pressure monitor in lieu of a flow monitor for all applicable control devices (whether manufacturer or owner tested).

Consistent with this request, the commenter (2399-GPA) provides the following redline of 40 CFR 60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D) (underlined text indicates new text):

You may use direct flow meters, direct pressure monitors, or other operating parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement.

Another commenter (3818-AXPC) provides the following suggestion for §§60.5417b(d)(viii)(D) and 60.5417c(d)(viii)(D) (underlined text indicates new text):

You may use direct flow meters, monitoring of the pressure of the vapor control system, or other operating parameter monitoring systems combined with engineering calculations, such as line pressure and burner nozzle dimensions, to satisfy this requirement.

Response II-17-21: EPA disagrees with the suggested changes. We also disagree that no calculations are necessary to determine flow from pressure readings. Because the parameter that is being monitored is flow, engineering calculations are necessary to convert the pressure reading to a flow reading. Often this is easily accomplished through flow curves. As such, we have finalized, as proposed, an allowance for owners and operators to use pressure monitoring systems in lieu of direct flow monitoring; this requirement applies to all combustion devices, whether they are tested by the manufacturer or the owner or operator.

Comment: Commenter (2428-API) requests clarification on the proposed requirement language around the presence of pilot flames. The commenter notes that the proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A “continuous burning pilot flame” means a pilot flame is required at all times regardless of whether the site is operating, or vent gas is sent to the control device.
- A “pilot flame present at all times of operation” could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)
- “Pilot flame while emissions are routed to the control device” means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

Commenter (2428-API) suggests that a pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. The commenter also notes that this clarification would allow for the use of automatic ignition systems and would maintain consistency with the compliance requirement found at 40 CFR 60.5412b(b)(1):

You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

Commenter (2428-API) offers the following changes that clarify a pilot flame should be required only when emissions are routed to the control device, like some state rules including New Mexico<sup>10</sup> (underlined text indicates new text and struck out text indicates deleted text):

*40 CFR 60.5412b(a)(1)(vii):*

You must install and operate a continuous burning pilot flame or automatic ignition system.

*40 CFR 60.5413b(e)(2):*

A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.

*40 CFR 60.5415b(f)(1)(vii)(A)(1):*

A pilot flame or combustion flame must be present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.

*40 CFR 60.5417b(d)(1)(i):*

For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of  $\pm 1$  percent of the temperature being monitored in °Celsius, or  $\pm 2.5$  °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.

*40 CFR 60.5417b(d)(1)(vii)(B):*

A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame or combustion flame while emissions from affected facilities are routed to the control device.

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<sup>10</sup> 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC.

*40 CFR 60.5417b(d)(1)(viii)(A):*

Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

*40 CFR 60.5417b(g)(1):*

A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.

*40 CFR 60.5417b(g)(6)(iii):*

There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.

*40 CFR 60.5420b(c)(11)(i)(F)(1):*

Records that the pilot flame or combustion flame is present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.

Response II-17-22: EPA disagrees with the commenter's interpretation of the continuous pilot flame requirements. §60.18(e) requires flares to be operated at all times when emissions may be vented to them. Further, §60.18(c)(2) requires flares to be operated with a flame present at all times. Therefore, flares must be operated with a flame present at all times whenever there is the possibility that emissions could be vented to the flare.

EPA recognizes that at proposal some places within the text used both the pilot flame and combustion flame terms while other places only used pilot flame. To provide consistency, we have updated the final NSPS OOOOb and EG OOOOc to consistently use both terms.

Regarding automatic ignitions systems, see response II-17-1, which responds to this issue.

Comment: Commenter (2428-API) requests the clarification of which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame. The commenter notes that the proposed control device monitoring plan requirement at 40 CFR 60.5417b(c)(2) includes the following exemption: "...Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section."<sup>11</sup> However the commenter notes that one of the listed monitoring plan elements uses a thermocouple as an example. The commenter contends that this example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter, notes the commenter. The commenter urges EPA to clarify which elements of the monitoring plan apply to heat sensing devices and recommends the following redline for 40 CFR 60.5417b(c)(2)(ii) (struck out text indicates deleted text):

Sampling interface (~~e.g., thermocouple~~) location such that the monitoring system will provide representative measurements.

Alternatively, commenter (2428-API) suggests that EPA could propose a different example for sampling interface.

Response II-17-23: As the commenter has noted, EPA has already stated in the regulatory text that certain provisions of the monitoring plan do not apply to heat sensing monitoring devices, as these devices are used qualitatively, not quantitatively. The sampling interface location is relevant to all thermocouples, even thermocouples used for pilot flame determination. In the case of heat sensing thermocouples, the monitoring plan should demonstrate that the location of the thermocouple is adequate for determining that a pilot flame is present.

Comment: Commenter (2428-API) suggests that flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices. The commenter also has suggestions for flare monitoring requirements.

The commenter (2428-API) explains that manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at 40 CFR 60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at 40 CFR 60.5417b(d)(1)(viii)(D), the commenter noted the following inconsistencies and requested that they be addressed.

- No accuracy requirement is specified for other enclosed combustion devices. As discussed above, the accuracy requirement for flow rate monitoring should be  $\pm 5$  percent for both manufacturer-tested and other enclosed combustion devices.
- Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems. Other parameter

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<sup>11</sup> 40 CFR 60.5417b(c)(2).

monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices<sup>12</sup>.

- Manufacturer-tested devices do not have an option to exempt the device from flow monitoring. For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- EPA should clarify that a backpressure preventer is a backpressure valve. Since backpressure preventer is an unclear term, EPA should use the term “backpressure valve” instead.
- Additional examples of other parameter monitoring systems should be added to the regulatory text. To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, commenter (2428-API) offers the following recommended changes to the flow monitoring requirements for manufacturer-tested control devices in 40 CFR 60.5417b(d)(1)(vii)(A) (underlined text indicates new text and struck out text indicates deleted text):

Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~The~~ continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of  $\pm 2 \pm 10$  percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.

(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.

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<sup>12</sup> 40 CFR 63.773(d)(3)(i)(H)(1).

(2) If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

(3) Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(4) Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

Commenter (2428-API) also offers the following recommended changes to the flow monitoring requirements for control devices not tested by the manufacturer in 40 CFR 60.5417b(d)(1)(viii)(D) (underlined text indicates new text and struck out text indicates deleted text):

Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of  $\pm 10$  percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.

(1) If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.

(2) If you install and operate a backpressure ~~preventer valve~~ which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.

(3) Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

(4) Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.

Given the small size, dispersed nature, and large number of units affected by this rule, the commenter (2428-API) suggests that these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.



Response II-17-24: As noted in responses II-17-16 and II-17-20, in the final rule EPA is revising the terminology for backpressure preventer and aligning the monitoring requirements for all enclosed combustion devices, regardless of whether they are tested by the manufacturer or the operator. EPA has also clarified line pressure to inlet line pressure and added line size in the regulatory text for parameter monitoring systems.

Comment: Commenter (2399-GPA) asks for the EPA to clarify what may be an “affected facility” for the control device requirements and how to handle the situation where a control device controls emissions from both an affected facility subject to new source standards and one subject to existing source standards. The commenter is concerned that the proposed regulatory text that describes control device requirements for various “affected facility” types is incomplete. By way of example, the commenter cites to proposed 40 CFR 60.5415b (including “well affected facility,” “wet seal centrifugal compressor affected facility,” “pneumatic pump affected facility” and others). The commenter notes that there are multiple sections in the proposed regulatory text where a control device can be used to control emissions from a source, but it is not clear whether the source is subject to the testing requirements under 40 CFR 60.18(d). The commenter requests clarification on whether control devices used for those sources must be tested every five years.

Further, the commenter (2399-GPA) points out that it is common for multiple equipment types, such as pneumatic pumps and rod packing vents, to be routed to a common control device. The commenter is concerned that it is not clear if adding new equipment that are “affected facilities” under the proposed regulations to the common control device will make all equipment routed to the common control device affected facilities. The commenter urges EPA to clarify that equipment that is merely routed to the same control device as an “affected facility” will not cause existing equipment to become “affected facilities.”

Similarly, commenter (2399-GPA) recommends that the EPA clarify requirements for flares that control a mix of new and existing sources, such as where an affected facility installs a new pneumatic pump or compressor that is then routed to the same flare controlling other existing sources. The commenter believes that the proposed regulatory text is not clear as to whether routing new sources to an existing flare would be authorized if the existing flare does not meet NSPS OOOOb monitoring requirements. To the extent that the supplemental proposal expects midstream facilities to install new control devices for new affected facilities, the commenter states that EPA should understand that new control devices will create additional pollutant emissions. If the supplemental proposal expects midstream facilities to modify existing control devices to accommodate both new and existing sources, the commenter requests that EPA provide more time for compliance. Installing new flow meters, testing ports, or NHV measurement tools on existing control device lines handling multiple units or sources involve “hot tap” safety protocols, explains the commenter and this is specialized work that is typically handled by only a small handful of qualified contractors, not in-house staff. Therefore, if EPA expects an entire industry to modify existing flares, the commenter believes that the compliance deadline must account for the relatively small labor pool available to perform that work.

Response II-17-25: EPA is uncertain which affected facility types the commenter believes are missing. As stated in 40 CFR 60.5415b(f), the control device requirements apply to each well, centrifugal compressor, reciprocating compressor, process controllers in Alaska, storage vessel,

process unit equipment, or pump affected facility referenced to paragraph (f) from other paragraphs in 40 CFR 60.5415b. This covers all the affected facility types that are potentially subject to control standards. If an affected facility is subject to control requirements, the control device used is subject to all specified testing and monitoring requirements in 40 CFR 60.5412b, 5415b, and 5417b.

We are clarifying that routing non-affected facilities to control devices used for affected facilities does not change the status of the non-affected facilities, i.e., these non-affected facilities do not become affected facilities just because an owner or operator has routed them to a common control device.

New affected facilities do not necessarily require new or separate control devices. However, affected facilities in NSPS OOOOb must comply with the level of control specified in the rule, and any control device used to achieve the level of control specified in the rule must meet the control device requirements in the rule. Additionally, owners and operators may use new control devices if existing control devices cannot be retrofitted; owners and operators are not limited to their existing control devices.

Comment: Commenter (2428-API) suggests that idle control devices at a site should be exempt from performance testing and monitoring requirements. The commenter is concerned because they believe the proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site, explains the commenter. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on, states the commenter. The commenter explains that in actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc, states the commenter.

Commenter (2428-API) suggests that one potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device, explains the commenter. The commenter is further concerned that a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. The commenter notes that EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ and MACT ZZZZ and believes that similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

To clarify that idle control devices are exempt from performance testing and monitoring requirements, commenter (2428-API) offers the following changes to the regulatory text to address their concerns (underlined text indicates new text and struck out text indicates deleted text):

*40 CFR 60.5400b(a):*

*General standards.* You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to~~ comply-operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.

*40 CFR 60.5401b(a):*

*General standards.* You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply-operated for the purpose of complying~~ with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.

*40 CFR 60.5412b:*

You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.

*40 CFR 60.5412b(a):*

Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under §60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).

*40 CFR 60.5412b(b)(1):*

You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

*40 CFR 60.5417b:*

You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.

*40 CFR 60.5417b(a):*

For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.

Response II-17-26: EPA disagrees that the wording changes suggested by the commenter are necessary. If a control device is used to comply with the emission reduction standards for an affected or designated facility, it is subject to the monitoring and testing requirements specified in NSPS OOOOb and EG OOOOc. Additionally, EPA is uncertain how the owner or operator would prove that the control device is not needed to meet the emission reduction standards specified in the rule if the units are in series or manifolded together. §60.8(b) allows the delegated authority to waive performance tests if the owner or operator can demonstrate by other means, to the satisfaction of the Administrator, that the affected source is in compliance with the standard. The situation described by the owner or operator should be handled on a site-specific basis, in which the owner or operator demonstrates that the control device is either meeting the standard by other means or that the control device is used for other purposes.

EPA agrees that operators should not be required to start up a control device for the sole purpose of testing it. We have added text to the final rule to allow control devices to be tested 30 days after returning to service if they are not operational at the time that a performance test is due.

Comment: Commenter (2288-NDDEQ) believes there is a referencing error in the performance testing procedures for control devices in EG OOOOc. The commenter notes that in NSPS OOOOa/b, the performance testing procedures are found in 40 CFR 60.5413a/b, but in EG OOOOc, they are found in 40 CFR 60.5407c. Despite this, the commenter notes the following references to 40 CFR 60.5413c, which do not exist. The commenter believes the correct reference should be to 40 CFR 60.5407c. Alternatively, the commenter suggests that the performance testing procedures in EG OOOOc be moved to a new section 40 CFR 60.5413c to maintain parity with NSPS OOOOa/b/c.

1. At 40 CFR 60.5398c(b)(4)(iv), "If the results of the periodic screening in paragraph (b)(4)(i) of this section indicate a confirmed detection at a designated facility, and the ground-based monitoring survey and inspections required by paragraph (b)(4)(ii) of this section demonstrate the confirmed detection was caused by a failure of a control device subject to §60.5413c..."

The commenter (2288-NDDEQ) believes that §60.5413c presumably should be replaced with §60.5407c.

2. At 40 CFR 60.5412c(a)(1)(vi), "You must operate each enclosed combustion control device at or below the maximum inlet gas flow rate established in accordance with 60.5417c(f) and as determined in your performance test conducted in accordance with 60.5413c(b)."

The commenter (2288-NDDEQ) believes that §60.5413c(b) presumably should be replaced with §60.5407c(b).

Response II-17-27: The commenter is correct in that the references to §60.5413c should have been references to §60.5407c. EPA has updated the final rule to move the performance testing requirements in EG OOOOc to §60.5413c, to better align with the same requirements in NSPS

OOOOa and NSPS OOOOb. The references to the performance testing requirements have been verified in the final rule.

Comment: Commenter (2214-BCAO) states that 40 CFR 60.5417c(d)(1)(viii)(C) cites, in the first sentence, (d)(1)(ix)(C)(1) through (5). The commenter believes the citation should be (d)(1)(viii)(C)(1) through (5).

Response II-17-28: The commenter is correct in that the reference to (d)(1)(ix)(C)(1) through (5) in 40 CFR 5417c(d)(1)(viii)(C) should have been (d)(1)(viii)(C)(1) through (5). EPA has updated the regulatory text in the final rule and verified the references.

Comment: Commenter (2428-API) recommends the following suggested change to 40 CFR 60.5413b(d)(11)(iii) (underlined regulatory text indicates new text):

A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC and methane (if applicable) required under this subpart.

Response II-17-29: EPA agrees with the suggested change and has updated the final rule accordingly.

#### ***17.1.6 Alternative Technology***

Comment: Commenters (2336-Kuva Systems, 2428-API, 2298-Pioneer, 2326-AXPC) suggest that EPA should permit the use of cameras for operators to perform visual inspections of flare and combustor smoke under Method 22. Commenter (2336- Kuva Systems) states that monthly inspections of flares and combustors for presence of smoke by in-person site-visits and based on section 11 of Method 22 is needlessly expensive and prescriptive. The commenter points out that visible cameras such as security cameras are widely available and deployed at oil and gas sites and they can be positioned closer than 400 m to combustors and flares and can be positioned such that they can view potential smoke from combustors and flares. The commenter believes that having a remote observer view flares and combustors for smoke eliminates the cost of travel and is expected to be cheaper even when considering the cost of cameras and communication. The commenter recommends that EPA clarify that operators can utilize visible light cameras to remotely observe flares and combustors for smoke and specify requirements for installation and operations such cameras need to meet. Moreover, the commenter recommends that EPA clarify that operators can employ qualified individuals from 3rd parties to conduct such monitoring for smoke or to allow it to be automated with machine vision. The commenter also requests that EPA clarify which process a technology solution provider should follow to demonstrate equivalency with EPA's on-site smoke monitoring requirement.

Commenter (2428-API) also suggests that video cameras should be allowed as an alternative method to Method 22, since some sites are already equipped with video camera systems. The commenter notes that video camera systems are allowed as an alternative to Method 9

observation under Broadly Applicable Approved Alternative Test Method ALT-82.<sup>13</sup> Although these video camera systems have similar supply challenges to other monitoring equipment, they should be an allowed monitoring alternative, suggests the commenter. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month, suggests the commenter. Under this scenario, the commenter notes that owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. The commenter also suggests that artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. According to the commenter, making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative, including recordkeeping and reporting of additional video records, which could pose potential security risks and data storage concerns.

Response II-17-30: See Section XI.H.3 of the preamble to the final rule for a discussion on the final requirements related to using cameras in lieu of conducting EPA Method 22 observations.

In this final rule, EPA has not specified who must conduct the visible emissions observation. As with other requirements of the rule, such as fugitive emissions surveys, we are aware that owners or operators may find it easier or more economical to contract services. The rule does not preclude owners and operators from doing so, although ultimate responsibility for compliance with all requirements of the rule lie with the owner or operator.

Comment: Commenter (2433-EDF) states that while they support the requirements for no visible emissions and monthly monitoring using Method 22, they suggest that the EPA could also consider alternative monitoring technologies and methods that would achieve equivalent or superior results. The commenter urged EPA to also require that flares and control devices be monitored for compliance assurance during all fugitive emissions surveys, both under the OGI and AVO program and under the alternative periodic screening options. The commenter stated that control devices and flares, especially unlit and malfunction flares, are among the most observed and largest sources of methane emissions, including superemitter events, and it is therefore critical that they are regularly inspected and monitored to ensure proper operation.<sup>14,15</sup> The commenter further stated that multi-basin research has identified unlit flares across the entire country, and a Permian Basin study using flights conducted in 2020 found 5% of all active flares were unlit.<sup>16</sup> Moreover, commenter contends that monitoring flares and control devices during fugitive emission surveys poses very little additional burden and can ensure emission events are avoided.

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<sup>13</sup> <https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf>.

<sup>14</sup> See, e.g., Genevieve Plant et al., *Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane*, 377 Sci. 6614 (2022), <https://www.science.org/doi/10.1126/science.abq0385>.

<sup>15</sup> See, e.g., Daniel H. Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8 Env't Sci. Tech. Letters 567 (2021), <https://pubs.acs.org/doi/abs/10.1021/acs.estlett.1c00173>.

<sup>16</sup> David R. Lyon et al., *Concurrent Variation in Oil and Gas Methane Emissions and Oil Price During the COVID-19 Pandemic*, 21 Atmos. Chem. Phys. 6605 (2021), <https://acp.copernicus.org/articles/21/6605/2021/>.

Response II-17-31: See Section XI.H.2 of the preamble to the final rule for a discussion on the final requirements related to monitoring combustion control devices during OGI and AVO inspections.

#### **17.1.7 Other**

Comment: Commenter (3818-AXPC) requests that EPA clarify its intent regarding a potential semiannual reporting requirement for control device monitors. In the supplemental proposal, EPA proposes that operators prepare a site-specific control device monitoring plan that addresses the "[o]ngoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f)," among other things.

40 CFR 60.7(c) contains a requirement to submit a semiannual report for continuous monitoring devices subject to new source performance standards. This semiannual report must include information relating to excess emissions and monitoring system performance. The commenter states that it can find no analysis of the impact of semiannual reporting under 40 CFR 60.7(c) and requests that EPA clarify that it does not intend for operators to submit these semiannual reports. To the extent EPA intends for operators to submit these semiannual reports, the commenter requests that EPA include its evaluation of the impact of semiannual reporting in its regulatory impact analysis and clarify what information it intends to receive. For example, 40 CFR 60.7(c) and (d) require reporting of excess emissions data obtained from continuous emissions monitoring systems; however, other than for some sweetening units, EPA's supplemental proposal does not require continuous emissions monitoring. Similarly, 40 CFR 60.7(f) contains recordkeeping requirements that apply only to continuous emissions monitors. Considering the already robust recordkeeping and reporting requirements contained in EPA's supplemental proposal, the commenter believes it would be inappropriate and unnecessary to apply these semiannual reporting and recordkeeping requirements to monitoring devices that are not continuous emissions monitors – e.g., combustion device pilot monitors.

Response II-17-32: EPA notes that §60.7 applies to all continuous monitors – both continuous emissions monitoring systems and continuous parameter monitoring systems. However, because deviation reporting for continuous monitoring systems is already included in the annual report required under §60.5420b and §60.5420c, we have determined for the purposes of NSPS OOOOb and EG OOOOc it is unnecessary to require the §60.7 semiannual reports. As such, in the final rule, we have removed the references to §60.7(c), (d), and (f) from the monitoring plan requirements in NSPS OOOOb and EG OOOOc.

Comment: Commenter (2218-TCEQ) requests that EPA allow for thermal control of emissions from associated gas from oil well sites (and exempt oil wells with associated sour gas from flaring restrictions). The TCEQ believes that further consideration should be given to allow for control methodologies for these sites similar to other oil and gas facilities, including thermal control using flares which typically represent less than 100% destruction efficiency. The commenter suggests that EPA also allow for operations at the oil wells to continue with thermal control during the analysis by the professional engineer and implementation of the recovery strategy. Due to safety concerns, the commenter believes that the EPA should explicitly exempt oil wells with associated sour gas from the recovery requirements. The corrosive nature of sour



gas greatly restricts available recovery options. Requiring a demonstration by a professional engineer that recovery and reuse are not feasible for oil wells with associated sour gas may place a significant burden on smaller operators. The commenter also suggests that EPA should also point to available and successfully implemented recovery strategies for sour gas.

Response II-17-33: For responses to comments related to control of emissions of associated gas, see Volume II, Chapter 6. Additionally, see discussion in response II-6-10, which specifically addresses this topic.

Comment: Commenter (2399-GPA) requests clarification regarding devices with pressure regulators. Because many flares and enclosed combustion devices rely on a pressure regulator, the commenter would like to ensure that the emissions from any pilot, sweep, or purge gas required to prevent flame back flow will be exempt from any operating limit associated with control requirements. The commenter believes that EPA intended such an exclusion while affected facility gas was not directly going to the flare. However, facilities may route affected gas to the fuel system which may end up at the flare as purge or pilot gas. Because many gathering and boosting facilities use field gas or waste gas as part of their fuel system to ensure these gases are not vented to atmosphere, the commenter believes those streams should be exempted from the requirements while only these gases are going to the flare. This is important when pressure regulators are used on regulated streams to ensure flow minimums are met. Further, the commenter would like EPA to clarify and confirm that a pressure regulated flare does not need to meet the control requirements when using sweep and pilot gas. Sweep gas is needed to ensure the flare does not burn back into the stack and helps to prevent dead leg corrosion. Consistent with rules governing similar equipment at refineries,<sup>17</sup> the commenter suggests that the EPA should likewise confirm that this practice is exempt from any operating restrictions in a final rule.

Response II-17-34: EPA agrees with the commenter that, during periods when gases, vapors, and fumes are not vented from the affected facility to a control device, operating limits, such as the flare gas net heating value, do not apply.

## **17.2 Flares**

### ***17.2.1 General Support for Flaring Requirements***

[**Note:** For specific comments on requiring flaring as a control option for differing emission sources (e.g., oil wells with associated gas, storage vessels), see related emission source Chapters of this document.]

Comment: Commenters (1655-AAP, 2269-Private Citizen, 2347-Clarke Valve, 2394-Earthworks, 2425-TCS, 2447-CALH, 2462-Private Citizen, 2541-AAP) urge the EPA to not only discourage, but to prohibit the practice of flaring in non-emergency cases. The commenters believe that banning this practice will provide further reductions in emissions of both greenhouse

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<sup>17</sup> See, e.g., 40 CFR 63.670(b) (pilot flame presence required only “when regulated material is routed to the flare”); 63.670(c) (visible emissions restriction only “when regulated material is routed to the flare”); 63.670(d) (flare tip velocity requirements apply “whenever regulated material is routed to the flare for at least 15 minutes.”).

gasses (GHGs) and other airborne pollutants, improving air quality in the immediate and long-term.

Commenter (2462-Private Citizen) suggests EPA should allow flaring only for safety reasons and should require written justifications when flaring occurs. Further, the commenter suggests that flares should be monitored continuously, with real-time results available online to nearby residents so they can avoid exposure to toxics.

Response II-17-35: EPA agrees with the commenter that standards should limit or discourage flaring where possible. EPA also agrees that the complete elimination of flaring of associated gas in all situations is not practical, for safety and other reasons. EPA therefore has designed our final rule to prohibit long term flaring for some sources, while leaving options open to other sources to manage associated gas in ways that makes flaring less frequent. See sections X.F.2 and XI.F.2 of the preamble to the final rule for discussion of the final standards on associated gas from wells for NSPS OOOOb as well as the final presumptive standards for EG OOOOc. In the context of existing sources of associated gas, EPA included a subcategory in the final emission guidelines for sources that produce 40 tpy or less of methane that allows those sources to flare routinely. In accordance with the final EG OOOOc, existing sources that produce over 40 tpy of methane may flare if other options are technically infeasible. See §60.5377c for model rule text in EG OOOOc on this point. As alluded to above, EPA's final standards also allow for flaring where circumstances are not routine and flaring is the reasonable option for interim periods, such as malfunctions or interruptions in sales line service. See §60.5377b and §60.5377c for specific regulatory language on this requirement. EPA believes that these various allowances for flaring address the bulk of commenters' concerns.

EPA also notes that methods have not yet been developed for continuously monitoring the emissions streams from flares, and as such, we cannot require such information to be publicly posted.

Comment: Commenter (2460-Private Citizen) states that flaring is meant to be a cure for the problem of venting gas, but it is a wasteful, imperfect cure that causes many problems of its own. They explain that the release of methane that isn't totally combusted in the flame; release of volatile toxic/carcinogenic compounds, formation of soot particles and release of un-combusted methane when a flare is accidentally extinguished by wind, experiences uneven gas flow or has some other system malfunction. The commenter adds that flaring is wasting as much as 10 percent of natural gas worldwide, which results in large-scale production of CO<sub>2</sub> without any useful work being done. The commenter recommends that flaring be severely restricted to minimize usage. Instead of flaring, the commenter suggests the goal should be to capture as much methane as possible from processing and from leaks in pipelines, compressor stations and processing facilities. The commenter explains that methane that is captured can be monetized to more than pay for the equipment required to capture methane emissions.

Response II-17-36: EPA is requiring monitoring of pilot lights, heating value, gas flow, and visible emissions from combustion control devices in the final rule. We are also requiring owners and operators to assess combustion control device operation during AVO and OGI inspections. EPA expects these monitoring requirements to reduce the instances of unlit or underperforming

combustion control devices and ensure that these devices achieve the required control efficiency on an ongoing basis.

For responses to comments related to flaring of associated gas, see Volume I, Chapter 17 and Volume II, Chapter 6.

Comment: Commenter (2409-BP) unequivocally supports EPA's effort to eliminate routine flaring and minimize non-routine flaring, and is pleased EPA is further soliciting comment on control device efficiency and operation of flares. In April 2021, the commenter announced its intention to eliminate routine flaring in its U.S. onshore operations by 2025. To achieve this goal, all newly constructed bp operated well sites are tied into gas delivery pipelines from start-up, and the commenter does not bring new wells online unless the wells have access to a gas pipeline. The commenter also reports that it is also building centralized production facilities and converting legacy wells from high pressure systems to low pressure gas gathering systems to tie in more of their existing production into centralized facilities.

In the commenter's (2409-BP) January 2022 comment letter on EPA's previous proposal, the commenter reports that they noted that since taking operational control over BHP's oil and gas assets in the Texas Permian Basin in 2019, they have reduced flaring intensity in the basin from 16 percent in the fourth quarter of 2019 to less than one percent today. The commenter notes this downward trend has continued since those previous comments, which is attributable to the actions and investments taken to address the efficiency and operations of flares. Notably, the commenter states they install air assist to improve the combustion efficiency of flares (above 95 percent control efficiency as proposed in 40 CFR 60.5377b(b)), and thermocouple sensors integrated with automation on all flare stacks to notify the operations teams of unlit flares. Further, the commenter provides that all their flares have auto-ignitors to remotely reignite flames that may have extinguished.

Response II-17-37: EPA acknowledges the commenter's support and the information provided by the commenter.

Comment: Commenter (2249-NACAA) supports the extension of requirements for reducing flaring equipment malfunctions and limitations on flaring where alternatives are available and recommends engagement with affected agencies to ensure that final rules offer agencies implementation flexibility that considers safety and technical feasibility.

Response II-17-38: EPA acknowledges the commenter's support. EPA remains committed to working with delegated state agencies as they implement NSPS OOOOb. Additionally, EPA is committed to working with states as they develop and submit state plans to the Agency for review for purposes of implementing EG OOOOc. EPA strives to maintain consistency in its collaboration with states to ensure that implementation will be uniform.

### ***17.2.2 General Opposition to Flaring Requirements***

[**Note:** For specific comments on requiring flaring as a control option for differing emission sources (e.g., oil wells with associated gas, storage vessels), see related emission source Chapters of this document.]

Comment: Commenter (2353-CrownQuest) is concerned that EPA is proposing significant new regulations on flares, which the commenter believes are based on the operation of flares at more complex sites. The commenter explains that most flares on oil and gas sites are used periodically for short periods, like hours or days, and when there are upset conditions, such as unplanned or planned downtime from the midstream provider. While these regulations may be reasonable from a cost versus emission standpoint for a large facility that flares continuously for over six months, the commenter states that they are an extremely expensive and burdensome requirement for facilities that may flare 1,000 one thousand cubic feet (MCF) a year over a few days, states the commenter. The commenter is concerned that the EPA did not consider individual circumstances and instead applied a large continual flaring standard to seldom and periodic emissions control equipment. Instead, the commenter urges EPA to evaluate and promote new flare designs that can work more efficiently, rather than apply burdensome operating standards that are highly expensive for minimal emission reduction. The commenter contends that while smoking flares are good propaganda for oil industry malfeasance, it is a mischaracterization of most flaring and not a BSER.

Commenter (2353-CrownQuest) states that much data is available on flaring intensity (i.e., flaring relative to gas production in oil fields or MCF gas flared/MCF gas produced), like the leak survey data available through The Environmental Partnership.<sup>18</sup> The commenter believes that this data from operators could be very beneficial in providing a BSER. The commenter states that operators implemented practices to reduce flare volumes, promoted the beneficial use of associated gas, and calculated flare intensity to demonstrate progress.

Response II-17-39: The required BSER for various affected facilities in NSPS OOOOb and EG OOOOc is 95 percent control. As such, owners and operators must meet 95 percent control of emissions from affected or designated facilities subject to those standards at all times. The testing and monitoring requirements in the rule are designed to ensure that the control devices used on affected or designated facilities are in continuous compliance with this standard. EPA notes that NSPS OOOOb and EG OOOOc do not dictate which control device must be used on sources. Owners and operators should choose the type of control device that makes the most sense for their site from a technical and economic standpoint.

### ***17.2.3 Flare Design, Operation, and Monitoring Requirements***

#### ***17.2.3.1 Support for Flare Monitoring Requirements***

Comment: Commenter (2305-Williams) is supportive of many of the flare monitoring requirements. The commenter supports applying 40 CFR 60.18(b) minimum inlet gas NHV requirements and maximum flare tip velocity requirements to conventional flares at processing

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<sup>18</sup> <https://theenvironmentalpartnership.org/>.

plants. The commenter explains that gas plant flares can operate over a range of operating conditions and control numerous emissions sources regulated by multiple EPA programs (e.g., NSPSs OOOO/OOOOa, Kb, HH). The commenter acknowledges that proper monitoring and control of inlet gas heat content and flare tip velocity is important in ensuring  $\geq 95$  percent control of VOCs and methane in vented gas from the NSPS OOOOb/EG OOOOc emissions sources routed to the flare. The commenter supports the EPA's decision to have control devices meet a 95 percent VOC and methane emission reduction requirement instead of the 98 percent reduction proposed in the November 2021 proposed framework.

Commenter (2305-Williams) is supportive of EPA's proposal to include special provisions in NSPS OOOOb/EG OOOOc which require a minimum NHV of the inlet gas to the flare of 800 Btu/standard cubic feet (scf), and an exemption from the maximum velocity requirements in 40 CFR 60.18(b). The commenter agrees with EPA, as stated in the preamble, that maximum velocity requirements for pressure-assisted flares are not needed since flare tips installed on these flares provide good mixing of the flared gas with surrounding air at velocities that exceed maximum flare tip velocities in 40 CFR 60.18(b).<sup>19</sup>

Commenter (2305-Williams) agrees with EPA's proposed 1-hour monitoring and averaging requirement for inlet gas NHV for conventional flares and pressure-assisted flares at processing plants. The commenter agrees with EPA's proposed 1-hour monitoring and averaging requirements for inlet gas volumetric flow rate on conventional flares.

Response II-17-40: EPA acknowledges the commenter's support.

#### 17.2.3.2 Recommendations for Flare Monitoring

Comment: Commenter (2460-Private Citizen) notes that flaring causes the release of volatile toxic/carcinogenic compounds, formation of soot particles, and release of totally uncombusted methane when a flare is accidentally extinguished by wind, and that failures of flares are too common. The commenter suggests that in cases where flaring absolutely must be used, every flare should be equipped with an alarm that will provide instant notification to onsite staff so that immediate action can be taken to remedy the situation.

Response II-17-41: Based on the data received in response to the December 2022 Supplemental Proposal (see for example comment II-17-30), EPA is concerned by the incidence of unlit flares in the oil and natural gas sector. To address this issue, in the final rule, we have added a requirement for alert systems to notify the nearest control room when a pilot light is no longer lit. We believe that this requirement will reduce the instances of inefficient flaring.

Comment: Commenter (2248-NDPC) explains that some states allow for combustion devices other than those that meet 40 CFR 60.18. The commenter explains that some wells and storage tanks do not produce enough gas to support the minimum flow rate as specified in 40 CFR 60.18 and that in these cases, where the gas flow rate from a well can't support an engineered flare without pilot and or assist gas, the best practice is to use a flare that has a lower destruction efficiency with an auto-ignitor that sparks every few seconds. Furthermore, even facilities with

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<sup>19</sup> Supplemental Proposed Rule, 87 Fed. Reg. at 74,796.

large gas flow rates will have brief periods of time when the gas flow is very low or when gas content temporarily contains inerts, especially on startup or shutdown of the facility, states the commenter. In these cases, the commenter believes that combusting the gas is better than venting it, and the temporary periods of less than 95 percent destruction should not be considered violations. If the EPA requires flares that meet 40 CFR 60.18 with no exceptions, the commenter warns that additional gas will need to be brought onsite to make up the minimum flow rate which would increase emissions, and in these cases, operators may be incentivized to vent the temporary emissions that do not meet the criteria for 95 percent destruction.

Response II-17-42: NSPS OOOOb and EG OOOOc do not mandate the use of flares. The rules only specify a particular control efficiency, not a particular type of control device. Flares or other combustion devices may not make the most sense economically or from a control standpoint in all situations, particularly for control of low, intermittent flow streams. Additionally, the rule allows for combustion control devices other than flares, as long as the control device meets the requirements outlined in the rule.

Comment: Commenter (2440-NNS) is concerned that monitoring of the flare pilot is inadequate since there are many reported instances of unlit flares despite adequate pilots. The commenter explains that this can occur when methane concentrations are outside of the flammable range. Monitoring of methane emissions from the flare is a more direct means of detecting and quantifying emissions, and the commenter encourages the EPA to also allow continuous monitoring technology solutions as a BSER for flare monitoring.

Response II-17-43: The commenter did not provide additional information to support the fact that having a lit pilot flame will not ensure destruction of methane. We also note that EPA is requiring monitoring of flare gas flow rate to ensure that the flow of gas does not overwhelm the flare flame.

Currently, there are no standardized test methods to continuously monitor the emissions from a flare. However, in the final rule, we have developed a pathway to allow for this technology to be implemented when such a method is available.

Comment: Commenter (2305-Williams) believes the proposed alternative to continuous inlet gas flow monitoring is overly restrictive. The commenter is concerned that the proposal, to require a demonstration that the maximum pressure in a flare header will never cause an exceedance of maximum flare tip velocity, is impractical for a flare that is used for both normal process control and emergency control. Instead, the commenter contends that the demonstration should be required to show that the maximum pressure in a flare header would never cause an exceedance of maximum flare tip velocity during normal facility operating conditions.

Response II-17-44: EPA disagrees with the commenter. Owner and operators must be in compliance with the requirements of the rule during all times. Flares must be able to achieve 95% control at any time that an affected facility is routed to the flare. There is no assurance that a flare would achieve the required control efficiency if it exceeded the maximum flare tip velocity allowed in the General Provisions of 40 CFR part 60. Owners and operators may install a flow meter to continuously monitor the flow of gas to the flare to demonstrate compliance with the

maximum flare tip velocity requirement if calculations cannot be used to demonstrate compliance.

Comment: Several commenters (2248-NDPC, 2305-Williams, 2326-AXPC, 2353-CrownQuest, 2399-GPA, 2428-API) are concerned with the NHV monitoring provisions for flares. Commenter (2305-Williams) states that the initial demonstration, to show that the NHV of a gas stream is always below the required NHV in 40 CFR 60.18(b), is unnecessarily burdensome. The commenter points out that while the proposed NSPS OOOOb/EG OOOOc Rules require a minimum of 200 gas sample analyses over a 10-day period, the Refinery Flare Rule<sup>20</sup>, only requires daily sample analyses for 14 days (14 samples in total) to make this same demonstration. The commenter suggests that EPA require a 10-day test period with one sample every 6 hours, for a total of 40 sample analyses.

Commenters (2248-NDPC, 2305-Williams, 2326-AXPC, 2353-CrownQuest, 2399-GPA, 2428-API) suggest that the proposed minimum NHV demonstration alternative to continuous NHV monitoring should be simplified, because the NHV of vent streams from affected facilities is typically fixed or well above the minimum NHV requirements. Commenter (2428-API) explains that these vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a NHV of approximately 900 Btu/scf, which is 450 percent, 300 percent, or 112 percent of the minimum NHV requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

Commenter (2428-API) questions EPA's justification for the sampling campaign "to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution." The commenter states that EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum NHV and the commenter maintains that such a large sampling set is unnecessary when the NHV of vent streams from affected facilities is typically well above the minimum NHV requirement.

Commenter (2428-API) states that vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, the commenter states that natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"<sup>21</sup> used in EPA's Supplemental Background Technical Support Document (TSD) also suggests NHVs well above the required minimum, explains the commenter. The commenter states that gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. The commenter maintains that, even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum NHV.

Commenter (2428-API) also points out that vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical NHV of 2,000 Btu/scf or more, which is 1,000 percent, 667 percent, or 250 percent of the minimum NHV requirement of

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<sup>20</sup> See 40 CFR §63.670(j)(6)(D).

<sup>21</sup> EPA-HQ-OAR-2010-0505-0084.

200, 300, or 800 Btu/scf, respectively. The commenter states that the addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum NHV, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Commenter (2428-API) states that vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. The commenter notes that both situations could have high carbon dioxide (CO<sub>2</sub>) content which would lower the NHV, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, the commenter proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of NHV.

Commenter (2428-API) states that since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net NHV monitoring, and demonstration alternative are economically unreasonable. The commenter explains that calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of \$164,000 to \$245,000 and these monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum NHV demonstration alternative, the commenter reports that the cost is expected to be \$250,000 or more per demonstration. The commenter summarizes that the cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of \$250,000 to \$275,000 while the cost of 200 hourly samples is estimated at a total of \$300,000 to \$400,000 with an average cost per sample of \$1,500 to \$2,000 including shipping and analysis.

As an alternative, commenter (2428-API) proposes the following to provide operators the necessary flexibility to comply with NHV requirements:

- The 10-day demonstration should be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with 40 CFR 60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or 40 CFR 60.18 assessment demonstrates that the NHV is at least 150 percent of the applicable minimum value (i.e., NHV of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), NHV monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150 percent of the applicable minimum NHV, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).
- If an initial or subsequent sample does not meet 150 percent of the minimum NHV, operators should have the option to conduct a more extensive sampling event with a lower threshold. The commenter proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable



NHV demonstration under the Refinery MACT<sup>22</sup>. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120 percent of the applicable minimum NHV requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120 percent of the applicable minimum NHV, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, NHV monitoring, or demonstration alternative should not be required if operators demonstrate that the NHV is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit<sup>23</sup>. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum NHV is being met.

Commenter (2326-AXPC) also points out that most applicable vent gas streams are consistently above applicable minimum NHV limits. Particularly for upstream facilities, the commenter states that these vent gas streams are typically high in methane, ethane, and VOC content – typically 95+ percent, meaning the NHV of these streams is usually at or above 1,000 Btu/scf, and often much higher. Referencing the proposed rule, the commenter states the highest NHV low limit for an enclosed combustion device or flare is 800 Btu/scf, which is significantly below the expected NHV for most vent gas streams and limited to pressure-assisted devices. The commenter adds that non-pressure assisted flares and ECDs are subject to minimum NHV limits of 200 – 300 Btu/scf, which is well below the typical NHV of an oil and gas vent stream. In addition, they note that, unlike a refinery, operators do not use inert gases that would reduce the inherently high NHV of a vent gas stream. Thus, according to the commenter, there is little risk, and in many cases no risk, that vent gas streams will fall below the minimum NHV at any time, and certainly not great enough risk to warrant costly and onerous continuous NHV monitoring.

Commenter (2326-AXPC) suggests that engineering methodologies (*e.g.*, engineering simulation software) can accurately estimate the heat value of vent gas streams where a representative analysis serves as the basis for the estimation. The commenter explains that these data, combined with operating parameters and production, will provide an accurate estimate of heat value as well as vent gas volume through the use of long understood equations of state – *e.g.*, Peng-Robinson, 1976. The commenter points out that these methods are used for permitting and are a method listed in 40 CFR 98.233 “[o]nshore production and onshore petroleum and natural gas gathering and boosting storage” Calculation Method 1 for Subpart W Greenhouse Gas estimations and therefore, they believe that the EPA should allow operators the option to use engineering methodologies to demonstrate a vent gas stream will remain above the minimum NHV limit.

To address these issues, commenter (2326-AXPC, 3818-AXPC) proposes that EPA allow operators to demonstrate the inlet stream to a combustion control device meets the applicable minimum NHV limit requirement by using a pressurized liquids analysis in combination with

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<sup>22</sup> 40 CFR 63.670(j)(6).

<sup>23</sup> 40 CFR 63.772(b)(2)(i).

engineering software. Under this approach, explains the commenter, the operator would pull a pressurized liquids sample from a separation vessel, or use a representative pressurized liquids sample, and input the sample results into engineering software configured to estimate with a high degree of accuracy the net. If the engineering analysis demonstrates the NHV is within 200 Btu/scf of an applicable NHV limit, the commenter proposes that the operator must then comply with the proposed NHV continuous monitoring requirements or the alternative to continuous NHV monitoring. The commenter proposes 200 Btu/scf, as this value exceeds the 20 percent cushion of the highest potentially applicable NHV limit EPA that notes as being “well above the threshold.”

Regarding the alternative NHV demonstration, commenter (2326-AXPC) supports API’s proposed revisions which would require a minimum of two (2) hourly samples or two (2) hours of continuous monitoring per day for seven (7) days for a total of 14 samples.<sup>24</sup> The commenter believes this method is sufficient to demonstrate the anticipated NHV will remain above the applicable minimum NHV limit.

Commenter (2399-GPA) states that compressor station and gas processing plant waste streams generally have a NHV that far exceeds the minimum values required under the supplemental proposal. The commenter explains that waste gas streams routed to control devices at midstream sources are largely comprised of natural gas and field gas, meaning that these streams are typically above 1,000 Btu/scf. Continuous monitoring requirements, and requirements to perform 10-day tests on control devices for storage tanks, pneumatic pumps, and compressor vents are unnecessary, imposing burdens and costs without any benefit, states the commenter. Instead, the commenter requests that EPA allow owners and operators to perform and maintain a design evaluation to ensure that waste gas streams will consistently exceed minimum NHV requirements. The commenter states this would be similar to that provided in proposed 40 CFR 60.5413b(c) for condensers and carbon absorption units, as well as for combustion device maximum flow rates in proposed 40 CFR 60.5417b(d)(1)(viii)(D).

As an alternative, if a design evaluation is not sufficient, Commenter (2399-GPA) proposes that a simplified sampling protocol be allowed for exempting a control device from continuous heat content monitored by allowing for samples to be taken twice a day for seven days. The commenter believes that such sampling would demonstrate that streams have a relatively constant NHV well exceeding the minimum requirements.

Commenter (2248-NDPC) is concerned with the monitoring requirements of vented gas to determine the NHV and does not believe it is warranted. The commenter explains that operators in North Dakota are required to pull samples and have them analyzed for the constituents and properties and one of the properties that is analyzed is NHV (by GPA 2172). The commenter explains that they reached out to one of the laboratories that collect and analyze samples of associated gas and flared gas in North Dakota, and the lab reported that out of 7,774 gas samples collected and analyzed from 2020 through 2022, the average NHV was 1,459 Btu/scf, while the maximum and minimum values were 1,007 and 2,846 Btu/scf.

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<sup>24</sup> API Supplemental Proposal Comments § 5.6.4.

Commenters (2254-PBPA, 2353-CrownQuest) are concerned about the burden to continually measure heat value. The commenter states such equipment only exists in labs, and there is no available application in the field. The commenter explains that the heat value is generally fixed at oil and gas locations as the oil and gas are not processed but only separated. The commenter believes that the proposed 10-day minimum NHV demonstration is too onerous to be a viable alternative to continuous NHV monitoring. The commenters report that this minimum NHV demonstration must be feasible because calorimeters and other analyzers may be cost prohibitive, states the commenters.

Commenters (2254-PBPA, 2353-CrownQuest) point out that the proposed demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare. The commenter states the minimum cost of a 10-day continuous monitoring effort conducted by a third-party vendor is a \$250,000 estimation and the cost per hourly sample, including shipping and analysis, is estimated at \$2,000 each, or \$400,000 total. The commenter contends that this level of sampling, recordkeeping, and reporting is not indicative of a BSER, nor did the EPA factor this cost into their analysis.

Commenter (2254-PBPA) stated EPA should permit operators to address compliance through annual gas sampling or modeling, and any performance testing should be based on a single day of testing.

Response II-17-45: See discussion in section XI.H.4 of the preamble to the final rule which details EPA's final standards related to measurement of net heating value for combustion control devices.

Comment: Commenter (2305-Williams) states the primary concern with flares in the oil and gas sector is the discontinuous presence of a flame when gas is routed to the flare. The commenter notes that poorly operated and poorly monitored flares at production facilities have consistently been the target of state enforcement programs focused on preventing VOC and methane emissions to the atmosphere. At compressor stations, the commenter provides condensate storage vessels are the predominant NSPS OOOOb/EG OOOOc affected facilities that are controlled by a flare. The commenter adds that other NSPS OOOOb/EG OOOOc sources like wet seal compressors and gas-driven pneumatic pumps are also located at compressor stations, but to a very limited extent. The commenter suggests that these emissions sources present a different set of circumstances at compressor stations (lower volumes of waste gas) compared to what is experienced at a production site (higher volumes of associated gas).

Commenter (2305-Williams) explain that, for condensate storage vessels, the NHV of the vented gas stream to the flare is sufficiently high ( $> 1,000$  Btu/scf), and the vent rate is sufficiently low, resulting in an actual flare tip velocity below the maximum allowable flare tip velocity allowed in 40 CFR 60.18(b). The higher BTU and lower flare tip velocity will prevent the combustion flame from lifting off the flare tip and burning out. In addition, flares controlling storage vessels that have discontinuous or variable vent streams throughout the year are supplemented with station fuel gas to maintain a minimum NHV to sustain the flare.

Commenter (2305-Williams) continues, given these conditions, the proposed continuous (1-hour) monitoring for volumetric flow rate and NHV of inlet gas stream to the flare is not necessary to ensure proper operation of flares at compressor stations. The commenter recommends the following continuous monitoring framework for flares at natural gas compressor stations as an effective and practically feasible alternative to EPA's current proposal:

- Continuous monitoring for the presence of a flame using a thermocouple, ultraviolet sensor, or infrared sensor.
- Weekly 5-minute observations for visible emissions (smoking). If visible emissions are observed during the 5-minute observation period, then perform a Method 22 test with a 15-minute observation period. A deviation occurs when visible emissions exceed a total of 1 minute in the 15-minute observation period.
- Monthly Method 22 for visible emissions (smoking). A deviation occurs when visible emissions exceed a total of 1 minute in the 15-minute observation period.

Response II-17-46: EPA agrees that the heating value of the vent gas to a flare in this sector is likely to be well above the minimum required heating value. Therefore, the EPA provided a pathway for owners and operators to demonstrate compliance with the heating value requirement through an initial demonstration instead of using continuous monitoring. EPA provided a similar compliance option for vent gas flow to the flare. We are maintaining these pathways in the final rule.

EPA is maintaining the requirements for a continuous pilot light and monthly EPA Method 22 observations in the final rule. See response II-17-7 for information concerning the final requirements for visible emissions observations with EPA Method 22.

Comment: Commenter (2362-EIP et al) states that EPA's proposed averaging times for NHV and flare tip velocity are too long and cannot ensure that flares and other controls achieve 95 percent—much less 98 percent—destruction efficiencies and do not reflect BSER. Instead, 15-minute averaging periods for these two operating limits would constitute BSER and much better ensure destruction of VOCs and methane, states the commenter. The commenter points to recent rulemakings for petroleum refining, ethylene production, and Miscellaneous Organic National Emission Standards for Hazardous Air Pollutants (NESHAP) (referred to as the MON) facilities, where EPA has required flares to comply with operating limits for NHV and flare tip velocity on a 15-minute basis. The commenter states that EPA promulgated these shorter averaging periods to assure that there are fewer periods when flares are not effectively destroying pollutants, as a longer averaging period would allow.

Commenter (2362-EIP et al) considers a short averaging time to be the most appropriate for assessing proper flare performance because flare vent gas flow rates and composition can change significantly over short periods of time. Furthermore, the commenter explains that because destruction efficiency can fall precipitously when a flare is controlling vent gases below (or outside) the proposed operating limits, short time periods where the operating limits are not met could seriously impact the overall performance of the flare. The commenter does not believe that the proposed 1-hour and 3-hour averaging periods for flare tip velocity and NHV, respectively,

would capture the short periods of poor performance that dramatically limit the ability of flares and other control devices to achieve the desired destruction efficiency. Thus, these longer averaging periods do not reflect BSER, states the commenter. Further, the commenter states, EPA has not explained why it has not used shorter (i.e., 15-minute) averaging periods, as it has done in other recent rulemakings. The commenter contends that the EPA's differing treatment of flares and other controls at oil and gas sources as compared to flares at refinery, ethylene production, and MON sources renders the 1-hour and 3-hour averaging periods arbitrary and capricious.

Response II-17-47: EPA disagrees with the commenter. While EPA acknowledges that rules at refineries and chemical plants do require shorter averaging times for monitored flare parameters, the vent gas streams at refineries and chemical plants are expected to vary significantly from the vent gas streams in the upstream oil and natural gas sector. The streams sent to flares at refineries and chemical plants contain an array of compounds, many of which are ringed hydrocarbons, which are harder to destroy than the straight-chain hydrocarbons that make up most of the vent gas streams in the upstream oil and natural gas sector. Additionally, refineries and chemical plants routinely pad tanks with nitrogen blankets. It is not uncommon for the nitrogen from the padding to be swept into the flare gas stream, thus creating situations where the net heating value of vent gas drops to low levels. This is generally not a concern in the upstream oil and natural gas sector. Due to less variability in the vent gas streams, easier to burn vent gas composition, and the expected high heating values of the vent gas streams, EPA does not think it is necessary to require monitoring on a 15-minute basis for these units and is requiring the same averaging time for these flare parameters as for other control device operating parameters.

It is EPA's understanding that the largest issue with flares in the upstream oil and natural gas sector is not the heating value of the vent gas or the flowrate of gas through the flare. The largest issue is the incidence of unlit flares. As such, EPA has included requirements for continuously lit pilot flames and control room alert systems to NSPS OOOOb and EG OOOOc. The owner or operator must verify the flare is lit at least once every five minutes. These requirements should help to resolve instances of unlit flares.

Comment: Commenter (2362-EIP et al) states that EPA must require direct NHV monitoring at all oil and gas flares and combustion devices on a continuous basis. The commenter states they believe that EPA correctly recognizes that the NSPS general provisions mandate that the agency establish monitoring for the general provisions' NHV and flare tip velocity operating limits, especially since the general provisions themselves contain no monitoring requirements for those two limits. The commenter believes that EPA also correctly concludes that the current operating and monitoring practices and requirements for well sites and centralized production facilities are not adequate to ensure flare control systems are operated efficiently—and also notes that establishing required monitoring for the NHV and flare tip velocity operating limits is especially important because the proposed rule states “recent studies suggests [sic] that 10 percent of flares in the Permian basin are either unlit or are only burning a portion of the gas sent to the flare.”

Commenter (2362-EIP et al) states that to correct this deficiency for NHV monitoring, EPA proposes that flares and enclosed combustion devices monitor the heating value through a continuous parameter monitoring system, such as a calorimeter. The commenter is concerned,

however, that EPA proposes to allow these control devices to take advantage of an alternative, by allowing the owner or operator conduct a ten-day initial assessment to demonstrate that the vent gas NHV “consistently exceeds” the required minimum value, instead of continuous monitoring. The commenter adds that they are also concerned with the proposal to allow owners and operators to determine “[i]f process operations are revised that could impact the NHV of the gas sent to the enclosed combustor or flare,” in which case a “re-evaluation” of the gas stream must be performed.<sup>25</sup>

Commenter (2362-EIP et al) believes these “loopholes” do not reflect BSER and cannot ensure that flares and other control devices destroy 95 percent—much less 98 percent—of VOCs and methane. The commenter adds that these loopholes do not constitute “provisions stating how owners or operators of flares shall monitor these control devices,” as required by 40 CFR 60.18(d); instead, they contend that the loopholes are provisions stating how owners and operators can avoid monitoring.

Commenter (2362-EIP et al) suggests that ten days of sampling cannot capture the variability of gas streams’ NHVs at oil and gas facilities, due in part to compositional variability, inert gases, and impurities in gas streams. Hourly samples taken over 10 days cannot capture the lowest heating values of vent gas streams at oil and gas facilities at later dates, states the commenter. Put another way the commenter states, ten days of sampling could yield NHVs that are much higher than the heating values of gas streams later present at oil and gas facilities, which would in turn give the false impression that these facilities are meeting NHV operating limit when in fact they are not. The commenter is concerned that the alternative will mean that oil and gas flares and other combustion devices will release much more VOCs and methane than the devices would if they were all required to directly monitor NHV.

Commenter (2362-EIP et al) points out that EPA claims 10 days of sampling will “provide a large sampling set by which to assess the variability of the vent gas . . . and to adequately characterize the tails of the distribution”—and that a “20 percent cushion” is a “reasonable minimum value for ‘well above the threshold.’” This, however, according to the commenter, is simply not the case given the possible variability of gas streams at oil and gas facilities—and especially given that EPA is allowing up to ten percent of samples to be less than 1.2 times the required minimum NHV. Further, the commenter is concerned that leaving it up to owners and operators to determine “[i]f process operations are revised that could impact the NHV of the gas sent to the enclosed combustor or flare” means that flares and other control devices are even less likely to meet the NHV operating limit—and thus are less likely to achieve proper destruction of VOCs and methane.

Commenter (2362-EIP et al) questions EPA’s claims that the alternative provisions will provide ample cushion to capture the underlying variability of gas streams’ heating values. The commenter states that EPA has not gathered or cited to any data showing this is the case, which EPA must do to comply with its statutory duties under CAA section 111. Thus, the commenter believes that the EPA has not rationally or lawfully considered the variability of gas streams’ NHVs. They contend that the EPA has not rationally explained—and has no rational basis for—allowing flares and other combustion devices to avoid direct NHV monitoring. The commenter is

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<sup>25</sup> Proposed 40 CFR 60.5417b(d)(1)(viii)(C)(5), 60.5417c(d)(1)(viii)(C)(5).

further concerned that EPA has failed to consider an important aspect of the problem in failing to look at the relevant data and examine whether there might be variability that would prevent this loophole from ensuring proper destruction efficiencies. To the extent EPA is basing its decision to allow this monitoring loophole on purported cost savings associated with the loophole, the commenter warns that also renders the agency's decision arbitrary and capricious. The commenter reports that the costs of installing and operating a calorimeter or other relevant monitoring device for NHV are relatively low, and these monitors are cost-effective—especially given that EPA's proposed alternative cannot ensure the proper destruction of VOCs and methane and given the large emissions decreases that would result if EPA required all flares and other controls to continuously monitor NHV.

Commenter (2362-EIP et al) states that the alternative to continuous monitoring is also contradicted by findings that EPA has made regarding the great variability of gas compositions over short periods of time and the resulting dramatic effects on combustion efficiencies<sup>26</sup>. The commenter states that the proposed alternative would not capture those periods when the heating values of gas streams fall significantly over short periods of time—and would thus seriously impact the overall performance of flares and other controls at oil and gas facilities. The commenter urges EPA to not allow oil and gas facilities to avoid direct NHV monitoring through ten days of sampling. Instead, they contend, to capture the variability of gas streams' NHVs and ensure adequate destruction of VOCs and methane, EPA must require direct NHV monitoring at all oil and gas flares and combustion devices.

Response II-17-48: See discussion in section XI.H.4 of the preamble to the final rule which details EPA's final standards related to measurement of vent gas net heating value.

Comment: Commenter (2362-EIP et al) questions EPA's proposal to monitor NHV of the vent gas instead of NHV in the combustion zone. The commenter references EPA's discussion in the supplemental proposal, where EPA explains why the agency does not include requirements from recent NESHAP amendments for the refining and chemical sector, where EPA has required flares to meet an operating limit for the NHV in the combustion zone—instead of the heating value of the vent gas. The commenter explains that EPA's rationale was that “[w]hile this is important for an assisted flare, we anticipate the oil and gas source category predominately will use unassisted flares, because air-assisted flares require electricity and not all sites will have access to electricity.” The commenter also reminds EPA of their rationale that the general standards from 40 CFR 60.18—which only focus on the heating value of the vent gas—are sufficient because, for unassisted flares, the “heat content of the gas at the flame is not diluted by an assist stream of gas or air,” but that EPA nevertheless “requests comment on the universe of unassisted and assisted flares in the oil and gas sector.”

Commenter (2362-EIP et al) suggests that they believe it is EPA's duty, however, to gather the necessary data—before issuing a proposed rule—to determine whether there are assisted flares in the oil and gas sector. The commenter suggests that EPA could easily gather this data through its information collection authority under CAA section 114, 42 U.S.C. § 7414(a)(1), through reviewing air permits for oil and gas facilities, and/or by consulting with state permitting

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<sup>26</sup> The commenter cited to the proposed CAA section 112(d)(6) review for Miscellaneous Organic Chemical Manufacturing. See 84 FR 69203.

agencies. The commenter states that EPA also could have reviewed information from vendors of flaring equipment to determine whether vendors offer air- or steam-assisted flares. By way of example, the commenter provided information from four vendors who offer air assisted flare systems to oil and gas producers, along with gas assisted smokeless flares; one of which offers a flare system designed to limit the overuse of steam. Therefore, the commenter does not believe it suffices under the statute that EPA “anticipates” that oil and gas facilities will likely use unassisted flares. Further, they state that the agency seems to concede that some oil and gas flares likely are assisted: if the oil and gas sector “predominately” uses unassisted flares because “not all” sites will have electricity, that means that some facilities will use assisted flares and will have access to electricity, surmises the commenter.

Commenter (2362-EIP et al) states that the agency’s failure to gather the data necessary to comply with its duties of review and revision under CAA section 111(b)(1)—and duties to promulgate EG under CAA section 111(d)—does not absolve it of complying with those duties (e.g., where appropriate, the agency must revise its standards to require the BSER<sup>27</sup> and EPA “shall prescribe” EG for existing sources in the situations specified by CAA section 111(d)(1)).<sup>28</sup> If there are assisted flares in the oil and gas sector, the commenter believes EPA’s refusal to require improved flare standards for NHV in the combustion zone would violate EPA’s duties under CAA section 111 and would be irrational—especially given that even EPA recognizes that meeting a combustion zone operating is necessary to ensure proper destruction efficiencies at assisted flares.

For any assisted flares in the oil and gas sector, commenter (2362-EIP et al) urges EPA to require those flares to meet an operating limit for the NHV in the combustion zone, as EPA has done for flares at refineries and petrochemical sources. As EPA properly found in its 2014-15 refinery NESHAP rulemaking, many studies have shown that the general flare provisions cannot ensure that flares achieve 98-percent destruction efficiencies, states the commenter.<sup>29,30</sup> Earlier, in 2012, EPA published an Enforcement Alert<sup>31</sup> regarding flaring violations, in which the agency recognized that certain needed parameters affecting the efficiency of flares are not captured within the general requirements, including maintaining the appropriate steam-to-vent-gas ratio and ensuring that the heating value of combustion zone gas is high enough to maximize combustion efficiency, states the commenter. The commenter summarizes that the Enforcement Alert stated that the heating value in the combustion zone gas “is a better indicator of efficiency than the heating value of the Vent Gas alone,” the latter of which the general provisions focus on. And in April 2012, EPA published a report examining “Parameters for Properly Designed and Operated Flares,” states the commenter. The commenter explains that EPA noted that reliance on the NHV of the vent gas—the parameter that the NSPS and NESHAP general flare requirements use” as an indicator of good combustion ignores any effect of steaming. Therefore, the commenter states that to incorporate steaming, a NHV of the combustion zone gas was calculated to include the assist steam.”<sup>32</sup> The commenter states that because complying with an

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<sup>27</sup> See 42 U.S.C. § 7411(a)(1), (b)(1)(B).

<sup>28</sup> See 42 U.S.C. § 7411(d)(1).

<sup>29</sup> See, e.g., 79 Fed. Reg. at 36,905.

<sup>30</sup> See 80 Fed. Reg. at 75,189.

<sup>31</sup> See EPA, EPA Enforcement Targets Flaring Efficiency Violations, Enforcement Alert (Aug. 2012).

<sup>32</sup> See EPA Office of Air Quality Planning and Standards, Parameters for Properly Designed and Operated Flares 3-32 (April 2012).



operating limit for the heating value of the vent gas cannot ensure 95 percent (or greater) destruction efficiency of VOCs and methane by assisted flares, it is appropriate under CAA section 111 to update the flare requirements for any assisted flares to ensure proper destruction efficiencies and to ensure that the standards and EG for any assisted flares reflect BSER. The commenter challenges that the CAA does not excuse EPA from complying with its duties where the agency lacks information. The commenter summarizes that EPA must gather the necessary information here to determine whether there are assisted flares in the oil and gas sector and if there are assisted flares, EPA must require them to comply with an operating limit for NHV in the combustion zone and must promulgate monitoring requirements to ensure compliance with that limit.

Response II-17-49: See discussion in section XI.H.5 of the preamble to the final rule which details EPA's final standards related to assisted flares.

Comment: Commenters (2298-Pioneer, 2305-Williams, 2326-AXPC, 2382-BH, 2399-GPA) have concerns with the use of calorimeters. Commenter (2326-AXPC) states that the use of calorimeters in the upstream oil and gas sector is unproven due to the variable nature of production flowrates results in low and/or intermittent vapor control streams. Current calorimeter technology cannot accurately measure the NHV of these low and/or intermittent streams consistently over time and across varying operating conditions, explains the commenter and in these applications, calorimeters are unlikely to yield accurate or useful data. In addition to the technical concerns, the commenter believes the supplemental proposal will prompt thousands of calorimeter orders that will overwhelm calorimeter supply vendors, resulting in a supply chain crisis, as operators wait months or longer for order fulfillment. The commenter reports that one of the most prominent calorimeter manufacturers in the U.S. estimates current supply can only be met for 6 to 10 units per month at a cost of \$70,000 to \$120,000 per unit (average \$100,000). The commenter is concerned because large operators may have one thousand or more flares that would require monitoring under NSPS OOOOb or EG OOOOc. Further, the commenter explains there would be additional demands on the site infrastructure, such as the use of instrument air systems required to operate the calorimeter. Finally, the commenter points out that calorimeter installation and maintenance require a skilled labor force that currently is insufficient in supply to meet the needs supplemental proposal. The commenter is concerned that it would take years to recruit and train this labor force and that the combination of equipment and labor supply shortages will force operators into a position where compliance is simply infeasible by compliance deadlines.

Commenter (2305-Williams) disagrees with EPA's requirement that only calorimeters can be used to determine the NHV of gas routed to a flare and believes that ultrasonic meters and gas chromatographs should also be allowed. The commenter explains that ultrasonic flow meters are capable of instantaneously measuring the molecular weight (and volumetric flowrate) of gas routed to a flare. The commenter provides that most molecules processed through a natural gas processing plant are straight chain alkane hydrocarbons whose molecular weight (MW) directly correlates to NHV. They add that calibration curves of NHV vs MW can be developed based on laboratory analysis of gas samples vs MW measurements from an ultrasonic meter. The commenter states that if the flare is assisted, digital MW/NHV and volumetric flow rate data can be instantaneously transmitted to a supervisory control and data acquisition (SCADA) system to

regulate air blowers or steam valve actuators and air or steam assist rates can thereby be optimized in real-time to assure  $\geq 95$  percent destruction of VOCs and methane. They request that gas chromatographs also be allowed to determine NHV of the inlet gas to flare because gas chromatographs speciate the hydrocarbon components of a gas stream, enabling the NHV of the gas stream to be calculated as the weighted sum of the individual NHVs of the gas stream's components.

Commenter (2399-GPA) asks that EPA ensure there is an allowance for monitoring options other than a calorimeter, which the commenter states have a high-cost threshold for the expected emissions reductions. The commenter suggests options like gas chromatography and optical spectroscopy should be allowed for compliance purposes. Costs of this equipment can range from \$75,000 to \$100,000 each and for most control devices, the heating value of the gas would consistently be well above the 200 BTU/scf, or 300 BTU/scf, or 800 BTU/scf triggers, making this equipment very expensive for the expected heat content of the gas streams. As currently written, the commenter is concerned that the supplemental proposal exemption option to continuous monitoring requirement would require expensive short-term monitoring to obtain 240 samples and lab analyses, as well as specialized contractors to install and operate those monitors, to exempt a site from the heat content monitoring. With hourly samples taken over a ten-day period, each sampling event would cost approximately \$200,000 per control device due to equipment rental costs and the costs for contractors to be onsite analyzing the data during this period, estimates the commenter. The commenter provides that this issue becomes more complicated when the facility is at a remote location where staff is not there to continuously catch samples or support the testing company analyzing the sample.

Commenter (2298-Pioneer) reports that continuous monitoring of NHV presents inaccuracy issues associated with low or intermittent gas streams due to technological limits. The commenter explains that supply chain issues and operation/maintenance of expensive and highly technical calorimeters which have not been utilized in upstream operations and are unproven to be effective would result in highly inaccurate and useless data recordkeeping and reporting. While the commenter agrees with the potential exemptions available for continuous monitoring, the commenter proposes that EPA allow operators to periodically (i.e., quarterly) sample representative inlet gas streams to demonstrate compliance with any applicable heating value requirement for control devices used to control affected facilities with intermittent or low flow gas streams under this rule.

Commenter (2382-BH) provides that one of the key requirements for flare operation is to maintain NHV<sub>cz</sub> of approximately 270 Btu/scf minimum, typically measured by using a gas analyzer or calorimeter. The commenter explains that their experience is that those instruments are difficult to maintain. They add that field data acquired using flare.IQ<sup>33</sup> indicate that the NHV calculation coming from the sound speed computation method is a suitable alternative for flare gas NHV measurement, and NHV from sound speed is within 3 percent when compared to measurements using a GC or a mass spectrometer. The commenter offers to serve as a technical resource for the agency regarding flare efficiency solutions to support the agency's finalization of the methane rule.

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<sup>33</sup> See <https://www.bakerhughes.com/panametrics/flare-management/flareiq>.

Response II-17-50: EPA agrees that calorimeters are not the only continuous monitoring devices that can be used to assess net heating value. In the final NSPS OOOOb and EG OOOOc, EPA has added gas chromatographs, mass spectrometers, and automated grab sampling systems as additional options for continuously monitoring net heating value. These additional options, along with the sampling demonstration that can be used in lieu of continuously monitoring net heating value, should alleviate the technical and supply chain concerns raised by the commenters. While EPA is aware of optical and ultrasonic meters used to measure flow, we are not aware of these types of systems being used to measure net heating value. We do not have enough understanding of how these systems can be used to monitor net heating value, the accuracy of these measurements, or the limitations of the monitors, and as such, we cannot include them in this action. As allowed by §60.13(i) and §60.5417(d), owners and operators may request approval from the Administrator for alternative monitoring to what is specified in NSPS OOOOb and EG OOOOc; such an application should include adequate information to demonstrate that the requested method can accurately measure the parameter and limitations of the method. Additionally, we have included a pathway in the final rule for owners and operators to request alternative approaches for monitoring combustion control devices. See discussion in section XI.H.6 of the preamble to the final rule which details EPA's final standards related to alternative approaches to combustion device monitoring.

Additionally, see discussion in section XI.H.4 of the preamble to the final rule which details EPA's final standards related to measurement of vent gas net heating value.

Comment: Commenter (2383-BH) states that because it is not possible to control combustion efficiency for unassisted flares, setting a minimum threshold for combustion efficiency is not feasible at this time. The commenter recommends requiring continuous monitoring, reporting and verification. Rather than basing reported emissions on assumptions (e.g., stack is designed to meet xx percent combustion efficiency (CE)), the commenter recommends that reports be based on real time monitoring. Also, they believe with real time monitoring in place, operators may find levers to improve the CE as effective control depends on accurate measurement.

Response II-17-51: The required BSER for various affected facilities in NSPS OOOOb and EG OOOOc is 95 percent control. As such, owners and operators must meet 95 percent control of emissions from affected or designated facilities subject to those standards at all times.

EPA does not yet have standard methods for continuously monitoring combustion efficiency from flares. As part of the final rule for NSPS OOOOb and EG OOOOc, we have implemented a pathway for the use of future alternative technologies in monitoring flares, including those that can continuously monitor control efficiency. See section XI.H.6 of the preamble to the final rule, which discusses this topic.

Comment: Commenter (2414-CM-RMI) states that the December 2022 Supplemental Proposal and existing regulations do not contain provisions to directly validate or verify destruction efficiency, unless a flare is detected as part of the Super-Emitter Response Program. The commenter recommends that EPA remain abreast of studies and data available that would indicate improvements in flare performance based on requirements. Furthermore, the commenter offers suggestions for the pilot flame monitoring alternative to demonstrate that the NHV of the

inlet gas to the flare consistently exceeds the operating limit established in the rule. The commenter believes that the demonstration should be subject to a time- and/or volume-based limitation and should require re-submittals to ensure that original conditions granting such an exception persist.

Response II-17-52: EPA will continue to study available monitoring technologies for flares. As part of the final rule for NSPS OOOOb and EG OOOOc, we have implemented a pathway for the use of alternative technologies in monitoring flares. See section XI.H.6 of the preamble to the final rule, which discusses this topic. Additionally, in the final rule for NSPS OOOOb and EG OOOOc, we have added requirements to re-evaluate the NHV sampling demonstration and the maximum gas flowrate demonstration any time there are changes to the process or control device that may affect these parameters. EPA has also added confirmatory testing of the net heating value every five years for owners and operators who do not continuously monitor the flare gas net heating value. See additional information on the final net heating value requirements in section XI.H.4 of the preamble to the final rule.

Comment: Commenter (2254-PBPA) states EPA assumes all flares at an oil and gas site are used to meet a OOOOb/c performance standard, meaning that all flares would need to meet the monitoring and operational requirements in 60.18, and as such EPA expects owners and operators to verify compliance with 60.18 “where it is determined that a super emitter emissions event is caused by a flare.”<sup>34</sup> But that is not always the case, as some flares may be located onsite for use only in emergency situations. As such, flares associated with a “super emitter emissions event” that are not used to comply with a performance standard should not be required to verify compliance with 60.18.

Response II-17-53: EPA disagrees with the commenter’s assertions of EPA’s expectations. When an owner or operator investigates a super-emitter event, the owner or operator is obligated to review monitoring data from control devices from the affected (or designated) facilities subject to regulation under NSPS OOOO, NSPS, OOOOa, NSPS OOOOb, and EG OOOOc. All of these subparts require compliance with §60.18 when the flare is used to control emissions from an affected (or designated facility). If the flare does not control emissions from an affected (or designated) facility under these subparts, the owner or operator is not obligated to verify that the flare meets the requirements of §60.18 for the purposes of NSPS OOOOb or EG OOOOc.

### 17.2.3.3 BSER (95 Percent)

Comment: Commenter (2362-EIP et al) states that Attachment B to their letter includes a September 2022 article published in Science magazine quantifying emissions of methane from flares in the Bakken, Eagle-Ford, and Permian basins based on multiple aircraft surveys of emission plumes in 2020 and 2021. According to the commenter, the authors estimate that flares in all three basins combined release 538,000 short tons of methane on an annual basis, or about 13.4 million tons of CO<sub>2</sub>e, based on an average destruction removal efficiency (DRE) of 91.1 percent.

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<sup>34</sup> Id. at 74,753-54.

More specifically, the commenter states that the study found that:

- Had all flares been lit and operating at 98 percent DRE, methane emissions should not have exceeded 110,000 short tons per year.
- Flares that were lit when surveyed averaged 95 percent DRE, resulting in annual emissions of 297,000 short tons per year.
- When unlit flares were factored into survey results, the total DRE from all flares (lit and unlit) declined to 91.1 percent, resulting in 538,000 short tons of methane per year.

Commenter (2362-EIP et al) states that due to the heavier molecular weight of complex hydrocarbons, EPA's own analysis assumes that tank batteries and other affected sources release about 4.5 tons of smog-forming VOCs for every ton of methane emitted (see, e.g., Table 4, Chapter 7, of EPA's Supplemental Background and Technical Document (October 2022)). If that is correct, the commenter states that flares in the Bakken, Eagle-Ford and Permian basins would release 495,000 tons of VOCs per year at 98 percent DRE; 1.336 million tons at a 95 percent DRE (based on surveys of lit flares), and 2.42 million tons at the 91.1 percent DRE that includes emission losses from unlit flares. They add that EPA estimates that its proposed rule will eliminate 9.7 million tons of VOCs between 2023 and 2035 and 36 million tons of methane, despite if flares and vapor combustion units will not destroy more than 95 percent of VOC's and methane. Based on the above survey results, the commenter believes that EPA could eliminate more than 10 million additional tons of VOCs and another 2.3 million tons of methane over the same 12-year period if all lit flares actually met the 98 percent DRE that CAA State Implementation Plan (SIP) regulations and permits already require, instead of the average 95 percent DRE the authors of the study found in the survey of lit flares. The commenter states that the emission reductions are much greater if monitoring is sufficient to even reduce the frequency of unlit flares venting 100 percent of the methane and VOCs in waste gases directly to the atmosphere.

Commenter (2362-EIP et al) believes that if EPA insists that 95 percent DRE is BSER for flares and vapor combustion units (VCUs) in states that already require 98 percent, the agency should expect states to seek emission credits based on their more "stringent" standards, which would effectively wipe out all the VOC reductions that EPA claims will result from its rulemaking.

Commenter (2362-EIP et al) suggests that EPA should not be surprised at these results, since the agency has never established the continuous monitoring needed to assure that operators maintain the minimum flow and NHVs that EPA identified as critical to maintaining the 98 percent DRE that EPA established in the 1980's. The commenter warns that emission limits that are not adequately monitored will not be met. The commenter believes it is too late for EPA to decide that 95 percent DRE is the best that can be done almost 40 years later after its public assurances that well managed flares can destroy 98 percent of the organic pollutants in waste gases. The commenter believes that adopting that rollback would create havoc within the regulatory, permitting, and air quality modeling systems that have assumed a 98 percent DRE for so long.

Response II-17-54: As the commenter notes, it is common for flares within the oil and natural gas sector to only achieve 95 percent control. The study cited by the commenter demonstrates

this is the case. As EPA noted in the December 2022 Supplemental Proposal,<sup>35</sup> we determined it would not be cost effective to require the additional monitoring and operational costs that would be necessary to guarantee 98 percent control of emissions. We recognize that some delegated agencies may require stricter control. Cost-effectiveness can vary between different areas of the country, and while something may not be cost-effective in a national rulemaking, it may be cost effective in a regional standard. For example, where electricity is readily available, installation of extra monitoring equipment is not as difficult or expensive, and therefore, higher control efficiencies may be more cost effective.

EPA agrees that unlit flares are an issue within this sector, and we are concerned by the incidence of unlit flares. As such, EPA has included requirements for continuously lit pilot flames and control room alert systems to NSPS OOOOb and EG OOOOc. The owner or operator must also verify the flare is lit at least once every five minutes. These requirements should help to resolve instances of unlit flares.

Comment: Commenter (2383-BH) recommends that EPA distinguish between pressure-assisted flares and flares “other than pressure-assisted flares” (i.e., unassisted flares) in the flare monitoring requirements. For pressure-assisted flare, the commenter recommends that EPA set the degree of emissions limitation achievable at 98 percent. The commenter states there are commercially available technologies, such as their flare.IQ technology solution, that allow operators to achieve a combustion efficiency of 98 percent. This technology has been installed by operators worldwide. The commenter believes the EPA proposed 95 percent destruction threshold is not justified given the availability of such systems.

Response II-17-55: EPA disagrees with the commenter. The required BSER for various affected facilities in NSPS OOOOb and EG OOOOc is 95 percent control. As such, owners and operators must meet 95 percent control of emissions from affected or designated facilities subject to those standards at all times. The rules do not specify what type of control device must be used to achieve this standard, nor is EPA setting a control efficiency for different types of control devices. All control devices must achieve the minimum required emission reduction standard, although some control devices at individual sites may perform better than the required 95 percent emissions reductions. Additionally, although it may be possible to achieve 98 percent control of emission, EPA determined that 98 percent control efficiency is not cost effective and is therefore not BSER.<sup>36</sup>

#### ***17.2.4 Flare Alternative Methods and Monitoring Recommendations***

Comment: Commenter (2457-Providence Photonics) states that the proposed flare monitoring requirements have some similarity to the ones in the refinery and ethylene MACT (40 CFR 63.671) in the sense that they all require continuous monitoring but recommends that EPA consider adding an alternative approach that will be more cost effective and will achieve the same objective to ensure that the flare has high combustion efficiency.

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<sup>35</sup> 87 FR 74794 (December 6, 2022).

<sup>36</sup> 87 FR 74794 (December 6, 2022).

Commenter (2457-Providence Photonics) points out that there have been significant advancements in the field of flare performance monitoring technology in recent years since the promulgation of the refinery and ethylene MACT, including the Video Imaging Spectral Radiometry (VISR) technology (which has been developed to remotely and directly monitor flare combustion efficiency (CE)) and the Simplified VISR technology (which has been developed to remotely monitor Combustion Zone Net Heating Value (NHVcz) for steam-assisted flares and Net Heating Value Dilution Parameter (NHVdil) for air-assisted flares)<sup>37</sup>. In November 2022, the commenter explains that EPA funded additional testing with focus on the Simplified VISR technology on both steam-assisted and air-assisted flares at the John Zink flare testing facility in Tulsa, Oklahoma. The commenter summarized the test results in Exhibit 3 of their letter and explains that as shown in Exhibit 3, the Simplified VISR technology can be easily deployed for a short-term study or long-term continuous monitoring of NHVcz for steam-assisted flares or NHVdil for air-assisted flares at a cost comparable to an OGI camera.

Commenter (2457-Providence Photonics) suggests that EPA allow operators to use the Simplified VISR method to demonstrate compliance in lieu of a calorimeter or the 10-day testing. If an operator chooses the continuous monitoring route, the commenter suggests the operator could have a choice between a calorimeter and the Simplified VISR. The commenter explains that each operator could choose between these two methods based on the total cost and the circumstances (e.g., scheduling, operational constraints, maintenance, etc.). If an operator chooses 10-day testing, the Simplified VISR device could be installed to monitor the flare for 10 days states the commenter. The commenter believes that the Simplified VISR device can operate autonomously and continuously, a significant advantage over manually operating and collecting at least 200 hourly samples.

To facilitate the above alternative approach, the commenter (2457-Providence Photonics) suggests that the flare NHV standard should be supplemented. While the current NHV standard is based on the Btu/scf in the gas stream that is fed to the flare (e.g., 300 Btu/scf and 800 Btu/scf), the Simplified VISR measures the NHV in the flame combustion zone, which the commenter states represent a better surrogate parameter for flare performance than vent gas NHV. To facilitate the Simplified VISR as an alternative to the methods in the Supplemental Proposal, the commenter recommends that the final rule should allow the operator to comply with the NHVcz and NHVdil based standards (i.e., reference the NHVcz limit of 270 Btu/scf for steam assisted flares and NHVdil limit of 22 Btu/square feet (sqft) for air-assisted flares in 40 CFR 63.670). The commenter states it is important to note that the 270 Btu/scf NHVcz and 22 Btu/sqft NHVdil standards correspond to a combustion efficiency of 96.5 percent and destruction efficiency of 98 percent, which is higher than the control efficiency of 95 percent in the December 2022 Supplemental Proposal and represents a 60 percent methane emission reduction (from 5 percent of the flared process stream down to 2 percent). Adding this stronger standard as an option is beneficial to the environment and from the operators' perspective, it will provide more flexibility for compliance, states the commenter. The commenter believes an operator may consider all aspects (cost, supply, schedule, operational constraints, manpower, maintenance,

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<sup>37</sup> See Providence Photonics' comments on the November 2021 proposal, which can be found at EPA-HQ-OAR-2021-0317- 0604.

etc.) and conclude that the Simplified VISR method is a better choice, even though it means complying with a higher environmental standard.

Furthermore, commenter (2457-Providence Photonics) suggests the EPA should consider some incentive for operators who choose the NHVcz or NHVdil because it further reduces the methane emissions. The commenter recommends that the incentive could be in the form of an emission credit where applicable, i.e., the difference between the 95 percent control and 98 percent control can be used as emission credit and such a credit could be used for offsetting emissions in the air permitting process.

In addition to NHV related monitoring requirements, the commenter explains that if an operator chooses to use the Simplified VISR alternative, it could simultaneously satisfy all the monitoring requirements in 40 CFR 60.5417b(d)(1)(viii)(A) thru (E) –

(A) for monitoring the pilot – Simplified VISR device can be used to detect the presence of pilot flame; (Commenter’s Exhibit 4)

(B) or (C) for monitoring the NHV – See above discussions; (Commenter’s Exhibit 3)

(D) for monitoring flowrate – Simplified VISR device can be used to measure the flaring rate in terms of kilograms (kg)/hour (hr) (or pounds(lbs)/hr) of hydrocarbon being flared; and (Commenter’s Exhibit 5)

(E) for monthly inspection of visible emissions – Simplified VISR continuously monitors visible emission through application of the Smoke Index. (Commenter’s Exhibit 6)

Commenter (2457-Providence Photonics) believes the most efficient approach to adopt the above recommended Simplified VISR Alternative is to incorporate it in the final rule, specifically, 1) adding provisions to allow the Simplified VISR method as an alternative to calorimeter method in 40 CFR 60.5417b(d)(1)(viii)(B) or 10-day sampling method in 40 CFR 60.5417b(d)(1)(viii)(C); and 2) adding the NHVcz and NHVdil based standard as alternative to the vent gas Btu/scf based standard by referencing both 40 CFR 60.18 and 40 CFR 63.670.

Commenter (2457-Providence Photonics) states that a much less efficient approach to adopt the above recommendation is to allow the operator to apply for it, similar to the procedures to apply for an alternative test method in 40 CFR 60.5398b(d) in the December 2022 Supplemental Proposal. However, the commenter believes that the procedures in 40 CFR 60.5398b(d) apply to the fugitive emission standards only, so EPA should add a section that will mimic 40 CFR 60.5398b(d) in principle but will be geared towards the flare standards.

Response II-17-56: See discussion in section XI.H.6 of the preamble to the final rule which details EPA’s final standards related to alternative approaches to combustion device monitoring.



### **17.2.5 Regulatory Language and Clarifications for Flares**

Comment: Commenter (2326-AXPC) requests that EPA clarify its intent with respect to demonstrating initial flare compliance, which requires compliance with 40 CFR 60.18(b). The commenter cites to proposed 40 CFR 60.5412b(a)(3) and 40 CFR 60.5412c(a)(3), in part:

Each flare must be designed and operated according to the requirements of §60.18(b) as specified in paragraphs (a)(3)(i) through (iv) of this section.

(i) You must use Method 18 of appendix A-6 of this part to determine the NHV of the vent gas meets the requirements in §60.18(c)(3)(ii). For pressure-assisted flares, in lieu of the heating value limits in §60.18(c)(3)(ii), the NHV of the gas being combusted must be 800 Btu/scf or greater.

The commenter explains that 40 CFR 60.18(b) identifies that flares must comply with 40 CFR 60.18(c)-(f). 40 CFR 60.18(c)(3) provides operators a choice to adhere to heat content specifications in 40 CFR 60.18(c)(ii) and the maximum tip velocity specifications in (c)(4), or to adhere to the requirements in (c)(3)(i). The commenter believes it is unclear whether EPA intends that operators do not use the compliance option in 40 CFR 60.18(c)(3)(i) and requests that EPA clarify its intent with respect to how operators are to comply with 40 CFR 60.18(c), as referenced by 40 CFR 60.18(b).

Response II-17-57: EPA does not expect flares used in the oil and natural gas sector to be able to meet the hydrogen content requirements in §60.18(c)(1)(i).

Comment: Commenter (2399-GPA) requests clarification regarding flare testing requirements under proposed revisions to 40 CFR 60.18(d). The commenter states that it is not clear if 40 CFR 60.18(d) requires a formal test or some sort of certification that the flare meets applicable requirements, nor is it clear whether all flares must meet a testing or certification requirement. If 40 CFR 60.18(d) requires a formal test, the commenter would like to ensure that adequate time is provided for the necessary installation of ports to perform the flow and heating value requirements per the test methods in 40 CFR 60.18(d) on a live flare line.

Response II-17-58: Flares are exempt from the performance testing requirements of NSPS OOOOb and EG OOOOc. Flares must be able to demonstrate compliance with the requirements for pilot flames, visible emissions, vent gas flow rate, and net heating value outlined in the rule. However, there is no formal performance testing requirement or certification for flares.

Comment: Commenter (2305-Williams) states that EPA's requirement to report all volumetric flowrate exceedances as deviations misunderstands an application of processing plant flares as emergency control devices. According to the commenter, by identifying any measured exceedance of 40 CFR 60.18(b) volumetric requirements as a deviation, EPA fails to accommodate instances in which flares at natural gas processing plants are used as emergency control. In 40 CFR 63.670(o)(3)(i)-(ii), the commenter notes that the EPA acknowledges that

flares in the refinery sector are used for emergency control and develops a regulatory framework to support this application. The commenter requests that the EPA adopt a similar framework for flares (for maximum flare tip velocity) at natural gas processing that temporarily serve this same emergency control function.

Response II-17-59: EPA intentionally did not include all the flare provisions in 40 CFR 63.670 for oil and gas facilities subject to NSPS OOOOb and EG OOOOc. We specifically did not include requirements to develop a flare gas management plan or other “emergency flaring” provisions in 40 CFR 63.670(o), which includes reporting requirements for all such events. Additionally, some events conducted under the emergency flaring provisions in 40 CFR 63.670(o) are automatic violations (as opposed to deviations).

EPA also notes that we did not include these specific provisions related to “emergency flaring” and determining the “smokeless capacity” of the flare in other recent rulemakings where we otherwise incorporated the flare provisions in 40 CFR 63.670, even though these flares may be used as emergency flares.<sup>38</sup> In other recent rulemakings,<sup>39</sup> while we may have incorporated some of the emergency flaring provisions, we did not incorporate the provisions in 40 CFR 63.670(o)(3)(ii) related to exceedance of maximum flare tip velocity; instead all exceedances of the maximum flare tip velocity limits are reportable as deviations, consistent with the requirements we proposed for NSPS OOOOb and EG OOOOc. We find that the direct application of the maximum velocity limits provides a more direct means of requiring facilities to manage their flares without the burden associated with the provisions in 40 CFR 63.670(o). As such, EPA is finalizing the flare tip velocity limits as proposed.

## **17.3 Enclosed Combustion Devices (ECDs) and Other Control Devices**

### ***17.3.1 Monitoring and Testing***

Comment: Commenter (2326-AXPC) requests that EPA provide the same continuous flow monitoring alternatives for all ECDs, regardless of whether they are tested on-site, or tested by the manufacturer. The commenter requests that EPA harmonize the requirements to allow operators of any ECD with an alternative to measure flow directly with a flow meter or “other parameter monitoring systems combined with engineering calculations, where (1) for maximum inlet flow rate, the operator can demonstrate the maximum flow rate to the ECD cannot cause exceedance of the ECD’s maximum inlet flow rate, or (2) for minimum inlet flow rate, the operator installs and operates a “backpressure preventer which is set to operate at or above the minimum inlet gas flow rate.”

Commenter (2326-AXPC) notes that the monitoring of an ECD’s inlet flow is physically indistinguishable among devices performance tested by a manufacturer or the operator because the performance test does not impact inlet flow rate characteristics. Rather, as the December

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<sup>38</sup> See, for example, Organic Liquids Distribution NESHAP at 40 CFR 63.2380(e).

<sup>39</sup> See, for example, Miscellaneous Organic Chemical Manufacturing NESHAP at 40 CFR 63.2450(e)(5)(v) and Ethylene Production NESHAP at 40 CFR 63.1103(e)(4)(iv). Also see proposal regulatory text for Synthetic Organic Chemical Manufacturing Industry: Organic NESHAP, 40 CFR part 63, subpart F; available in docket EPA-HQ-OAR-2022-0730.

2022 supplemental proposal requires, the commenter explains that the performance test establishes, among other things, a minimum and maximum flow rate within which the device will meet requisite emissions reduction requirements. The commenter adds that this range has no bearing on whether the operator can demonstrate the maximum flow to the ECD will remain below the maximum flow rate established in a performance test, and a “backpressure preventer” will perform the same across all ECDs to ensure flowrate to an ECD remains above the minimum flow rate established in a performance test.

Response II-17-60: See response II-17-16, which responds to this issue.

Comment: Commenter (2399-GPA) suggests that temperature during control device testing is the best indicator of combustion performance and should be an available alternative to continuous monitoring. The commenter states that temperature monitoring should not be based on just a static number but on the temperature achieved during the initial performance testing that demonstrates required destruction efficiency set as a minimum temperature limit. The commenter suggests that the minimum temperature could be updated in subsequent performance tests if the required destruction efficiency can be met at a lower temperature. The commenter is concerned that the temperature limit in proposed 40 CFR 60.5414b(c) is unnecessarily high and would require a large amount of supplemental fuel gas to maintain continuous compliance with the limit generating additional greenhouse gas emissions from the combustion of supplemental fuel. Further, the commenter notes, the proposed limit appears to be based on a temperature in the flame zone which many enclosed combustors cannot monitor. The commenter explains that most enclosed combustors have thermocouples installed above the flame zone in the combustion chamber, resulting in lower read temperatures due to the location. If the thermocouple is used during testing, however, the commenter states that the test should demonstrate that proper combustion is occurring. Therefore, the commenter requests that EPA provide more flexibility in temperature testing to account for the differences inherent in enclosed combustor design.

Response II-17-61: See response II-17-70, which responds to this issue.

Comment: Commenter (2294-OOGA) believes that the proposed control device testing and monitoring requirements are unworkable. The commenter explains that oil and natural gas production facilities typically use ECDs to control VOC and methane emissions that result from the collection of well liquids during production activity. During natural gas production, well liquids are brought to the surface periodically and are routed to a storage tank and this activity occurs intermittently and often unpredictably. For many well facilities, the commenter states the resulting off gassing of the collected liquids, also known as “flash gas”, directs these emissions to an ECD resulting in low flow rates near ambient pressure. The commenter explains that the inherent nature of this operating scenario leads to several technical issues related to the proposed test methods for conducting performance testing on these ECDs. Specifically, the commenter is concerned that many of the test methods required under the supplemental proposal may be incapable of yielding reasonably representative data under conditions as described above. Additionally, the commenter is concerned that the short duration of certain of these venting events may be less than the response time of a test method. By way of example, the commenter states that inlet flow measurement on ECDs with intermittent operation can be problematic due to short duration and low flow velocity. EPA Methods 2, 2A, 2C, and 2D, which are proposed

for flow measurement, are likely to result in inaccuracy due to the random and unpredictable nature of the venting process, states the commenter and this uncertainty in effectively employing any of these methods will result in inaccurate measurement. As an alternative, the commenter recommends that Method 2B could potentially be employed in these low flow, intermittent flow situations to provide more representative data.

Commenter (2294-OOGA) states that EPA Method 4 also has limitations as the intermittent nature of the normal operation of these ECDs would interfere with the ability to obtain the required minimum sample volume. Additionally, the commenter explains that the ability to capture a representative sample of the actual moisture content of the flash gas is limited due to the inherent non-instantaneous response time for activating the sampling train simultaneously with a venting event, states the commenter. Finally, the commenter is concerned that EPA Method 18 may have similar limitations as Method 4 as the test equipment response time may not allow for a representative sample to be obtained, given the nature of the described process.

The commenter (2294-OOGA) notes that EPA has faced similar control device testing challenges in the past, and describes, for compliance testing purposes, the National Emission Standard for Hazardous Air Pollutants Subpart HH allows an “end of stack” method to demonstrate compliance. The commenter urges EPA to consider and allow alternative test methods that would be better suited for low pressure, low flow, intermittent emission sources similar to the example described above.

The commenter (2294-OOGA) also is concerned with the proposed monthly Method 22 opacity observations of ECDs, because as with performance testing concerns noted above, production facilities that have intermittent and unplanned operation of ECDs will be challenged by this requirement. The commenter asks EPA to clarify that Method 22 opacity observations for these intermittent sources be conducted on an “as found” basis. The commenter explains that well facilities are often widely distributed over large areas, explains the commenter and even if an operator is in the general vicinity of an ECD, given the intermittent and unplanned operation of the process, the operator may not be able to receive an indication that the ECD is in operation, travel to the ECD location, and conduct a Method 22 observation before the unit discontinues operation. Furthermore, they add that many well production facilities are unmanned, thus making the ability to be present during operation of this type of ECD process for conducting Method 22 impracticable, states the commenter.

Response II-17-62: EPA is not adding the option for EPA Method 2B into the final rule, as it is more accurate to measure flow directly for the control efficiency testing required in NSPS OOOOb and EG OOOOc. This is consistent with the requirements in other sectors, as well as NSPS OOOO and NSPS OOOOa.

EPA notes that in NSPS OOOOb, EPA Method 18 is not an acceptable test method. Because both VOC and methane must be controlled, EPA proposed, and is finalizing, EPA Method 25A as the test method for demonstrating compliance with the control device requirements. For EG OOOOc, EPA Method 18 is an acceptable test method since methane is the only regulated pollutant. However, EPA has provided owners and operators the option to use EPA Method 25A or EPA Method 320 to demonstrate compliance in lieu of EPA Method 18. Additionally, as

noted in section XI.H.1 of the preamble to the final rule, EPA is finalizing an outlet concentration that can be used to demonstrate compliance in lieu of inlet and outlet testing. When determining compliance with the outlet concentration limit, measurement of flow by EPA Method 2 and measurement of moisture by EPA Method 4 are not required. This change should help to alleviate many of the issues raised by the commenter.

Owners and operators who cannot use any of the options outlined in the rules may also seek an alternative test method in accordance with §60.8(b). Additionally, §60.8(b) allows the delegated authority to approve shorter sampling times when necessitated by process variables.

Additionally, see response II-17-8, which addresses the issue of visible emissions observations on non-operational units.

Comment: Commenter (2326-AXPC) explains that recent experience in Colorado demonstrates that performance testing ECDs is infeasible without the use of supplemental gas for ECDs that control intermittent vapor streams – *e.g.*, storage vessel vapor streams. Where flow is intermittent, the commenter explains, obtaining a single one-hour run, much less three, is infeasible without use of supplemental gas. The commenter is also concerned that installation of a backpressure preventer to ensure inlet flow to the ECD is above the device's minimum flow rate will only exacerbate this issue, as a backpressure preventer ensures intermittent emissions flow to the ECD. Accordingly, the commenter requests that EPA either exempt ECDs from performance testing where normal inlet flow to the ECD is insufficient to facilitate a performance test or clarify that operators may use supplemental gas to facilitate the performance test.

Response II-17-63: §60.8(b) allows the delegated authority to approve shorter sampling times when necessitated by process variables. Additionally, §60.8(c) requires performance tests to be conducted under the conditions specified by the delegated authority, based on representative performance of the affected facility. Owners or operators should work with their delegated authorities to determine whether the addition of supplemental gas constitutes representative performance of the affected facility.

Comment: Commenter (2399-GPA) is concerned that the flowrate monitoring requirements in the supplemental proposal present significant technical difficulties and, in some cases, may not be possible. The commenter explains that many of these systems operate at, or slightly higher than, atmospheric pressure, meaning that only small volumes of gas will be sporadically released. They add that these systems are not designed to provide three hours of continuous flow to the control device. The commenter understands that manufacturer tested emission control devices provide an inlet pressure requirement, which thereby mandates installation of a control valve and pressure monitoring. According to the commenter, this, as well as improved liquids handling, leads to intermittent vapor routing making traditional performance testing, which consists of three one-hour runs, very difficult to complete. By way of example, they provide that a member company compiled one month's worth of data on pressure actuating at a tank facility and the valve (routing vapors to enclosed combustion device) opened for an average of eight seconds per actuation. The total time that vapors were routed to the control device during a day was under seven minutes.

Commenter (2399-GPA) requests that EPA allow for the use of pressure monitors coupled with control valves in lieu of flow rate monitoring because pressure monitoring achieves the same goal- ensuring that a sufficient volume of waste gas is going to the control device to ensure proper combustion. The commenter notes that many of the tank facilities that would be covered by the control requirements are already controlled by pressure monitors and control valves that route vapors to the control device only when tank pressure meets the manufacturer's set point for complete combustion and the safety setpoints on the tank pressure relief devices. The commenter provides as an example that, if a tank is rated to hold a pressure of 16 ounces, then a pressure transducer will open and allow vapors to the control device when the pressure reaches 10 ounces and it will close when pressure drops to seven ounces. The commenter states that certain manufactures report that only one ounce of pressure is needed to achieve good combustion, making pressure monitoring an accurate and reliable alternative to flow rate monitors.

Response II-17-64: §60.8(b) allows the delegated authority to approve shorter sampling times when necessitated by process variables. Owners and operators should work with their delegated authority on a site-specific basis to determine what constitutes representative testing for the control device.

EPA notes that NSPS OOOOb and EG OOOOc allow for pressure monitors in lieu of flow monitors.

Comment: Commenter (2428-API) asserts that EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance. In the preamble, the commenter points to an EPA statement that previously tested manufacturer control devices “would not need to perform new performance tests” and “[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA’s website”. The commenter argues that this minimum flow rate information must be added to the EPA’s website<sup>40</sup> no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. The commenter adds that this minimum flow rate information may also not be easily obtained from the manufacturer directly and EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. The commenter suggests that if the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period.

Response II-17-65: EPA will be updating the list for combustion control devices tested by the manufacturer located on our website to include the minimum inlet flow rate for combustion devices that have demonstrated the performance requirements.

Comment: Commenter (2288-NDDEQ) states that for control devices used to comply with emissions standards, the supplemental proposal requires a full Method 25A test for the control

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<sup>40</sup> <https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers>.

device to determine the 95 percent methane reduction requirement in 40 CFR 60.5412c(a)(1)(i). The commenter notes that they have previously commented that, due to issues with sales line access that control devices are required by state law at sites even if a sales line is available, in situations where access is cutoff or otherwise reduce due to pipeline maintenance/emergencies, pressure limitations, or lack of takeaway capacity within the pipeline itself. Specifically, they provide that North Dakota state law requires that organic compounds gases and vapors be burned by a flare or an equally effective control device (except when from an emergency vapor blowdown system or emergency relief system). The commenter explains that this essentially requires every well site that could emit "organic compounds gases and vapors" (North Dakota Administrative Code Chapter 33.1-15-07-02) to have a flare of some type. The commenter is concerned that the testing requirements would put an undue burden on operators utilizing what is essentially a backup device to safely dispose of the gas and prevent venting during such upsets and other temporary disruptions. The commenter requests that control devices used temporarily when associated gas cannot be sold or otherwise routed for beneficial use be exempted from the operational and performance testing requirements.

Commenter (2288-NDDEQ) is also concerned with the sheer volume of performance testing reports that will be generated to demonstrate continuous compliance, and as per the proposed model rule language in EG OOOOc, that the reports be submitted solely to EPA through CEDRI. If it is EPA's stated intention for EG OOOOc to largely supplant older NSPS "because the presumptive standards proposed for EG OOOOc result in the same or greater emission reductions than the current standards in the older NSPS" (87 Fed. Reg. 74,716), the commenter states that these reports will strain the commenter's ability to properly review them if it causes every single existing well facility to be affected.

The commenter (2288-NDDEQ) reports that every well site that has the potential to emit "organic compounds gases and vapors" is currently required to have a flare or equally effective control device per state law, the commenter estimates roughly 7,000 flares being used to safely dispose of the high pressure "associated gas" from the wellhead in addition to a similar number of flares being used to safely dispose of the low-pressure gas from onsite storage vessels. The commenter is concerned that the proposed EG OOOOc does provide a performance test exemption for flares designed and operated in accordance with 40 CFR 60.18(b), however it is unknown how many such flares in North Dakota qualify. In a worst-case scenario, the commenter notes that North Dakota could have 14,000 flares subject to periodic testing. When added to the required 60-month testing period deadline as described in 40 CFR 60.5407c(b)(a)(ii), this results in thousands of additional tests that will be required every year throughout North Dakota. The commenter states that these are tests that they (as a state agency) will be obligated to review to ascertain operator compliance with the EG OOOOc.

Response II-17-66: EPA has determined that 95 percent control of emissions from affected or designated facilities is BSER. Any control device used to achieve this standard must meet the monitoring and testing requirements in the rule. However, §60.8(b) allows the delegated authority to waive performance tests if the owner or operator can demonstrate by other means, to the satisfaction of the Administrator, that the affected source is in compliance with the standard. Additionally, devices that are onsite but not in use are exempt from testing requirements until

they are started up. EPA notes that flares are exempt from performance testing requirement, but they must meet the monitoring requirements specified in NSPS OOOOb and EG OOOOc.

EPA acknowledges the concern of the commenter regarding the volume of performance test reports. EPA notes that its electronic reporting program is intended to ease the burden on delegated agencies. Standardizing the reporting format requires the reporting of specific data elements, thereby helping to ensure completeness of the data and allowing for accurate assessment of data quality. Imbedded quality assurance checks perform some of the required method calculations, reducing errors in test reports. The report standardization and imbedded quality assurance check assist in quicker and more accurate determinations of compliance.

### ***17.3.2 Regulatory Language and Clarifications for Other Control Devices***

Comment: Commenter (2288-NDDEQ) notes that NSPS OOOOa and the proposed NSPS OOOOb language list performance testing procedures for control devices under 40 CFR 60.5413 (a or b depending on subpart), however, there is no 40 CFR 60.5413c. Instead, the performance testing procedures for control devices in EG OOOOc are listed under 40 CFR 60.5407c. The commenter recommends that 40 CFR 60.5407c be moved to 40 CFR 60.5413c for consistency with the other subparts. Additionally, they point out that despite section 40 CFR 60.5413c not formally existing in the proposed language, references to 40 CFR 60.5413c occurs twice in the model rule, presumably as holdovers from an earlier draft of the rule language:

1. At 40 CFR 60.5398c(b)(a)(iv): "If the results of the periodic screening in paragraph (b)(4)(i) of this section indicate a confirmed detection at a designated facility, and the ground-based monitoring survey and inspections required by paragraph (b)(4)(ii) of this section demonstrate the confirmed detection was caused by a failure of a control device subject to 60.5413c", "60.5473c" presumably should be replaced with "60.5407c".
2. At 40 CFR 60.5412c(a)(1)(vi): "You must operate each enclosed combustion control device at or below the maximum inlet gas flow rate established in accordance with 60.5417c(f) and as determined in your performance test conducted in accordance with 60.5413c(b)". "60.5413c(b)" presumably should be replaced with "60.5407c(b)".

Response II-17-67: EPA agrees with the recommendation made by the commenter. The testing requirements in EG OOOOc have been moved to §60.5413c.

Comment: Commenter (2428-API) believes that manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing. The commenter explains that under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing, and under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. The commenter notes, however, that NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. The commenter is concerned because they believe that these requirements appear contrary to both the technical challenges in conducting performance tests in



the field reiterated by EPA and the agency's intent stated in the August 2011 preamble for the proposal of NSPS OOOO:

[w]e believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations.

[Text omitted for brevity.]

For these reasons, we believe the manufacturers' test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance.<sup>41</sup>

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, commenter (2428-API) recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

Response II-17-68: EPA disagrees with the commenter. Manufacturer-tested control devices continue to be exempt from initial testing by the owner or operator but must be tested periodically. However, degradation occurs as control devices age, and it is important that these combustion devices perform periodic testing to demonstrate that they are still capable of achieving the required control efficiency.

Comment: Commenter (2399-GPA) requests confirmation that control devices do not need to be continuously tested when they have a manufacturer's certification. The commenter believes that EPA intended to exempt manufacturer-certified enclosed combustors from continuous testing, however, the commenter believes the regulatory text itself could be written to state that intent more directly. Accordingly, the commenter asks that EPA clarify and confirm that manufacturer-certified control devices would only be required to meet the minimum and maximum flow requirements from the manufacturer to be compliant with NSPS OOOOb and EG OOOOc.

Response II-17-69: EPA disagrees with the commenter. Manufacturer-tested control devices are exempt from initial testing by the owner or operator but must be tested periodically. The EPA recognizes that there was inconsistency in the regulatory text at proposal regarding the testing requirements, and we have revised §60.5413b and §60.5413c to reflect this requirement more accurately.

Comment: Commenter (2428-API) recommends that the minimum operating temperature and associated monitoring requirements be revised. The commenter notes that NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing while other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to NHV monitoring requirements. The commenter states that given the increased number of

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<sup>41</sup> 76 FR 52785 (August 23, 2011).

control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- Allow operators the flexibility to comply with either temperature or NHV requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with NHV requirements as an alternative.
- Allow the minimum operating temperature to be established by performance testing. Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95 percent control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.
- Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices. As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Response II-17-70: EPA agrees that owners and operators should have the flexibility to comply with either temperature monitoring or the net heating value and flow monitoring requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance. However, we don't think that any changes to the regulatory text are needed to support this flexibility. Owners and operators can choose not to demonstrate the correlation during the performance test or choose not to establish a minimum temperature limit in the performance test report. If an owner or operator choose not to demonstrate the correlation or establish a minimum temperature limit in the performance test report, the enclosed combustion device would be subject to requirements for enclosed combustion devices that do not demonstrate that combustion zone temperature is an indicator of combustion efficiency. An owner or operator could also inform the delegated air agency that it is choosing to comply with the requirements for enclosed combustion devices that do not demonstrate that combustion zone temperature is an indicator of combustion efficiency instead of with the temperature monitoring provisions.

EPA agrees that it is appropriate to allow owners and operators to establish a minimum operating temperature during the performance test, similar to how other operating parameters are established. We have updated the requirements of NSPS OOOOb and EG OOOOc in the final rule to incorporate this change.

EPA disagrees that we should allow the option for a minimum operating temperature and temperature monitoring for manufacturer-tested devices. This has not historically been an option in the manufacturer testing program for the oil and natural gas sector. Allowing it in the final rule for NSPS OOOOb and EG OOOOc would be problematic for several reasons. Firstly, it would create differences in the manufacturer testing program in NSPS OOOOb and EG OOOOc from the program in NSPS OOOO, NSPS OOOOa, NESHAP HH, and NESHAP HHH. Secondly, it could potentially create a disadvantage to those manufacturers who have already conducted testing without having this option. And finally, this option would require extensive changes to how the manufacturer testing needs to be performed. Due to the impacts adding this option would create, if EPA did decide such a change was appropriate, it would be prudent to give stakeholders a chance to comment on a proposal of the changes. As such, we are not providing this option in the final rule for NSPS OOOOb and EG OOOOc.

Comment: Commenter (2428-API) believes that enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing. The commenter explains that under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. The commenter points out that NSPS OOOO requirements changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level and then NSPS OOOOa added a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Commenter (2428-API) explains that NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring, summarizes the commenter. The commenter suggests that given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, enclosed combustion devices for which temperature is correlated with destruction efficiency should be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, commenter (2428-API) offers the following suggested changes to 40 CFR 60.5413b(b)(4)(ii) (underlined text indicates new text and struck out text indicates deleted text):

You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this

section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).

(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this

(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

Response II-17-71: EPA disagrees with the comment. Demonstrating that there is a correlation between temperature and destruction efficiency will relieve owners and operators from certain monitoring requirements, such as inlet net heating value and gas flow rate. However, degradation occurs as control devices age, and it is important that these combustion devices perform periodic testing to demonstrate that they are still capable of achieving the required control efficiency.

Comment: Commenters (2399-GPA, 2428-API) ask for clarifications on requirements for regenerative carbon adsorption systems that use a regenerant other than steam. The commenter asks EPA to confirm that carbon regeneration systems are not subject to control device requirements. The commenters explain that some carbon absorption systems used in the midstream industry do not have access to a steam system, as frequently found at a chemical plant or refinery. In the gas production and processing industry, natural gas and heat exchange systems are used to regenerate the carbon beds instead of steam. The commenters report that these systems can be used when there is the potential for air to enter the system, and a carbon bed does not have a direct fire source, limiting the potential for a fire in the system. The commenters add that the regeneration cycle is infrequent for these systems. The commenters request confirmation that the gas from these regeneration cycles would not be subject to any control requirements in the final rule.

Commenter (2428-API) notes that while the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards. The commenter states that operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. The commenter warns that forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

Response II-17-72: EPA disagrees that the gas from a regeneration system is not subject to control requirements. In the system described by the commenters, the emissions from the production equipment are adsorbed on a carbon bed. The carbon bed is then cleaned (regenerated) by blowing hot air across the carbon bed. If this hot air stream is released directly to the atmosphere, it is releasing all of the emissions that were captured by the carbon bed

initially, which equates to having no control on the production equipment. Therefore, the emissions from the regeneration process must be controlled in some way.

EPA does not intend to force owners and operators to change the operation of their control devices. EPA does not have enough information on the operation of these types of regenerative systems and how best the emissions from the regeneration process can be controlled. As allowed by §60.13(i) and §60.5417(d), owners and operators may request approval from the Administrator for alternative monitoring parameters to those specified in NSPS OOOOb and EG OOOOc; during this process information on the system, the monitored parameters, and how the parameters effectively demonstrate control of emissions should be included in the application. Additionally, owners and operators can choose to continuously monitor the concentration at the outlet of a control device in lieu of monitoring parameters.

Comment: Commenter (2399-GPA) requests that EPA confirm the scope of the use of Vapor Recovery Units as a control device, i.e., where the closed vent system ends, and the fuel gas system begins. The commenter believes that the closed vent system should be included up to the compressor unit as the fuel gas system can have a variety of different break points after it leaves the compressor and may not have another break point up to a heater or compressor. Once compressed, the commenter states that the gas is at a higher pressure and should be considered recovered after it enters the recycle or fuel system.

Response II-17-73: The line routing the emissions from the affected facility to the vapor recovery unit is considered a closed vent system. The lines routing the recovered material to the fuel gas system or sales line are not considered part of an affected facility closed vent system. However, these lines would be covered by the fugitive emissions requirements in NSPS OOOOb and EG OOOOc.

Comment: Commenter (2399-GPA) requests that EPA clarify the meaning of ensuring “that each enclosed combustion control device is maintained in a leak free condition.” The commenter recognizes that the “leak free condition” requirement is not an entirely new concept, but owners and operators need additional clarity to ensure that inspections are completed properly to achieve compliance. The commenter contends that this should be limited to checking for fugitive emissions on the line leading up to the enclosed combustion device, similar to the requirements on a closed vent system. However, the commenter urges that, if EPA intends to require other measures to demonstrate compliance with the “leak free condition” requirement, it should specify those and make those specifications available for review and public comment.

Response II-17-74: EPA notes that the line leading up to the enclosed combustion device is part of the closed vent system and should be inspected as such. Maintaining the combustion device in a leak free condition means maintaining the combustion device so that all emissions sent to the combustion device are controlled by the combustion device. This includes maintaining the combustion device so that there are no visible emissions emanating from a location other than the stack, having no visible holes in the shell of the combustion device, and ensuring seals are in good condition.

### ***17.3.3 Costs and Benefits - Monitoring***

Comment: Commenter (2399-GPA) supports better monitoring for control device equipment but urges that any additional monitoring be cost effective. The commenter believes that as written, the supplemental proposal would require the installation of thousands of flow meters, NHV monitoring devices, and testing ports for compliance purposes. The commenter also requests that a proper cost-effective analysis be performed when considering control device requirements, as the commenter believes the monitoring equipment would cost the industry millions of dollars with costs expected to increase as short-term demand for this equipment dramatically increases (e.g., because of the supplemental proposal, and other rules, requiring similar monitoring equipment). The commenter urges EPA to consider these costs fully before adopting any final rule.

Commenter (2399-GPA) notes that installation of this equipment on existing flares will require a hot tap, which is specialized work that usually requires a third-party contractor to perform. Because of the safety protocols that are required to perform this work, and the nature of the work, the commenter states that it is often a costly install. The cost of performing a hot tap will sometimes be as much as all the other costs to install the equipment, depending on the location of the hot tap, explains the commenter, and they believe these costs should be considered to assess the full costs of controls.

Response II-17-75: EPA maintains that our cost analysis is reasonable. We did not make significant revisions to the requirements for thermal control systems that use temperature as the continuous operating limit, so we assume these comments are related primarily to the flare provisions and the enclosed combustion devices that use the same type of monitoring provisions as flares.

EPA included provisions for these combustion control systems to conduct an initial sampling demonstration rather than requiring installation of a continuous net heating value monitor. We also included provisions that allow owners and operators to use a backpressure regulator valve and engineering calculations to be used, where applicable, to demonstrate compliance with the flare tip velocity or maximum vent gas flow rate standards rather than requiring a continuous flow monitor. We expect that most facilities can use these alternatives and the commenter provided no justification as to why these alternatives would not significantly reduce the number of continuous monitors needed.

Moreover, we considered the cost of adding a control device to meet the emission limitations for various affected facilities in this rulemaking. For existing sources, we provide up to three years from the deadline for state plan submittals (which is 24 months after publication of EG 0000c) to achieve compliance with the proposed provisions, allowing adequate time for installation of controls and monitoring equipment to be timed with a process unit shutdown or facility turnaround, which should minimize the need to use hot taps. Nonetheless, because our cost estimate includes retrofitting affected facilities with a new control device, our costs should overestimate the costs associated with using an existing control device with an upgraded the monitoring system. As such, it is not necessary to revise our cost analysis in response to this comment.

#### **17.3.4 Costs and Benefits – Best System of Emission Reduction (BSER)**

Comment: Commenter (2362-EIP) states that relying on an analysis regarding the cost-effectiveness of requiring different levels of control at storage vessel facilities, EPA proposes to only require flares and other combustion devices to achieve 95 percent reduction of VOCs and methane, claiming that requiring a 98 percent destruction efficiency is not cost-effective and thus does not represent BSER under CAA section 111(a)(1):

[U]sing this example for storage vessel affected facilities, the EPA added the additional monitoring and operational costs expected to ensure a 98 percent minimum destruction efficiency and found that it would not be cost-effective to require control of storage vessels with the potential for VOC emissions below 12 tpy or methane emissions below 40 tpy. However, at 95 percent reduction, it is considered cost-effective to require control of storage vessels with potential VOC emissions of 6 tpy and methane emissions of 20 tpy. Therefore, requiring 98 percent reduction of methane and VOC results in the control of fewer storage vessels, and thus result in fewer overall emissions reductions.

Commenter (2362-EIP) points out that in the proposed rule, EPA states that it “received comments stating that variability in gas flow, pressure, and quality would present challenges to achieving 98 percent control efficiency, especially at low production wells.” Despite this observation, the commenter is concerned that EPA is proposing to allow sources to avoid the kind of continuous monitoring that would capture this variation, and instead rely on initial sampling of NHV over a ten-day period.

Further, commenter (2362-EIP) is concerned that EPA apparently has concluded that a performance standard requiring 95 percent destruction and removal efficiency (DRE) for flares and vapor control units (VCUs) could be applied to storage tanks with a methane PTE as low as 20 tons per year, whereas it would not be “cost-effective” to require a 98 percent DRE for tanks with a methane PTE below 40 tons per year. Because the lower DRE standard would apply to a broader universe of tanks that included smaller sources, the commenter states that the EPA has concluded that it would achieve greater emission reductions than a 98 percent DRE. The commenter suggests that EPA’s analysis is either indecipherable or relies on cost-effectiveness calculations that are erroneous, misleading, or at odds with EPA’s own proposal. By way of example, the commenter states that on p.7-2 of the TSD EPA explains: “For this analysis, we assumed control devices complying with 95 percent control requirement would only have to do initial demonstrations for the velocity and heating value requirements and that control devices complying with 95 percent control requirement would require flow meters and NHV monitors to demonstrate compliance.” The commenter believes the second half of the sentence was meant to state that “control devices complying with 98 percent control requirement would require flow meters and NHV monitors to demonstrate compliance.” If their interpretation is correct, the commenter states that EPA’s finding that a 95 percent DRE is more cost-effective assumes that the proposed rule’s requirement that flares and VCUs be equipped with flow and NHV monitors to assure proper combustion efficiency will never actually be implemented, which they contend is irrational. The commenter states that they attempted to obtain clarification of this language and EPA’s intent shortly before the public comment period ended but received no definitive answer

from EPA. If wrongly interpreted, the commenter asks that EPA explain the meaning of the cited sentence above.

The commenter (2362-EIP) further notes that while EPA has acknowledged that a single control device can serve multiple affected sources within a facility, the analysis in Chapter 7 of the TSD assumes that only one of those affected sources – tanks or tank batteries – will bear the full cost of a flare or VCU and the associated monitoring equipment associated with those control devices. When determining cost-effectiveness, the commenter urges EPA to apportion the capital and operating costs among all the affected sources within a facility that are served by the same control device.

The commenter (2362-EIP) examines other costs which are analyzed in Chapter 7 of the TSD, including capital and operating costs associated with the actual control device (flare or VCU), along with the various monitoring required to keep pilot lights lit and to ensure 98 percent destruction efficiency. The commenter believes that most of the new or existing sources (including relatively small tank batteries) are already operating flares or VCUs and assume 98 percent DRE or greater when reporting post-combustion emissions. If EPA believes a large number of sources affected by the rule are not equipped with these control devices, it should make that information public, states the commenter. Where flares and VCU's are already installed, (which the commenter believes to be the case for most existing oil and gas sources), the commenter states that EPA's analysis must evaluate the costs and benefits of the additional monitoring required to assure compliance with the DRE standards, without including control devices that were paid for long ago.

Commenter (2362-EIP) believes that requiring 98 percent—not 95 percent—destruction efficiency constitutes the best system of emission reduction under CAA section 111(a)(1). The commenter points out that when EPA first promulgated the general NSPS flare provisions from 40 CFR 60.18 (which EPA proposes to incorporate for NSPS OOOOb and OOOOc), the agency assumed that the general provisions would achieve 98 percent destruction efficiency.<sup>42</sup> The commenter also points out that EPA has recently determined that it is cost-effective to require other source categories, such as petroleum refineries and ethylene oxide facilities, to perform monitoring and meet operational limits for flares to achieve 98 percent destruction efficiencies.<sup>43,44</sup> The commenter believes that requiring a 98 percent instead of 95 percent destruction efficiency would result in much larger reductions of VOCs and methane at the affected flares and other control devices. The commenter points to past rulemakings showing that emissions reductions from requiring 98 percent destruction efficiency from flares and other controls here would be significant. By way of example, the commenter states that by instituting more stringent requirements for flares at petroleum refineries in 2015, EPA estimated that the improved refinery flare standards for hazardous air pollutants (HAPs) would reduce HAPs by 3,900 tons per year and VOCs by 33,000 tons per year<sup>45</sup> and EPA estimated that revising the

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<sup>42</sup> See 50 Fed. Reg. 14,941, 14,943 (April 16, 1985).

<sup>43</sup> See, e.g., 79 Fed. Reg. 36,880, 36,911-12 (June 30, 2014).

<sup>44</sup> See 80 Fed. Reg. 75,178, 75,214-15 (Dec. 1, 2015).

<sup>45</sup> 80 Fed. Reg. at 75,226.



standards for 102 existing flares from the ethylene production source category had the potential to reduce HAP emissions by 1,430 tons per year and VOC emissions by 13,020 tons per year.<sup>46,47</sup>

Commenter (2362-EIP) believes that EPA does not rationally explain why it is cost-effective to require other source categories—but not this one—to achieve 98 percent destruction efficiency from flares and other control devices. Further, the commenter states that EPA has arbitrarily and unlawfully only evaluated the costs for monitoring and operating controls at one portion of the oil and gas sector—tank batteries—and failed to evaluate the costs for other types of covered oil and gas facilities, which could be much lower than those for tank batteries. Thus, the commenter argues, EPA has not evaluated what is BSER for other portions of the oil and gas sector, in violation of CAA section 111(a)(1). The commenter also argues that EPA has not rationally explained why the purported costs for tank batteries would also be applicable for other types of oil and gas facilities. The commenter urges EPA to evaluate the cost-effectiveness for requiring 98 percent destruction efficiencies at all other types of oil and gas facilities, including oil wells and processing plants.

Response II-17-76: EPA acknowledges the monitoring alternatives proposed may not fully account for all the variability in gas flow, pressure, and quality that would present challenges to achieving 98 percent control efficiency. As EPA’s cost analysis determined, the costs associated with continuous monitoring systems to ensure 98 percent control efficiency is met at all times was not cost effective, particularly for smaller control systems. EPA is not obligated to require owners and operators to install monitoring systems to ensure 98 percent control efficiency, as our BSER analysis concluded that BSER is 95 percent control efficiency.

EPA disagrees with the commenter’s suggestion that we should share the costs of controls across all affected facilities at a site. When EPA determines BSER for a specific affected facility, we must consider the emissions for that affected facility and the costs of applying controls to that specific affected facility. While we acknowledge that there may be times where multiple affected facilities may be present at a given site, our costs analysis cannot assume that is the case unless all sites have the same combination of affected facilities. When developing the national impacts for the proposed storage vessel requirements, EPA did assume many storage tanks would be controlled based on existing state and federal regulations, and we did not account for costs associated with controlling those storage vessels. However, in the BSER analysis, EPA must consider the reasonable worst-case scenario, which is a new control device being purchased and installed to control the emissions from the affected facility. This is consistent with the analysis we conducted for affected storage vessels. EPA notes that adding continuous monitoring systems to existing control systems is at least as expensive as including continuous monitoring systems as part of a new control system, so our conclusion regarding the cost and cost effectiveness for meeting a 95 percent control efficiency versus a 98 percent control efficiency is equally applicable to facilities with existing control devices.

While EPA specifically evaluated the cost difference associated with requiring control systems to meet 95 percent control efficiency versus 98 percent for storage vessels, as we stated in the December 2022 Supplemental Proposal, we considered that analysis to be generally applicable to

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<sup>46</sup> See 84 Fed. Reg. 54,278, 54,301 (Oct. 9, 2019).

<sup>47</sup> 85 Fed. Reg. 40,386, 40,414 (July 6, 2020).

other affected facilities under NSPS OOOOb because the size range of control devices evaluated for storage vessels cover the range of controls used for other affected facilities.<sup>48</sup>

The commenter cited cost effectiveness and emissions reductions achieved at petroleum refineries and ethylene production sites, but these are much larger sites than typical oil and gas production sites. Additionally, many oil and gas production sites are remote and unmanned and some do not have access to electricity. It is not unreasonable when considering these smaller sources with different constraints that different conclusions are made regarding the cost effectiveness.

As discussed in the December 2022 Supplemental Proposal,<sup>49</sup> EPA is maintaining that BSER is 95 percent control of emissions for affected facilities in NSPS OOOOb and EG OOOOc.

The commenter is correct that the second half of the sentence quoted from the TSD should have stated that “control devices complying with 98 percent control requirement would require flow meters and NHV monitors to demonstrate compliance.”

### **17.3.5 EPA Method 320**

Comment: Commenter (2399-GPA) requests that EPA allow owners and operators to use Fourier Transform Infrared (FTIR) spectroscopy as an alternative to Method 25a. See Proposed 40 CFR 60.5413b(b)(3). The commenter notes that FTIR testing is commonly used for engines and turbines, and EPA previously approved the method for demonstrating compliance with 40 C.F.R., Part 60, Subparts IIII, JJJJ and KKKK and Part 63 Subpart ZZZZ. The commenter provides that this is a more cost-effective testing method than Method 25a, because it can measure multiple pollutants at once with the same monitor, reducing mobilization costs. Accordingly, the commenter recommends that EPA authorize FTIR testing as an option for owners and operators.

Response II-17-77: EPA disagrees that EPA Method 320 (which measures pollutants by FTIR) is more cost effective than EPA Method 25A for NSPS OOOOb. The regulated pollutants for NSPS OOOOb are VOC and methane. EPA Method 25A uses a flame ionization analyzer to report total organic compound concentration based on the calibration gas (propane in NSPS OOOOb). The total organic compound concentration includes the concentration of both VOC and methane; as such, no other methods are required to be conducted simultaneously to monitor additional pollutants.

EPA disagrees that Method 320 is an acceptable measurement method for VOC in this sector due to the variability of the streams sent to the control device. EPA Method 320 is appropriate for measuring specific organic compounds and excels in speciated VOC measurements. However, EPA Method 320 is not a robust total VOC measurement method for determination of compliance with a total VOC emissions limit. Measurement of total VOC by FTIR is particularly problematic after combustion devices owing to the myriad of compounds that can form in the combustion process. Due to the lack of a consistent, demonstrable, and validated approach to

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<sup>48</sup> 87 FR 74794 (December 6, 2022).

<sup>49</sup> 87 FR 74794 (December 6, 2022).

measuring total VOC emissions, primarily due to the lack of a discrete list of compounds constituting the total VOC emissions from combustion, EPA proposed to remove the use of EPA Method 320 from NSPS JJJJ, but ultimately deferred action on that removal to consider the matter on a rule-specific basis.<sup>50</sup>

For EG OOOOc, because the regulated pollutant is methane instead of VOC, EPA has added Method 18 and Method 320 as acceptable test methods when conducting testing to determine control efficiency.

### ***17.3.6 Adequate Time for Implementation-Control Device and Associated Monitoring Equipment Supply Chain Issues***

Comment: Commenter (2428-API) suggests that adequate implementation time must be provided for NSPS OOOOb and EG OOOOc. The commenter states that NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented and member companies already are experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. By way of example, the commenter states that control devices are currently experiencing delays of 3 to 4 months, flow monitors are on backorder for a minimum of 6 to 8 months from suppliers, instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to 24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand, explains the commenter. The commenter requests EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, the commenter requests that EPA provide additional time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb, if it maintains the current applicability date of November 15, 2021.

Commenter (2428-API) states that due to EPA's proposed designation of the applicability date aligned to the November 2021 proposal, operators may not have the adequate flow and NHV monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. The commenter explains that because EPA's proposal for consistent control device monitoring requirements (regardless of the affected facility) between both NSPS OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly and the current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years, states the commenter.

Commenter (2428-API) states that in addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will

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<sup>50</sup> See proposed rule 80 FR 54146 (September 8, 2015). For additional information, see technical memorandum to the docket, Steffan Johnson, September 28, 2015, document ID EPA-HQ-OAR-2014-0292-0008.

require a hot tap on the control device piping or a site shutdown. The commenter explains that a hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. The commenter states that hot taps require high flow rates to facilitate heat transfer during welding, and additional purge gas may be needed depending on the site gas production. The commenter further explains that this procedure presents a higher safety, fire, and explosion risk and due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap. As an alternative to a hot tap, the commenter states that a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. The commenter reports that shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities, explains the commenter. The commenter asserts that a shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

Commenter (2428-API) states that in the 2012 NSPS rule, EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. The commenter adds that other state rules, such as those in Colorado and New Mexico<sup>51</sup>, have allowed for an orderly phase-in period for certain requirements. The commenter urges EPA to consider a similar compliance schedule in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities.

Based on feedback from members, commenter (2428-API) requests the initial compliance period for control device flow and NHV monitoring requirements be extended from 60 days after final publication in the *Federal Register* to at least 1 year after publication in the *Federal Register* to allow operators time to order and install the necessary meters (assuming that the applicability is based on the December 6, 2022, and other comments concerning reconstruction and modification are addressed). Additional time, at least another year, would be required if the rules are finalized as proposed, states the commenter. Specifically, the commenter requests that compliance with the flow and NHV monitoring requirements at 40 CFR 60.5417b(d)(1)(vii)(A), 40 CFR 60.5417b(d)(1)(viii)(B), and 40 CFR 60.5417b(d)(1)(viii)(D) along with related operational requirements be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

Commenter (2399-GPA) is concerned that EPA has not provided enough lead time for installing the monitoring equipment required by the supplemental proposal. The commenter notes the process is complicated by potential supply chain issues that would be expected to arise as the entire industry orders thousands of new monitoring devices that would need to be installed over the next few years. This type of monitoring equipment has already started to see longer lead times because of global supply shortages, explains the commenter. Further, the midstream industry is continuing to grow, which the commenter states means that more and more control devices are being installed every month, requiring the installation of more monitoring equipment.

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<sup>51</sup> 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC.

This does not include the current demand for monitoring equipment from the production sector, cautions the commenter. The commenter reports that plant and compressor stations are currently being built without this monitoring equipment being part of the original plans because there was no reasonable way to anticipate these additional requirements, requiring retrofits almost immediately. As a result, the commenter requests at least one year to install the monitoring equipment for sources subject to NSPS OOOOb.

Commenter (2326-AXPC) is concerned about the new NHV monitoring requirements for combustion control devices, in addition to flow monitoring that the commenter states will cover many more control devices than under current rules. The commenter states that at least for NHV monitoring, this could not have been anticipated, and NHV and flow monitoring equipment and the resources to engineer and install it will be in high demand and short supply. The commenter also has concerns with the proposed enclosed combustion device performance testing requirements, which they note are similar to NSPS OOOO and OOOOa, but will require significantly more testing under NSPS OOOOb and EG OOOOc. The commenter is concerned that the expanded scope of coverage of performance testing requirements will increase demand significantly, and likely well above the current testing resource supply. The commenter suggests it will take at least one year, and likely longer, for performance testing vendors to acquire additional testing equipment and hire and train new personnel to meet the unprecedented demand. The commenter proposes that EPA extend the initial compliance deadline for all combustion control device monitoring and performance testing requirements by at least one year. Alternatively, if EPA is unwilling to provide extended initial compliance deadlines as requested above, the commenter requests that EPA provide extensions where good cause exists, as it did under the recently promulgated Uintah and Ouray Indian Reservation FIP for oil and natural gas sources.<sup>52</sup>

Response II-17-78: See section IX.A of the preamble to the final rule for a discussion on the applicability date for NSPS OOOOb. Additionally, in the final rule, EPA has extended the compliance date for certain affected facilities. See discussion in sections X.F.2, XI.D.4, and XI.E.2 of the preamble to the final rule for a discussion on the compliance date for oil well wells with associated gas, process controllers, and pumps.

EPA has made numerous changes to the final rule to ease the implementation burden and supply chain issues for owners and operators. Many of these changes are discussed in other comments in this chapter. For example, EPA has changed the accuracy requirement for flowmeters on combustion control devices to provide owners and operators with more flexibility on available monitoring devices. EPA has also added more types of sampling systems that can be used to assess net heating value. Additionally, we have included a pathway in the final rule for owners and operators to request alternative approaches for monitoring combustion control devices.

Moreover, EPA included provisions for combustion control systems to conduct an initial sampling demonstration rather than requiring installation of a continuous net heating value monitor. We also included provisions that allow owners and operators to use a backpressure regulator valve and engineering calculations to be used, where applicable, to demonstrate compliance with the flare tip velocity or maximum vent gas flow rate standards rather than

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<sup>52</sup> 40 CFR 40 CFR 49.4169(c).

requiring a continuous flow monitor. We expect that most facilities can use these alternatives, and the commenters provided no justification as to why these alternatives would not significantly reduce the supply chain issues raised in the comments.

EPA also notes that existing sources will have up to three years from the deadline for state plan submittals (which is 24 months after publication of EG OOOOc) to achieve compliance with the proposed provisions, allowing adequate time for installation of controls and monitoring equipment to be timed with a process unit shutdown or facility turnaround, which should minimize the need to use hot taps.

Based on revised compliance deadlines, the fact that control devices for existing designated facilities will not need to be tested immediately, exemptions from performance testing for flares, and the availability of manufacturer tested enclosed combustion devices, EPA does not think that a year extension is needed for performance testing, and the commenter has not provided data showing that these factors were accounted for in the comment. Owners and operators who cannot meet this performance testing deadline should work with their delegated authority. For example, §60.8(b) allows the delegated authority to waive performance tests if the owner or operator can demonstrate by other means, to the satisfaction of the Administrator, that the affected source is in compliance with the standard. Identical control devices with identical operating conditions could be a situation in some circumstances in which the delegated authority is satisfied that both control devices can meet the standard by only testing one control device.

## Chapter 18. Recordkeeping and Reporting

### 18.1 Context for Financial Investments

Comment: Commenters (2190-Miller/Howard Investments, Inc. (MHI), 2191-Boston Trust Walden Company) write from the perspective of international financial investment firms and urge EPA to finalize strong methane emission performance standards that establish a transparent, credible, and empirically based methane emissions reporting framework to improve the accuracy and credibility of reported methane emissions data and enable investors to clearly differentiate between leaders and laggards.

Response II-18-1: The comment is a supportive comment of the December 2022 Supplemental Proposal; as such, no response is required. See also Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.9.1 (Rule-Related Recordkeeping and Reporting Requirements), Response I-23-46, for EPA's response to comments requesting that EPA adopt a reliable reporting framework that investors and other stakeholders can utilize.

### 18.2 Security and Access Concerns

Comment: Commenter (2428-American Petroleum Institute (API)) identifies multiple potential security risks and access issues that could prevent an affected facility from being in compliance with the proposed regulations. The commenter requests EPA implement a secure process, similar to EPA's electronic Greenhouse Gas Reporting Tool (e-GGRT) program to prevent somebody other than an authorized representative from being able to submit information to Compliance and Emissions Data Reporting Interface (CEDRI).

Commenter (2428-API) also points out that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. The commenter reminds EPA that some reporters using the form may have issues using the form if the form is dependent on the macro formatting.

Commenter (2428-API) adds that it is also concerned about the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, the commenter requests EPA evaluate the following language as proposed under new source performance standards (NSPS) OOOOb and emission guidelines (EG) OOOOc, and notes that these concerns also apply to NSPS OOOOa:

- *40 CFR 60.5420b(e)(2):* Commenter believes this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.
- *40 CFR 60.5420b(e)(4):* The requirement for the reporter to notify EPA immediately

- upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.
- *40 CFR 60.5420b(e)(5)(iii)*: It is unclear what EPA is intending for a reporter to include as far as “a description of measure taken to minimize the delay in reporting.” EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.
  - *40 CFR 60.5420b(e)(6)*: System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.

Response II-18-2: The electronic reporting requirements in the final NSPS OOOOb and EG OOOOc are consistent with the electronic reporting requirements across Part 52, Part 60, Part 62, and Part 63. A description of the electronic data submission process is provided in the memorandum “Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,” which is available in the docket<sup>1</sup> for this rulemaking. As stated in that document, the EPA designed this process to be compliant with the Cross-Media Electronic Reporting Rule (CROMERR). The CROMERR (under 40 CFR part 3) provides the legal framework for electronic reporting under all of EPA’s environmental regulations and includes criteria for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document. In order to be CROMERR compliant, CEDRI requires certifiers to go through an identity-proofing process when registering. This ensures that only principals of the company are submitting information for the company.

EPA was unaware of the issue surrounding the macros in the reporting template. The only function of the macro within the workbook is to help the end-user navigate the workbook more easily by hiding tabs within the workbook that are not applicable to the owner or operator. EPA can post a version of the template with the macro removed for those users who are unable to use workbooks with macros. EPA encourages template users to report any issues they experience with templates to [cedri@epa.gov](mailto:cedri@epa.gov) so that these issues can be resolved.

EPA disagrees that owners and operators should have the ability to request an extension for submission of reports if there is any outage in CDX or CEDRI between the end of the reporting period and the date report submittals are due. We understand owners and operators may prepare and submit reports well ahead of the report submittal deadline, and we encourage owners and operators to do so. However, if an outage occurs two weeks prior to the date the report is due, the owner or operator still has two weeks to submit the report. As such, there should be no need for an extension of the reporting deadline. Such relief should only be needed if the outage occurs in the timeframe immediately preceding the report submittal deadline.

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<sup>1</sup> EPA-HQ-OAR-2021-0317-0105.



EPA disagrees that reporting extensions should be granted automatically. EPA notes that there has only been one planned outage of CEDRI in the nearly 12 years that CEDRI has been online. EPA notified users of the outage in advance so that submitters were aware of the expected length of the outage and could plan accordingly. Should a future planned outage be necessary, EPA has the ability to notify CEDRI users in advance about the outage. While CEDRI has had some instances of unplanned outage, these instances are generally short in duration (less than 24 hours). EPA has no reason to expect that longer unplanned outages will occur in the future, as EPA conducts system health assessments and performs upgrades to CEDRI coding to ensure limited outages. EPA informs users of unplanned outages by posting information on the outage in CDX and CEDRI. Additionally, reports are prepared outside of CDX and CEDRI. The only function that occurs within CDX and CEDRI is the report upload and submission. If there is an outage, the upload and submission process is not time intensive and can be completed quickly once CEDRI is back online. For these reasons, EPA does not expect that anyone will need to assert a claim of EPA system outage if owners and operators are making reasonable efforts to report timely. However, EPA has provided an avenue to assert such a claim to cover unforeseen circumstances.

Owners and operators are not required to report CEDRI outages to the delegated air agency unless the owner or operator is asserting a claim of electronic reporting system outage. In the claim, the owner or operator must note the date(s) and time(s) that they accessed the system, and it was down. Additionally, the owner or operator should provide enough information to show that reasonable steps were taken to try and report, and that the reporting delay is due solely to circumstances outside the control of the owner or operator. EPA expects owners and operators to take into account situations that may affect reporting when they have control over these situations. If an owner or operator anticipates problems with their firewall or security system, then the facility should take these types of potential problems into account and plan accordingly. If the facility's computer system has recently undergone software updates, then the facility should consider the possibility that the new software is not compatible with CEDRI and should plan accordingly. Facilities should register for CEDRI as far in advance of the initial compliance date (or any time a certifier changes) as possible in order to ensure that they can complete the identity proofing process prior to the compliance date. Additionally, we recommend facilities start developing reports early, in case any questions arise during the reporting process.

There are several technical support mechanisms available to help preparers and certifiers with CEDRI reporting issues. In addition to HelpDesk, there is a LiveChat option in CEDRI. Both services are available between 8 am and 6 pm Eastern Standard Time, Monday through Friday. Additionally, users can email [cedri@epa.gov](mailto:cedri@epa.gov) with any questions or comments.

Addressing comments regarding the electronic reporting process, which impacts a myriad of regulations and has its own legislative and policy history, is beyond the scope of this rulemaking.

## 18.3 Stakeholder Engagement for Recordkeeping and Reporting

Comment: Commenters (2168-Indiana Oil and Gas Association (INOGA), 2172-Kentucky Oil and Gas Association (KYOGA), 2202-Texas Oil & Gas Association (TXOGA), 2428-API) note that they were not able to fully assess the impacts of EPA's proposed recordkeeping and reporting requirements. Commenter (2428-API) states that there was not enough time, while commenters (2168-INOGA, 2172-KYOGA) state that the availability of only a preamble prohibited them from being able to provide sufficient comments and validate EPA's time and cost estimates related to recordkeeping and reporting. Commenter (2202-TXOGA) states that the proposed regulatory text fails to outline the substantive requirements of CEDRI reporting for NSPS OOOOb and EG OOOOc in any practical detail.

Commenters (2168-INOGA, 2172-KYOGA, 2202-TXOGA, 2326-American Exploration and Production Council (AXPC)) request additional opportunities to collaborate with EPA to develop and revise the recordkeeping and reporting requirements.

Commenters (2168-INOGA, 2172-KYOGA, 2202-TXOGA) request a collaborative process like how industry and EPA worked together after the release of NSPS OOOOa to reduce some of the recordkeeping and reporting burden. Commenters (2168-INOGA, 2172-KYOGA) would like to continue to work collaboratively with EPA to create regulations that are cost-effective and common sense for the operators.

Similarly, commenters (2168-INOGA, 2172-KYOGA) note that when NSPS OOOOa was proposed in 2015, the recordkeeping and reporting requirements were as costly and burdensome as the field work. The regulated community would like to know what recordkeeping and reporting activities will be required prior to the final regulation being released.

Response II-18-3: Regarding the request for additional time to provide comments, please see Volume II, Chapter 23 (Miscellaneous Other Comments), subsection 23.4.1 (Public Comment Period Adequacy (i.e., Request for Extension, Inadequate Time Provided)), Response II-23-20 of this RTC. Contrary to the comment that EPA did not provide sufficient regulatory certainty regarding the recordkeeping and reporting requirements in the proposal, the EPA provided regulatory text and CEDRI templates for NSPS OOOOb and EG OOOOc in the docket<sup>2</sup> to the rulemaking. Further, EPA provided the opportunity to engage with stakeholders through this notice and comment rulemaking, and we have responded to those comments in this RTC document. EPA disagrees that the proposed regulatory text failed to outline the requirements for CEDRI reporting; the CEDRI reporting requirements are included in §§60.5420b and 5420c. The content of the NSPS annual report is included in §§60.5420b(b), 60.5423b, and 60.5424b(a)(1), (b), and (d). The content of the NSPS semiannual report for process unit equipment affected facilities is included in §60.5422b(b) and (c). The content of the annual report in EG OOOOc is included in §§60.5420c(b) and 60.5424c(a)(1), (b), and (d). The content of the NSPS semiannual

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<sup>2</sup> EPA-HQ-OAR-2021-0317-1536.

report for process unit equipment affected facilities is included in §60.5422c(b) and (c).

## 18.4 CEDRI Reporting Template

Comment: Commenters (2168-INOGA, 2172-KYOGA, 2202-TXOGA, 2428-API) identify specific potential issues with the CEDRI proposed template.

Commenters (2168-INOGA, 2172-KYOGA) note that the proposed template is like the template required for NSPS OOOOa reporting. The commenters appreciate that the proposed template has not materially increased the number of pieces of data that need to be reported to EPA. However, the commenters recommend that EPA modify the Initial and Revised tab to not request that the specific number of valves and connectors be counted – but look at a broader metric. They elaborate that if maintenance is performed at a location and a valve or connectors are added or removed, then this could be a source of incorrect data in the future. They also do not believe that the time invested to count every valve and every connector at every wellsite or tank battery every year is a good use of time.

Commenter (2428-API) notes that the control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. The commenter states that this will result in redundant and duplicate information being reported. The commenter also does not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed at §60.5420b(b)(1)(v).

Commenter (2428-TXOGA) also notes that certain selection options for “Deviation Category” the “Description of Deviation” and “Type of Deviation” cells are automatically blacked out and do not allow an operator to provide additional context. The commenter suggests that the operator should have the ability to add free text in these areas and provide additional information as needed.

Response II-18-4: Regarding the comment that the number of valves and connectors should not be specified in the final template, EPA notes that this comment is relevant to the semiannual reporting template for onshore natural gas processing plants and the requirements under 40 CFR §§60.5422b and 60.5422c.<sup>3</sup> The requirement to submit the number of valves and connectors is consistent with the leak detection and repair (LDAR) reporting provisions for onshore natural gas processing plants, going to back to the original promulgation of NSPS KKK for these facilities in 1985. The EPA believed then and continues to believe that understanding the scope of the equipment in the affected facility is necessary to evaluate the remaining compliance reporting elements which must be reported. For instance, knowing the total number of regulated equipment can help EPA identify trends regarding leak rates and repair timelines. Therefore, the

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<sup>3</sup> This template is applicable only for natural gas processing plants and should not be used for fugitive emissions components affected facilities at well sites, compressor stations, or centralized production facilities. Information on fugitive emissions components affected facilities at well sites, compressor stations, or centralized production facilities should be reported using the annual report templates for §§60.5420b and 60.5420c.

EPA is not making the suggested change to the reporting requirements in NSPS OOOOb and EG OOOOc, as reflected in the CEDRI reporting template.

Regarding the comment that the control device and closed vent system tabs on the annual report template are set up where multiple affected facilities that route to a single control device or through the same closed vent must be identified individually on separate rows, EPA notes that the regulatory requirements apply on an affected facility basis, and it is necessary to parse out the compliance status by affected facility. Individually identifying the affected facility allows EPA, the regulated community, and the public, to sort and compile compliance information for the affected facility of interest. Where a common control device or closed vent system is shared amongst affected facilities, users can copy and paste information for subsequent entries, which reduces the burden of re-typing repeating information.

Regarding the comment that certain cells are automatically blacked out based on prior entries in the “Deviations” tab for the annual report template, EPA notes this feature is intended to help end users walk through the form (and subsequently the reporting requirements of the rule). The blacked-out areas indicate that based on the information provided in previous cells, the information in that cell is not required. Additionally, even though the cell is blacked out, the cell is not locked, and the user can still type in the cell – the text will appear white and will be visible in the blacked-out cell. However, to accommodate the commenter’s concern, EPA is including an optional cell for additional information on the deviation tab. Owners and operators also have the option to include additional attachments as part of the zip file submitted to CEDRI; these additional attachments may be used to explain circumstances beyond the information captured by the template or to expound on information reported in the template.

Regarding the comment that reports should not include the information related to well transfers (including name, phone number, email, and mailing address), the commenter did not explain why this information is not necessary or is unduly burdensome. EPA believes this information is necessary to track ownership of wells due to the trend in the sector to sell off well assets frequently.

Comment: Commenters (2202-TXOGA, 2326-AXPC, 2254-Permian Basin Petroleum Association (PBPA)) request EPA publish a draft NSPS OOOOb or combination NSPS OOOOa/b template on its website as soon as practicable, so that the Agency is able to further solicit and accept feedback on the draft template from the regulated community via public events and make needed adjustments so that the final template is ready in conjunction with any forthcoming final rule. Commenter (2254-PBPA) provides that the template is difficult to find and its location within the docket does not facilitate review and comment. The commenter recommends that the draft template be included on the EPA CEDRI site, along with the NSPS OOOOa template. Commenter (2202-TXOGA) suggests that EPA relocate its draft template of the CEDRI reporting and recordkeeping requirements from a footnote in the regulatory preamble and place it in the final rule’s text.

Commenter (2202-TXOGA) adds that if the NSPS OOOOb template review and finalization process will be similar to the 5-year process to finalize the NSPS OOOOa CEDRI template, it will not actually be available for CEDRI reporting for the first NSPS OOOOb annual report.

Commenter (2326-AXPC) elaborates that operators rely on this template to inform recordkeeping and reporting processes, and operators cannot wait until close to the due date of the first annual report to have the final reporting template.

Commenter (2254-PBPA) further states that according to the template itself and the NSPS OOOOb and EG OOOOc rule language, the template is for NSPS OOOOb and EG OOOOc. The commenter believes that the reporting requirements for existing sources should be in coordination with individual states, as will be prescribed in each state's EPA-approved state plan on implementing EG OOOOc. Commenter (2202-TXOGA) states that since EG OOOOc will be implemented by the state under an EPA-approved state plan, it would make better sense to have the regulated community's EG OOOOc reporting flow to the state in which an affected facility is located instead of reporting through CEDRI.

Response II-18-5: The EPA has provided regulatory text and CEDRI templates for NSPS OOOOb and EG OOOOc in the docket<sup>4</sup> to the rulemaking. A docket was established for this rulemaking pursuant to CAA section 307, and also the Administrative Procedure Act (APA) discusses the process by which federal agencies, including EPA, develop and issue regulations. EPA considers the docket to the rulemaking the appropriate placement for draft NSPS OOOOb and EG OOOOc templates, both in terms of providing broad notice of availability to interested parties and in assimilating comments received on the templates. Because the reporting templates reflect the reporting requirements of each specific rule, when a commenter expresses concern about issues related to the template, generally the commenter is also expressing concern about the reporting requirements in the rule. It is important that these comments are captured in the docket, so that they can be addressed during the rulemaking process.

Users may always send information related to issues with templates or requests for revisions on templates to [cedri@epa.gov](mailto:cedri@epa.gov). Major issues with templates, such as issues that cause owners and operators to be unable to submit a report, will be resolved expeditiously. Cosmetic issues or minor issues will be handled on a case-by-case basis. EPA may choose to issue a new minor version of the template, which would allow owners and operators to use either the new or old template, or EPA may make the change at a later date when other changes are necessary.

EPA will post the final reporting templates for NSPS OOOOb and EG OOOOc on the CEDRI website. EPA has chosen not to post the draft forms for this rulemaking on the CEDRI website, due to the confusion that posting the draft NSPS OOOOb reporting template caused owners and operators. In order to limit confusion as to whether the reporting template is available (thus starting the timeframe for when the reporting template is required), EPA now plans to only post final reporting templates on the CEDRI website.

Regarding timing of the final reporting templates, EPA intends to finalize the templates as expeditiously as possible and in advance of the requirement to submit initial compliance reports. In the event this does not occur, EPA notes the final rule provides that the reporting templates are required to be used only once the template has been available on the CEDRI website for at least 90 calendar days.

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<sup>4</sup> EPA-HQ-OAR-2021-0317-1536.

EPA disagrees that the reporting template should be in the final regulatory text. EPA surmises the commenter means the name of the reporting template (which is what was included in the preamble footnote) should be in the final regulatory text. EPA disagrees that it is necessary to include the reporting template name in the regulatory text. Each reporting template is named for the reporting requirement on which the template is based. For example, the NSPS OOOOa annual report template is named `part_60_subpart_60.5420a_annual_report.xslm`. EPA considers it redundant to list this name in the annual report section of §60.5420a. Additionally, on the CEDRI website, reporting templates are listed by subpart, which narrows down the choices and makes the reporting templates easy to find.

Regarding the comment that the reporting requirements for existing sources should be in coordination with individual states, the process of implementing the emissions guidelines in a particular state allows for the state to deviate from the model rule, provided the elements of the submitted plan are at least as protective as the elements in the model rule. See the discussion in sections XIII.C.2.a.iii and XIII.C.4 of the preamble to the final rule.

Regarding the comment that EPA should allow submittal of compliance reports using a state mechanism in lieu of the reporting templates and CEDRI for existing sources under EG OOOOc, EPA acknowledges this as a possibility, although we expect the majority of states to implement the same electronic reporting requirements in their state plans as is required by NSPS OOOOb.<sup>5</sup> As discussed within Section XIII.C.4 of the final rule preamble, states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of standards of performance. See 40 CFR 60.25a. For the reasons that the EPA is requiring electronic reporting for the NSPS, as explained in section X.N of the final rule preamble, EPA included similar provisions within the model rule of EG OOOOc. EPA finds these provisions are preferable to use for state plans and highly encourages states to incorporate the provided reporting templates and CEDRI in their state plans. States must maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements, as described in EG OOOOc. Lastly, EPA notes that 40 CFR 60.5373c(e) specifies that approval of alternatives to electronic reporting cannot be delegated to state, local, or tribal agencies. This means that once EPA has approved a state plan which would already include a reporting structure, the state cannot unilaterally approve an alternative to the EPA-approved electronic reporting. If the state wishes to make a change at that time, they must amend their state plan.

## 18.5 Concerns with Current Regulatory Framework

Comment: Commenter (2270-Private Citizen) notes that the quality of information self-reported by the industry is a big problem.<sup>6</sup> [The article describes enforcement issues with rules to limit methane emissions in New Mexico, including that data reported by operators is inconsistent and

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<sup>5</sup> For example, in response to the November 2021 Proposal, one state noted that most states will not be able to accommodate the amount of paper associated with annual reporting under this rulemaking and state personnel would access reports through CEDRI. See EPA-HQ-OAR-2021-0317-0763.

<sup>6</sup> <https://www.hcn.org/articles/energy-industry-new-mexicos-new-pollution-rules-leave-oil-and-gas-operators-to-police-themselves>.

inaccurate.]

Response II-18-6: The comment regarding perceived issues with the quality of information provided to a state agency are beyond the scope of this rulemaking; as such, no response is required.

## **18.6 Paperwork Reduction Act (PRA)**

Comment: Commenter (2179-Kansas Independent Oil & Gas Association (KIOGA)) believes that EPA has underestimated the annual burden for recordkeeping and reporting requirements in NSPS OOOOa. The commenter estimates their compliance costs to be significantly more than EPA's estimates. The commenter includes estimates based on their understanding of how the regulation will impact their industry. Additionally, the commenter believes that the documentation required by this regulation creates ample opportunities for any operator to be cited by EPA for missing information.

The commenter (2179-KIOGA) states that EPA is estimating that the average owner or operator will spend approximately 38 hours per year (98,438 labor hours/2,554 owners and operators), in the first three years, on compliance reporting activities. This time estimate is expected to cost the average owner \$1,316 per year (\$3,361,074 per year/2,554 owners and operators).

The commenter (2179-KIOGA) estimates a one-time cost to develop a management and reporting system to be \$40,000 - \$50,000 and an ongoing cost of compliance of \$20,000 - \$100,000 per year (one-part time employee early in the program and potentially two full time people within a few years). These estimates are based on their understanding of the final rule, and only to meet the reporting requirements detailed in the regulation and discussed below. These estimates do not include the cost to achieve compliance with their equipment at the affected facilities.

The commenter (2179-KIOGA) also reports that the documentation will necessitate many more hours than the EPA's estimated 38 hours per year. The commenter explains that companies are evaluating the need to hire another one to two people solely to meet the reporting requirements of this new regulation. The commenter believes that a full-time position(s) may be required to meet all the annual reporting and data management requirements to maintain compliance. The commenter estimates that the fully loaded cost (salary and benefits) to fill this position will be an additional \$50,000-\$60,000 per year per person to current operations.

The commenter (2179-KIOGA) adds that the rule also requires owners and operators to develop and maintain a corporate-wide and site-specific monitoring plan. The commenter estimates the effort to develop a robust system will exceed 500 man-hours to solicit input, develop the written program, review with the management team, and implement the program throughout their organization. At a fully loaded cost (salary and benefit) of \$60 per hour, the cost to develop this system is estimated at \$30,000-\$50,000. The commenter views the time invested in developing this type of system as part of the burden for recordkeeping and reporting.

The commenter (2179-KIOGA) notes that EPA requires digital photos and reports to be stored

for up to five years. The commenter reports that the development of a data management system, purchasing of additional data storage systems, and user training will require greater than 600-800 man-hours. At a fully loaded cost (salary and benefit) of \$60 per hour, the cost to develop an information technology (IT) solution is estimated at \$40,000-\$50,000.

Response II-18-7: The recordkeeping and reporting requirements in the rule that apply for each affected/designated facility represent the minimum level of tracking and documentation necessary to ensure compliance with the rule. EPA emphasizes that recordkeeping and reporting are vital components of compliance assurance and believes the recordkeeping and reporting requirements established in the final rule are reasonable and appropriate.

The EPA spent a significant effort in finalizing the specific cost elements used to estimate the recordkeeping and reporting burden when preparing estimates for the 2020 NSPS OOOOa rulemaking in order to address multiple comments received that the EPA had significantly underestimated the time and cost to complete the recordkeeping and reporting requirements (especially associated with the fugitive emissions program) under NSPS OOOOa. The majority of these costs and assumptions were retained in the recordkeeping and reporting burden analyses included in the December 2022 Supplemental Proposal and the final rule estimates, including the assumption of 22 wellsites per company-defined area and for gathering and boosting compressor stations 7 stations per company defined area. See section VII.B (Paperwork Reduction Act (PRA)) of the final rule preamble for EPA's estimate of the recordkeeping and reporting requirements under NSPS OOOOa, NSPS OOOOb, and EG OOOOc.

Comment: Commenter (2428-American Petroleum Institute (API)) believes that it is excessive to require such a significant level of detail to be both documented and submitted for all affected/designated facilities in this proposal. The commenter recommends that EPA simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. The commenter recognizes that it is appropriate to maintain sufficient records to demonstrate compliance, however, suggests that only elements needed for compliance assurance be requested within the annual report. They note that supporting records retained by companies can be made available upon request from the Agency.

Commenter (2179-KIOGA) asserts that the proposed rules include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. The commenter recommends that EPA continue to focus on having operators track the most necessary information to obtain assurance.

The commenter (2179-KIOGA) believes that in the December 2022 Supplemental Proposal:

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.



- EPA continued to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

Response II-18-8: Regarding the general comments that the rule requires excessive or onerous recordkeeping or reporting requirements, or that other mechanisms are in place to ensure compliance, the commenters did not provide suggestions where burden might be reduced.

In the 2020 Technical Rule, the EPA streamlined several of the recordkeeping and reporting requirements in the 2016 NSPS OOOOa and the same simplified requirements were proposed for NSPS OOOOa in the November 2021 Proposal. As discussed in the November 2021 Proposal, unnecessary and redundant reports and maintaining records were either removed or replaced with improved ways to demonstrate and ensure compliance. Please see the November 2021 Proposal for details on the specific recordkeeping and reporting elements EPA replaced or removed from the fugitive emissions monitoring program.<sup>7</sup> The EPA is finalizing these requirements as proposed, which EPA believes represent a sufficient level of recordkeeping and reporting in order to ensure compliance. These recordkeeping and reporting requirements are also being adopted for affected/designated facilities under the NSPS OOOOb and EG OOOOc.

Regarding well ownership transfers, see response II-18-4 of this Chapter.

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<sup>7</sup> 86 FR 63166 (November 15, 2021).

## **Chapter 19. State, Tribal, and Federal Plan Development for Existing Sources**

### **19.1 Leveraging State Programs**

#### ***19.1.1 State Requirement Equivalency Determination***

Comment: Several commenters (2286-CO APCD, 2315-NYSDEC, 2428-API) express concern with the approach to determining equivalency. In general, the commenters believe that states should be afforded maximum flexibility and request additional consultation. Examples of the comments provided are presented in the following paragraphs.

Commenter (2286-CO APCD) believes that the suggested approach to determining equivalency in the December 2022 supplemental proposal program is unduly narrow for states such as Colorado that have developed and implemented a comprehensive program to regulating and reducing hydrocarbon emissions from the oil and gas industry.

The commenter (2286-CO APCD) appreciates EPA's recognition of Colorado's, and other states, existing oil and gas regulations. The commenter also appreciates EPA's recognition of the need to identify the criteria by which EPA will evaluate state programs for purposes of the state Clean Air Act (CAA) section 111(d) plan.

However, the commenter (2286-CO APCD) notes that Colorado's program has been developed and implemented over the course of the past two decades through rigorous processes inclusive of the meaningful engagement of regulated entities and other community members and includes emission reduction requirements for all the major source categories within the oil and gas sector. The commenter contends that many of the existing federal requirements governing oil and gas, as well as requirements set forth in the proposed supplemental program, follow reduction strategies that Colorado first pioneered to reduce both methane and volatile organic compounds (VOC). In many cases, the commenter notes that the Colorado's requirements are similar to those that EPA is now proposing and for some source categories, Colorado's regulations are substantially more stringent or cover source categories that are not included within the supplemental program, and in a few cases Colorado's regulations could be considered slightly less stringent than EPA's proposal. Further, the commenter asserts that Colorado continues to innovate in this area to further minimize the impact from this industry on ground level ozone concentrations and to meet aggressive state statutory oil and gas methane reduction requirements. For Colorado to continue to innovate and lead over the next several years in developing new strategies to reduce emissions from oil and gas activities, the commenter believes that the state needs to maintain a reasonable degree of flexibility in connection with required equivalency demonstrations for existing programs. The commenter states that being bogged down in rigid one size-fits-all assessments that at the end of the process will provide minimal reduction benefits would not be a responsible utilization of Colorado's resources.

Commenter (2315-NYSDEC) appreciates EPA's proposal to allow those states that already regulate emissions from this sector to leverage existing state rules to meet these requirements.

This will help states avoid the need to expend resources to revise regulations for no additional emissions reductions.

Commenter (2315-NYSDEC) notes that, while the three-step process appears to be adequate, there are some terms that could be interpreted in different ways, such as the format of the standard. The commenter believes that 6 NYCRR Part 203, Oil and Natural Gas Sector (Part 203) is at least as stringent as what is being proposed. However, there is some ambiguity in the alternative methods that makes the determination of equivalency unclear. As such, the commenter requests that EPA work with each state that currently has requirements to address this concern.

Commenter (2315-NYSDEC) also recommends that EPA work with each state that has existing requirements in the development and determination of equivalency. Given the relatively small number of states with existing requirements, the commenter believes that this individual consultation would not require extensive outreach and would provide much-needed clarity to those focused on this issue.

Commenter (2428-API) asserts that EPA must provide more flexibility for approving state programs. The commenter believes that EPA exceeds its authority by seeking to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, the commenter states that EPA would have no choice but to approve the program.

For example, the commenter (2428-API) notes that EPA repeatedly and wrongly asserts that its “presumptive standards” must be used to judge the adequacy of state programs. However, the commenter believes that using EPA’s presumptive standards as a measure of acceptability is wrong because a state’s obligation under CAA section 111(d) is to establish standards of performance based on the best system of emission reduction (BSER).

The commenter (2428-API) asserts that EPA’s “presumptive standards” do not constitute BSER. Rather, the commenter believes that the standards represent EPA’s notion of what emissions standard might reasonably satisfy EPA’s BSER determinations. The commenter argues that the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the “presumptive standard” that EPA thinks is best.

The commenter (2428-API) believes that EPA clearly understands that is what the statute requires. The commenter notes that the EPA itself states that CAA “[s]ection 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA’s emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion” The commenter believes that EPA’s acknowledgment that it is the states’ obligation to determine what measures “best” satisfy EPA’s BSER determination is a

correct statement of the law and contradicts the idea that EPA gets to decide what is “best” and impose that judgment on the states.

Response II-19-1: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

### ***19.1.2 Consideration of other Federal and State Regulations Impacting Oil and Natural Gas Facilities***

Comment: Several commenters (2213-Occidental, 2220-WDEQ, 2241-UT DNR, 2248-NDPC, 2251- NAM, 2257-MOGA, 2258-MSD, 2301-US CoC, 2304-PIOGA, 2308-NSWA, 2428-API, 2429-WOC, 2446-IPAA) assert that states are best suited to regulate emissions. In general, these commenters recommend that EPA refrain from publishing rules that duplicate existing state actions. The commenters recommend that EPA allow maximum flexibility to state agencies and provide details of state actions. Examples of some of the specific comments provided are included in the following paragraphs.

Commenter (2248-NDPC) asserts that additional or duplicative regulations add costs and administrative burden that significantly outweigh any corresponding environmental benefit. The commenter contends that these regulations could disincentivize the industry’s voluntary programs that have a real and measurable positive impact on the environment. The commenter notes that in North Dakota and other regions in the U.S., produced natural gas is associated or dissolved in the crude oil, and cannot be produced independently from each other. The commenter provides that the State of North Dakota already has regulations in place that:

- Require a minimum of 91 percent of the associated gas be captured (not flared).<sup>1</sup> Operators are required to report their gas capture data monthly, and many companies have their own goals that exceed 91 percent. This data is available to the public. The latest report from North Dakota’s Pipeline Authority shows 94 percent gas capture in November 2022 and another 5 percent connected to the gathering system but experiencing constraints on the existing gathering systems.
- Prohibit the venting of natural gas unless it is flared or otherwise controlled as approved by the North Dakota Department of Environmental Quality (NDDEQ).<sup>2</sup>
- Require the control of vapors from storage tanks with the implementation of a control device prior to first production and a control device equipped and operated with an automatic igniter or a continuous burning pilot.<sup>3</sup>

Commenter (2220-WDEQ) states that Wyoming has been recognized as a national leader in oil and gas permitting and emission reductions for many years by EPA and other organizations nationwide. The State’s New Source Review (NSR) permitting program, including its Wyoming-tailored Presumptive-Best Available Control Technology (BACT) guidance, already contains a robust set of requirements that capture VOC emissions and, accordingly, associated methane emissions. Furthermore, the commenter adds that Wyoming’s permitting program has already

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<sup>1</sup> [https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665\\_2.pdf](https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf).

<sup>2</sup> North Dakota Administrative Code, Title 33.1, Article 15, Chapter 7.

<sup>3</sup> Id.

been in compliance with 2012 new source performance standards (NSPS) OOOO and 2016 NSPS OOOOa standards for years. In the November 2021 proposed rule, the commenter notes that the EPA cited Wyoming as one of the “[s]tates (that) have led the way in regulating emissions sources that were not yet subject to requirements under the NSPS OOOOa”. Several other western states are similarly situated.

The commenter (2220-WDEQ) notes that the 2020 Technical Rule allowed the use of specific alternative fugitive emissions standards for VOC emissions for six other state permitting programs, including California and Colorado, for certain provisions of NSPS OOOOa. They explain that these alternative fugitive emissions standards may be used for certain individual well sites or gathering and boosting compressor stations. In the November 2021 proposed rule, EPA allowed these alternative fugitive emissions standards to apply for methane fugitive emissions at well sites and gathering and boosting compressor stations in those six states. The commenter continues that the EPA did not appear to further reference this provision in the supplemental proposal. The commenter requests that EPA consider approving alternative fugitive emissions standards for states like Wyoming that already have robust permitting programs that control VOC and methane emissions. In addition, they request further guidance on how it and other states could receive a similar off-ramp for the requirements specified in the 2022 December supplemental proposal. The commenter explains that this would allow the state and its regulated entities to comply with the rule more effectively without diverting resources from an existing program that provides significant environmental benefits. The commenter notes that the EPA has acknowledged that there are certain circumstances that could warrant potential exemptions and alternative standards, noting on page 74780 of the preamble to the December 2022 supplemental rule:

One commenter provided detailed information about the issues with certain wells in Wyoming. The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to the lack of specific sufficient information.<sup>4</sup>

The commenter (2220-WDEQ) hopes that EPA will consider the tenets of cooperative federalism and provide for constructive dialogues to occur that would help Wyoming establish alternative fugitive emissions standards that facilitate compliance and ultimately provide greater environmental benefits as a result.

Commenter (2304-PIOGA) asserts that existing sources are regulated in Pennsylvania. The commenter states that environmental groups have made much of the fact that existing sources have not been subject to regulation under CAA section 111(d), and they often engage in rhetoric that existing sources are not regulated. However, the commenter reports that all wells are subject to annual mechanical integrity inspections and reports that are filed with the Pennsylvania Department of Environmental Protection (PADEP). The commenter provides that a key aspect of these inspections and reporting focuses on pressure that, despite EPA's unwillingness to acknowledge the relationship between pressure/flow rate and emissions, correlates directly to leaks – or the lack thereof. Additionally, the commenter adds that vertical unconventional wells are also subject to quarterly emission surveying, while horizontal unconventional wells are

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<sup>4</sup> See Document ID No. EPA-HQ-OAR-2021-0317-0955.

subject to even more monitoring for emissions and/or permitting. According to the commenter, to say that conventional wells are unregulated is ridiculous, and contrary to reality.

Commenter (2258-MSD) states that comprehensive and robust regulatory programs and new requirements have been adopted since the onset of significant unconventional natural gas development in Pennsylvania. They explain that new and existing sources are covered by performance measures to identify and limit leaks, with well pads and midstream infrastructure operating under new and revised air quality general permits. Pennsylvania has compiled an inventory of emissions since 2012 and expanded the scope of participating facilities over the years.

The commenter (2258-MSD) recommends that EPA recognize that natural gas development in the U.S., and particularly in the Appalachian Basin, has some of the lowest methane intensity rates in the world. For example, the commenter states that the International Energy Agency recognizes that the U.S. methane intensity of 8 tons (per thousand tons of oil equivalent) is one of the lowest of major oil and natural gas producing countries in the world, lower than China (9), Russia (13), Venezuela (48) and Libya (103). Here in the U.S., the commenter presents that the Appalachian Basin's methane intensity is the lowest of the nine major hydrocarbon producing basins in the entire country.<sup>5</sup>

The commenter (2258-MSD) states that natural gas operators are rightfully proud of their contribution to reducing climate change inducing emissions. Operators have demonstrated this commitment through their voluntary participation in meaningful initiatives such as One Future, American Petroleum Institute's (API's) The Environmental Partnership, the U.S. EPA's Methane Challenge, and the Global Methane Initiative, to name a few. The commenter notes that over 85 percent of their Board members participate in one or more of these initiatives.

Commenter (2257-MOGA) supports EPA's decision to allow individual state's primacy over Emission Guidelines (EG). From the commenter's perspective, all wells are permitted, reviewed, and managed by state agencies to protect the environment, land, surface water, drinking water and residences under each state's current State Implementation Plan (SIP). These agencies have local staff that visit sites, respond to residential concerns, monitor activities, review the state rules, and hold the operators in check regarding all aspects of operations and compliance. The commenter states that correspondence and file reviews of these operations and production volumes are provided to these agencies that are familiar with the field production so any changes, modifications or community intervention can be handled immediately, thus protecting the community. The commenter asserts that Federal inspections and correspondence have historically, not provided quick responses and often allowed problems to magnify into greater, more impactful issues requiring costly long-term solutions.

The commenter (2257-MOGA) expresses concern with EPA's proposed minimum standards for NSPS OOOOb and EG OOOOc. The commenter contends that individual states are better positioned to determine feasible regulations through intimate knowledge of their state's geology, producing horizons, oil and gas chemical characteristics, formation production efficiencies, pooling units, emissions potential, permitting requirements, enforcement regulations and waste

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<sup>5</sup> Clean Air Task Force & Ceres: Benchmarking Methane & Other GHG Emissions (June 2021).

prevention guidelines than the “one-size-fits-all” approach proposed by the EPA at the federal level.

If the EPA continues to pursue a “one-size-fits-all” approach to state level regulations, the commenter (2257-MOGA) requests that the EPA provide a review of each state’s regulatory rules regarding both oil and gas permitting and air quality requirements to ensure that federal oversight does not conflict with individual state regulations. The commenter feels this would ease the concerns of state’s regulatory agencies and the small business oil and gas producers to ensure that the EPA has thoroughly understood each state specific rules and regulations necessary to facilitate proposed EGs with the flexibility for each state to implement their respective rules and regulations with more specificity than a macro-level understanding at the federal level.

Commenter (2446-IPAA) contends that state regulators have experience with the well operations and reservoirs in their state. The commenter believes that, if the proposed regulations were in the form of Control Technique Guidelines (CTG) where the flexibility to design reasonably available control measures (RACM) allows the state to readily address its distinctions, as contemplated by CAA section 111(d), issues could be addressed more effectively. The commenter asserts that ascribing to the CAA section 111(d) obligation to be prescriptive in regulation would be at odds with the intention that it would be applied to a small number of facilities that resulted from the regulation of emissions that were neither criteria pollutants nor hazardous air pollutants (HAP). The commenter states that greenhouse gases (GHG) were never envisioned at the time of the development of the CAA. Now, these EG involve almost one million sources – more when the multiple designated facilities definitions are considered. The commenter notes that at the same time, EPA is proposing interpretations of the language of CAA section 111(d) – particularly the interpretation of remaining useful life and other factors (RULOF) – that handcuff the states flexibility to alter the EPA model regulations in the EG.

Commenter (2213-Occidental) proposes that EPA avoid promulgating duplicative regulations that are inconsistent with state or other Federal regulatory programs. The commenter recommends that a mechanism be included in the NSPS and EG to provide flexibility for states to utilize their programs. The commenter contends that this flexibility would allow operators to focus resources on implementing changes that result in substantive emissions reductions and eliminate any confusion surrounding duplicative requirements.

The commenter (2213-Occidental) has observed how effectively the performance-based approach applied by states has addressed regional differences and expedited technical advances to detect and reduce methane emissions, despite significant increases in activity levels. The commenter explains that there are extensive regulations in place in each state where the commenter operates that take local community, operational and environmental considerations into account to reduce emissions and address unique challenges and situations. Therefore, they urge that any Federal regulations developed complement and not duplicate or complicate compliance with those state regulations. The commenter adds that they work in cooperation with the regulatory agencies and environmental groups where they operate to help develop and implement regulations that produce effective emissions reductions. For example, the commenter has been supportive of ground-breaking regulations in the New Mexico and Colorado rules. In

Colorado, the state's 2022 regulations require significant decreases in GHG emissions at milestones through 2030. In 2021 and 2022, New Mexico finalized its New Mexico Oil Conservation Commission (NMOCD) and New Mexico Environment Department (NMED) rules that reflect the diverse operations, oil and gas formations and types of production conducted in the state.

The commenter (2213-Occidental) points out that these state regulations require significant emission reductions and associated recordkeeping and reporting requirements for pneumatics, tanks, flaring and venting, associated gas and fugitive emissions that have unique frameworks. The commenter supports the non-emitting standard for new pneumatic sources prospectively and the retrofitting of existing natural gas-driven pneumatics over a reasonable time period consistent with leading state rules that consider the variety of factors at play.

If an additional EPA requirement were superimposed on the stringent state requirements, the commenter (2213-Occidental) contends that it would cause confusion and additional regulator and operator burdens with no additional environmental benefit. The commenter expresses concern that the confusion caused by duplicative or conflicting Federal regulations would divert resources from implementing these state regulations that are resulting in significant reductions in emissions.

Commenter (2301-US CoC) recommends that EPA expedite, to the greatest extent possible, the submission and approval processes for states' and Tribes' CAA section 111 (d) plans for existing sources under EG OOOOc (as outlined below).

The commenter (2301-US CoC) asserts that the swift adoption of workable, durable state plans will benefit both the environment and industry by further reducing methane emissions while providing regulatory certainty. The commenter states that allowing states and Tribes the flexibility to use their existing programs is expected to result in more, and more immediate, reductions in methane emissions for the reasons they describe below. As EPA knows, the commenter notes that existing sources will not become subject to direct methane regulation until state plans take effect. Because existing sources represent a far greater percentage of sources, the commenter states that EPA can ensure a greater and more immediate reduction in methane emissions by simplifying and expediting the process for state plan approvals.

Commenter (2308-NSWA) asserts that volunteer efforts and state regulations already exist. The commenter urges EPA to stop the federally driven top-down requirements which they believe do not fit or apply to all sizes of operations and businesses. The commenter adds that no rule adopted by EPA should result in putting oil and gas companies out of business, or significantly changing the economics of the operations. As currently drafted, however, they contend it appears likely to result in just that.

The commenter (2308-NSWA) recognizes the need for a regulatory framework, however notes the important role states have played for many years in overseeing oil and gas operations across the U.S. Virtually since enactment of the 1972 CAA, the commenter reports that states have held the appropriate and cherished lead responsibility for the detailed implementation of the nation's



major environmental laws, which have served as broad guidance from Congress on policing the nation's drinking water and air emissions.

The commenter (2308-NSWA) states that their members are proud of their record of working in partnership with state regulators in protecting the state's lands and waters, as well as key species, as they carry out their operations.

Commenter (2429-WOC) believes that appropriate and timely regulation spurs innovation and creative solutions. The commenter reports that Wyoming was an early adopter of existing source rule requirements in 2015 because of challenges with wintertime ozone conditions in the Upper Green River Basin (UGRB). The commenter notes that Wyoming's leadership and collaboration to address these concerns set the stage to improve winter ozone conditions in the UGRB and resulted in some of the most responsible and innovative operators in the country. The commenter states that today, operators such as Jonah Energy and Purewest Energy are at the forefront of implementing continuous emission detection technologies and using drones and other technology to assist with methane leak detection and repair. Importantly, the commenter reports that these companies are helping to pioneer new markets for differentiated natural gas that will result in less methane emissions and allow them to sell their products to new markets. The commenter contends that in Wyoming, appropriate regulation that levels the playing field across the industry, while also giving operators flexibility to innovate, test, and apply new creative solutions, can be used to spur innovation, and raise industry standards across the board.

Commenter (2428-API) notes that their comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA section 111(d) standard setting criteria, and that EPA cannot approve state programs that do not meet those criteria. The commenter asserts that EPA's proposal violates this principle.

The commenter (2428-API) argues that EPA must provide more flexibility for approving state programs and allow for certain state provisions to be deemed equivalent where it is appropriate to do so. The commenter notes that EPA indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. The commenter adds that, on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state and the possibility that certain state programs will be less stringent. The commenter asserts that EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. According to the commenter, such an inconsistent approach is facially arbitrary. The commenter contends that it is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), the commenter recommends that EPA allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission

monitoring) and other emission control provisions. The commenter (2428-API) recommends that EPA allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical.

Commenter (2241-UDNR) encourages EPA to develop regulations that are consistent with state land use plans and policies. The commenter supports EPA recognition of states actions and recommends that EPA engage with states when conflicts arise. The commenter notes that the December 2022 proposal “specifically recognizes states’ and tribes’ unique roles, stating that “some forward-looking states have their own regulations for methane emissions from the oil and gas industry, and EPA’s proposal provides states the opportunity to leverage their existing programs or develop new programs that are at least as effective as the presumptive standards.”<sup>6</sup> The commenter appreciates the recognition of certain state’s attempt to be proactive in regard to methane emissions, and requests that its State Resource Management Plan (SRMP) (and other relevant code) be given appropriate consideration as the EPA moves forward with its proposal.

The commenter (2241-UDNR) notes that when Federal agencies are preparing an Environmental Impact Statement (EIS) under the Council on Environmental Quality’s (CEQ) regulations for the National Environmental Policy Act (NEPA), the “environmental consequences” section of the EIS must include a discussion of “[p]ossible conflicts between the proposed action and the objectives of Federal, regional, State, Tribal, and local land use plans, policies and controls for the area concerned.”<sup>7</sup> While the EPA’s December 2022 proposed rule is not an EIS, the commenter recommends that EPA strive for consistency with the land use plans, policies, and controls from state, tribal and local governments, and in the spirit of the CEQ regulations, discuss possible conflicts with those plans, policies and controls. For example, the EPA should strive for consistency with state law, and the state’s Resource Management Plan.<sup>8</sup> The commenter recommends that EPA consider similar plans and policies of local governments, such as county governments that will be particularly impacted by the EPA’s proposed rule, with conflicts identified and discussed. In 2018, the state adopted a State Resource Management Plan (SRMP) and all twenty-nine counties in the state have adopted County Resource Management Plans (CRMPs)<sup>9</sup>. The commenter reports that these RMPs include policies for many aspects of public land management, including those related to oil and natural gas, as well as energy infrastructure development.

The commenter (2241-UDNR) reports that both SRMP and the State CRMPs contain numerous provisions relating to responsible natural resources, climate, and environmental quality issues. These provisions are developed at a local level and therefore reflect the desires, policy, and preferences of local populations. The commenter recommends that EPA consider these SRMPs

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<sup>6</sup> See <https://www.epa.gov/system/files/documents/2021-11/2021-oil-and-gas-proposal.-overview-fact-sheet.pdf>.

<sup>7</sup> 40 CFR 1502.16(5).

<sup>8</sup> Utah State Resource Management Plan (Utah SRMP), pp. 9, available at [https://storymaps.arcgis.com/collections/81d4406668e34acca4d98275ee41cd07\(2022\)](https://storymaps.arcgis.com/collections/81d4406668e34acca4d98275ee41cd07(2022)).

<sup>9</sup> PLPCO, Resource Management Plans by County, Utah’s Public Lands Policy Coordinating Office, available at <https://utah-resource-management-planning-plpco.hub.arcgis.com/pages/county-management-plans> (2022).

and CRMPs to ensure that decisions are made consistent with local plans. The commenter recommends that these plans (not only Utah's but nationwide) be consulted going forward as part of the Bureau of Land Management (BLM) efforts to include a wide range of partners, stakeholders, landowners and producers in future natural gas and environmental justice related decisions.

In addition to the policies found in the Utah SRMP, the commenter (2241-UDNR) reports that Utah has also adopted law enshrined in Utah Code establishing energy zones along with management and land use priorities for said zones. The relevant zones for purposes of this comment letter include the San Juan County Energy Zone,<sup>10</sup> the Uintah Basin Energy Zone,<sup>11</sup> and the Green River Energy Zone.<sup>12</sup> Together, these three energy zones contain almost exclusively all the natural gas production in the State of Utah. The commenter reports that all three statutes governing these three energy zones have provisions and directives for the management of federal land within these zones to achieve productive natural gas development. For example, within the Uintah Basin Energy Zone, Utah Code states that:

(4) The state supports:

(a) efficient and responsible full development of all existing energy and mineral resources located within the Uintah Basin Energy Zone, including oil, oil shale, natural gas, oil sands...; and

(b) a cooperative management approach among federal agencies, state, and local governments to achieve broadly supported management plans for the full development of all energy and mineral resources within the Uintah Basin Energy Zone.

(5) The state calls upon the federal agencies who administer lands within the Uintah Basin Energy Zone to:

(a) fully cooperate and coordinate with the state and with Daggett, Uintah, and Duchesne Counties to develop, amend, and implement land and resource management plans and to implement management decisions that are consistent with the purposes, goals, and policies described in this section to the maximum extent allowed under federal law...<sup>13</sup>

The commenter (2241-UDNR) states that the Utah SRMP promotes responsible fossil fuel energy generation, fossil fuel development, and related infrastructure, and Utah Code establishes Energy Zones with directives to develop all energy and mineral resources within the zone. The commenter requests that EPA consider and coordinate with the state's RMP and relevant State

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<sup>10</sup> Utah State Code Annotated § 63J-8-105.2.

<sup>11</sup> Utah State Code Annotated § 63J-8-105.5.

<sup>12</sup> Utah State Code Annotated § 63J-8-105.7.

<sup>13</sup> Utah State Code Annotated § 63J-8-105.5(4)-(5); see also Utah State Code Annotated § 63J-8-105.2(4)-(5) and Utah State Code Annotated § 63J-8-105.7(4)-(5) (The statutes governing the San Juan County Energy Zone and Green River Energy Zone contain almost identical verbiage to that quoted/cited herein regarding the Uintah Basin Energy Zone).

Code. Further, the commenter requests that the EPA ensure that current and future actions taken in furtherance of the proposed rule remain consistent with said plans and energy zones to the maximum extent possible.

Commenter (2223-TAEP) urges EPA to allow state partnerships to flourish and resist the temptation to mandate federally driven top-down requirements which do not fit or apply to all sizes of operations and businesses. The commenter states that new, costly, and burdensome federal requirements on producers are unnecessary and may have the opposite of the intended result. The commenter asserts that the role of the states and their various regulatory structures cannot be overstated. Virtually since enactment of the 1972 CAA, states have held the appropriate lead responsibility for the detailed implementation of the nation's major environmental laws, which have served as broad guidance from Congress on policing the nation's drinking water and air emissions. In Texas, the commenter and other operators have ongoing direct interaction with the agencies charged with various facets of regulation, most notably the Railroad Commission of Texas and the Texas Commission on Environmental Quality. The commenter asserts that the regulatory structure is effective, leading to reduced emissions of GHGs including methane over time.

Response II-19-2: Once the EPA establishes NSPS for a particular source category, the EPA is required in certain circumstances to issue EG to reduce emissions from existing sources in that same source category. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for CAA section 111(d) as well as through specific EG. Please see section IV.A. of the final preamble of additional discussion on EPA's statutory obligations under CAA section 111. Furthermore, to be clear, the final EG OOOOc in no way impacts states' ability to regulate sources under state law. Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble. Please see Volume 1 Chapter 19 Response I-19-11 that discusses that the AMEL provision in the CAA has been applied only in the context of NSPS issued under CAA section 111(b). Please see preamble section XIII.D, E, F, and G for discussion on the required components of approvable state plans, timing of state plan submission and compliance schedules, EPA's action of state plans and promulgation of federal plans, and Tribes and the planning process.

Commenters discuss the value of voluntary programs. Although the EPA recognizes and commends the value of these programs, such voluntary efforts are not legally binding and do not alter the EPA's own statutory responsibility to regulate methane emissions from this sector under the CAA. Moreover, as the information and analysis reflected in this final rulemaking make clear, there is still considerable need and opportunity to further reduce methane emissions from the industry.

Comment: Commenter (2166-ODNR) states that during the development of the NSPS requirements, the EPA stated that some facilities will be subject to current or future requirements of the Department of Interior's BLM rules covering production of natural gas on federal lands.

The commenter also reiterates that the EPA discussed its ongoing dialogue with BLM during the development of the proposals to align requirements and to minimize confusion and unnecessary burden on the part of the owners and operators. The commenter asserts that this dialogue should include or take into consideration existing state regulatory agencies and rules to prevent confusion and unnecessary burden on owners, operators, landowners, and state regulators.

Several commenters (2402-DGCC, 2363-CEMC, 2448-PCPBC) urge the EPA collaborate closely with other federal departments that are also regulating methane emissions. The EPA has an opportunity to harmonize a move to more effective and innovative measurement-based methane controls by coordinating the proposed December 2022 supplemental rule with other federal regulations from the BLM, the Securities and Exchange Commission, the Department of Energy (DOE), the Department of the Treasury (DOT), the Federal Acquisition Regulatory Council, and the Pipeline Hazardous Materials Safety Administration (PHMSA), to avoid duplicative or conflicting regulatory regimes. The commenters suggest that this will accelerate the deployment of advanced technologies and continuous monitoring, reduce compliance costs, enable robust energy production, ensure greater reductions of methane and, importantly, minimize duplicative compliance requirements.

Commenter (2166-ODNR) is concerned with portions of the draft rule that state citizens would be authorized to enter private lands for emissions measurements. Most wells in Ohio are located on private property, and the guidelines include no language regarding how Ohioans, law enforcement, or state regulators will know who is authorized to be on the property. There are no standards established for calibration of equipment that ensure readings are measured correctly or for remedies landowners or operators may take should emissions be read incorrectly. Additionally, there is no language regarding where liability rests should injury to persons or property occur.

Commenter (2166-ODNR) states gas leaks are currently regulated in Ohio, as state law prohibits owners of wells from allowing the wells to leak fluids or gases. No matter the reason (defective casing, tubing or packing leaks, defective tubing, pipe/fitting connection thread leaks, corroded piping, stuffing box leaks, defective casing below grade), the commenter has the authority to act. Operators are required to immediately repair casing, correct inadequacies, or plug and abandon the well. Additional redundant regulations on owners and operators are an unnecessary burden and would create confusion.

Response II-19-3: Please see section VI.A in the final preamble discussing related state and federal actions. EPA notes that certain Federal agencies also regulate aspects of the oil and natural gas industry pursuant to their own authorities. For example, BLM specifically has the express authority and responsibility to regulate both for the prevention of waste and the protection of the environment for operations on Federal and Indian lands. This responsibility includes promulgating regulations to reduce the waste of natural gas from oil and gas leases administered by the BLM.

Please refer to RTC Volume 2 Chapter 14 for Super Emitters which responds to the commenters' concern regarding unauthorized access to oil and gas operations. Specifically, we have revised

the Super Emitter Program to require EPA approval of methane detection technology and to include requirements that certified third parties cannot access approved applicable sites and doing so would lead to the removal of their certification. Lastly, please see section IV.A. of the final preamble of additional discussion on EPA's statutory obligations under CAA section 111. Furthermore, to be clear, the final EG OOOOc in no way impacts states' ability to regulate sources under state law.

### ***19.1.3 Lack of Enforcement of State Rules***

Comment: Commenter (2270-Lucero) notes that rules without strong enforcement mechanisms are ineffectual. The commenter reports that New Mexico adopted new methane rules which went into effect in the summer of 2022. The commenter states that the Governor touted these new rules at the 27th Conference of the Parties to the United Nations Framework Convention on Climate Change (COP27), saying that New Mexico is leading the country in regulating methane emissions, where the goal is to reduce methane emissions by over 851 million pounds annually.<sup>14</sup>

However, the commenter (2270-Lucero) complains that as late as January 2023, the evidence shows that lack of enforcement allows the oil and gas industry to keep emitting.<sup>15</sup> The commenter reports that the NMED takes its mission to hold polluters accountable seriously but, according to NMED secretary James Kenney, does not have the resources it needs to assure compliance and hold polluters accountable, and that chronic underfunding has persisted for years.<sup>16</sup>

Response II-19-4: Please see section XIII of the final preamble that discusses the required components of an approvable state plan submission. Specifically, the administrative completeness criteria require that the state's plan include a formal submittal letter and a copy of the actual state regulations themselves, as well as evidence that the state has legal authority to adopt and implement the plan, actually adopted the plan, followed state procedural laws when adopting the plan, gave public notice of the changes to state law, held public hearing(s) if applicable, and responded to state-level comments. For a detailed description of what the state plan must include in terms of evidence that the state has legal authority to adopt and implement the plan, see 40 CFR 60.26a. The technical criteria require that the state's plan identify the designated facilities, the standards of performance, the geographic scope of the plan, monitoring, recordkeeping and reporting requirements (both for designated facilities to ensure compliance and for the state to ensure performance of the plan as a whole), and compliance schedules.

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<sup>14</sup> <https://www.env.nm.gov/wp-content/uploads/2022/04/2022-04-14-COMMS-New-Mexico-adopts-nationally-leading-oil-and-gas-emissions-rule-Final.pdf>.

<sup>15</sup> <https://www.hcn.org/articles/energy-industry-new-mexicos-new-pollution-rules-leave-oil-and-gas-operators-to-police-themselves>.

<sup>16</sup> *Id.*

## 19.2 Types of Equivalency Evaluations

### *19.2.1 Total Program Evaluation*

Comment: Several commenters (2249-NACAA, 2286-CO APCD, 2296-NMED, 2326-AXPC, 2390-NMOGA, 2410-CA AG et al, 2446-IPAA, 2301-US CoC) support EPA's use of the total program evaluation tool to evaluate equivalency of existing state programs. In general, commenters recommend that EPA allow maximum flexibility to allow states to continue with existing programs. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (2286-CO APCD) believes that the total program evaluation tool can be employed, with appropriate guardrails, to both ensure significant emission reduction opportunities will move forward while not disrupting effective state programs that are already in place.

The commenter (2286-CO APCD) recommends that EPA recognize that a federal mandate to change existing state programs is not as simple as modifying existing regulatory requirements. They explain that states like Colorado have put considerable effort into developing the implementation structures necessary to ensure that their regulatory requirements achieve the expected emission reductions. The commenter believes that requiring states to modify their programs based on a narrow conception of equivalency will undermine implementation processes and practices that have been developed over many years and can lead to less effective regulation. While this may be appropriate in some circumstances, in cases where states have developed a robust program that in totality achieves greater reductions than the EG, states should be required to adopt new requirements for a particular source category only in the following circumstances: 1) where the state program does not include any reduction requirements for a particular source category; or 2) the state does have reduction requirements for a particular source category but those requirements achieve significantly less emission reductions than the requirements set forth in the EG relative to the overall emission reductions from the oil and gas sector achieved by the state program. Absent these circumstances, the commenter asserts that the state should retain the flexibility necessary to continue with its current program, provided, of course, that the state can demonstrate that the overall program can achieve comparable emission reductions to the EG.

In addition to these common-sense limitations on when changes to existing successful programs can be mandated, the commenter (2286-CO APCD) recommends that the final rule provide additional flexibility to states that can demonstrate overall program equivalency as it pertains to existing state monitoring, recordkeeping, and reporting requirements. Such states, and the operators within these states, have invested heavily in systems that collect, track, report, and receive data to show compliance with emission reduction requirements. The commenter contends that mandating different requirements to match the EG will be costly, create confusion, and undermine the effectiveness of existing programs. The commenter acknowledges that requiring changes to existing monitoring, recordkeeping, and reporting requirements could be warranted under appropriate circumstances notwithstanding the associated cost and confusion. The commenter requests that these circumstances be limited, and that the final rule provide flexibility to states that can demonstrate overall program effectiveness. Specifically, the commenter

requests that the final rule provide that if a state demonstrates overall program equivalency, changes or additions to existing monitoring, recordkeeping, and reporting provisions only be required where the existing provisions are substantially inadequate to ensure compliance with the associated emission reduction requirements.

Similarly, commenter (2326-AXPC) requests that EPA allow states to leverage existing state programs through submittal of total program evaluations to demonstrate equivalency with EG OOOOc. The commenter contends that precluding states from making a programmatic equivalency determination – by requiring EPA’s source-by-source approach – serves as a disincentive to state rulemaking. Over the past decade, the commenter notes that states like Colorado and New Mexico have expended many resources, time, and effort to promulgate new oil and gas regulations covering the same designated facilities as EPA proposes to regulate under EG OOOOc. The commenter notes that EPA’s proposal relies in large part upon standards already in place in these states. If EPA requires states to demonstrate equivalency on a source-by-source basis, rather than through a programmatic emissions reduction demonstration, the commenter states that EPA would be applying a one-size-fits all approach to state regulation in contradiction of the cooperative federalism principles inherent throughout the CAA and specifically enumerated in CAA section 111(d). Further, the commenter believes that EPA’s source-by-source equivalency approach will stifle progressive state rulemaking, as those states would be less likely to expend the significant resources to promulgate new rules only to have EPA swoop in and set aside well-thought state programs.

Commenter (2249-NACAA) recommends that EPA consider previous regulatory investments and existing State Implementation Plan (SIP) approvals. The commenter states that EPA has demonstrated experience with creating a streamlined equivalency through the implementation of its NSPS OOOOa provisions since 2016. States that have rules or well-developed proposals have already gone through robust public processes and rulemakings and programs included in these equivalencies are frequently a part of an approved SIP. Inasmuch as the forthcoming implementation rule proposal seeks to accommodate state programs, the commenter recommends that EPA consider regulatory actions and timelines required in those states and integrate flexibility into the rule that accommodates them.

The commenter (2249-NACAA) recommends that EPA provide more clarity and specificity in its articulation of Steps 2 and 3 of the equivalency determination, particularly offering clarity about the approval of alternative technologies. The commenter recommends that EPA establish guidance and work with each state that has developed methane regulations - the number of affected agencies is very reasonable, and this would pose little burden on EPA. In addition, they suggest that ongoing resources be devoted to offering cooperative and consultative technical support to these states as EPA determines equivalency. The commenter recommends that EPA be consistent across different regions in these determinations. However, EPA ultimately resolves these issues, the commenter asserts that EPA must be clear in its eventual guidance and offer a streamlined process for equivalency to give state and local agencies a high degree of certainty in leveraging their existing programs.

Commenter (2296-NMED) asserts that EPA must provide states with existing oil and gas regulations an option to demonstrate the equivalency of their existing programs against EPA’s



proposed EG. The commenter notes that state regulatory agencies have limited capacity and resources to implement and enforce regulations. The commenter believes that requiring these overburdened agencies to implement and enforce two redundant regulations jeopardizes the regulatory agency's effectiveness and has not been justified in the EPA proposal. Until EPA can demonstrate the scientific basis for this redundant set of requirements, the commenter believes that the requirement to adopt identical EGs is redundant, unnecessary, and an extremely poor use of state regulatory agencies' limited staffing resources.

The commenter (2296-NMED) is concerned that EPA's current proposal provides New Mexico no option to demonstrate equivalency of Part 50, despite the rule being a nation leading oil and gas regulation. The commenter believes that, as proposed, the criteria to demonstrate equivalency is unworkable, inflexible, and short-sighted. The commenter explains that New Mexico just completed a multi-year comprehensive rulemaking process for a nation leading regulation covering both new and existing oil and natural gas sources, which will result in significant emissions reductions of methane and VOC. The commenter notes that requiring states to adopt EG for existing sources, when several states have rigorous emission control requirements under their current programs on the books, means states and operators will have to implement and enforce two differing sets of regulatory requirements that cover tens of thousands of identical sources. The commenter contends that disregarding New Mexico's robust existing regulations and requiring resource-strapped regulatory agencies to go through another rulemaking will result in serious delays and jeopardize our ability to submit a timely SIP. The commenter reports that New Mexico has one of the most time-consuming and lengthy rulemaking procedures, which are more stringent than the federal government and other regulatory agencies. It appears that no consideration has been given to state's differing rulemaking requirements, even though states bear the burden of following the regulations within the federal government's unrealistic timelines.

The commenter (2296-NMED) believes that it is incumbent upon EPA to consider the above points and to allow equivalency demonstrations for states and have a streamlined process for the adoption of states' existing rules. The commenter also urges the EPA to provide a streamlined demonstration of equivalency if state rules already require meaningful, cost-effective GHG and VOC emission reductions.

Commenter (2410-CA AG et al) reiterates their support for flexibility for states in designing their CAA section 111(d) plans if states can demonstrate equivalent or better emission reductions. The commenter provides their comments on EPA's reconsideration of the prior Administration's interpretation limiting state compliance choices. The commenter notes that EPA proposes to interpret CAA section 111(d) to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards. The EPA explains that this approach would necessitate reversing its legal interpretation in the Affordable Clean Energy (ACE) rule that "each state establish for each source a standard of performance that reduces that source's emissions, and to preclude the type of compliance flexibility that EPA is now proposing." On that basis, EPA precluded the use of emissions averaging or trading to comply with the 2019 ACE Rule. The commenter notes that the D.C. Circuit cited this limit on state plan flexibility as one of the reasons why the ACE rule was unlawful.<sup>17</sup> Although the

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<sup>17</sup> See *American Lung Ass'n v. EPA*, 985 F.3d 914, 957–58 (D.C. Cir. 2021).

Supreme Court reversed the D.C. Circuit, holding that the ACE's rule's repeal of the Clean Power Plan was lawful under the major questions doctrine, the commenter notes that the Supreme Court did not rule on the statutory interpretation EPA advanced in favor of the ACE rule, including the limit on compliance flexibility.<sup>18</sup>

The commenter (2410-CA AG et al) notes that in the Supplemental Proposal, EPA explains that it has changed its view set forth in the ACE rule that constrained compliance flexibility. As EPA notes, there is no statutory language in CAA section 111 that limits the flexibility of states in determining which measures will best achieve compliance with the emissions guideline. To the contrary, the commenter contends that flexibility is consistent with CAA section 111's language, which focuses on the aim of achieving sufficient pollution reduction, not the way that reduction is accomplished. Specifically, they note that CAA section 111(a)(1) provides that state plans are to include standards of performance for regulated facilities that "reflect[] the degree of emission limitation achievable through application of the best system of emission reduction."<sup>19</sup> In addition, the commenter notes that section 116 of the CAA preserves the "right of any State . . . to adopt or enforce . . . any standard or limitation respecting emissions of air pollutants" as long as such standard or limitation is at least as stringent as one "in effect under an applicable implementation plan or under section 7411" of the statute.<sup>20</sup> The commenter believes that although there may be instances in which emissions averaging or trading potentially could run afoul of this structure (e.g., by enabling the creation of pollution "hot spots"), such a concern would not arise in the context of EGs that require limiting GHG emissions, such as carbon dioxide (CO<sub>2</sub>) or methane.<sup>21</sup> Therefore, the commenter supports EPA's change in interpretation as justified in this rulemaking.<sup>22</sup>

The commenter (2446-IPAA) notes that EPA raises then dismisses the possibility of states getting plan approval for a mix of regulations that embrace parts of the EG OOOOc proposal and supplementing those elements with other regulations that produce a comparable overall methane management program. However, in its proposed general revisions to CAA section 111(d), EPA supports programs for compliance flexibility including trading and other mechanisms that provide for state flexibility. The commenter recommends that EPA not preclude such options under EG OOOOc plan development.

The commenter (2301-US CoC) notes that many states have established methane programs already in place that can and should be leveraged to satisfy CAA section 111(d) obligations. To this end, the commenter believes that states relying on their existing methane and VOC programs should be authorized to include a different form of standard in their plans so long as they demonstrate the equivalency of such standards to the final EGs in terms of achieving roughly the same overall reduction in methane emissions. The commenter therefore supports EPA's proposal to interpret CAA section 111 to authorize states to establish standards of performance for their

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<sup>18</sup> See *West Virginia v. EPA*, 142 S. Ct. 2587, 2615–16 (2022).

<sup>19</sup> 42 U.S.C. § 7411(a)(1).

<sup>20</sup> *Id.* § 7416.

<sup>21</sup> See *Amer. Lung Ass'n*, 985 F.3d at 958.

<sup>22</sup> As EPA notes, the commenter states that it is also proposing to change the ACE rule interpretation in the context of its section 111(d) implementing regulations, which establish the default procedures and requirements for all state plans under section 111(d). 87 Fed. Reg. at 74,813. Many of the States and Cities intend to address this topic in their comments on that proposed rule as well.

sources that, in the aggregate, would be equivalent to the EG presumptive standards. Such flexibility is, as EPA observes, consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion.

In addition, the commenter (2301-US CoC) recommends that EPA allow states to establish that their existing programs are equivalent to the EG presumptive standards based on a total program evaluation. Total program evaluations would, as EPA acknowledges, reduce burdens across the board by (1) mitigating the need for states to overhaul or scrap existing methane programs in order to meet the presumptive standards and (2) reducing compliance burdens on owners and operators, who would not need to comply with two different sets of regulations. While the commenter understands EPA's concerns regarding certain state regimes, the commenter encourages the EPA to entertain proposals from states that can show that their programs achieve emission reduction benefits equivalent to the EGs. The commenter believes that using existing state and/or Tribal programs as a starting point will also help to ensure that the approval process for state plans is not unnecessarily delayed by forcing states to make unnecessary revisions to existing programs. This, in turn, the commenter believes, will reduce the burden on operators who are already complying with these state regimes and ensure that there is direct regulation of methane from existing sources on a shorter timeframe.

Response II-19-5: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

Comment: Commenter (2390-NMOGA) requests that EPA allow states to leverage existing state programs by submitting total program evaluations to demonstrate equivalency to EG OOOOc.<sup>23</sup> The commenter contends that total program evaluations is consistent with CAA section 111(d) and will promote, rather than disincentivize, future state efforts to adopt state programs. The commenter provides the following details to justify their request.

*CAA section 111(d) provides states with flexibility to determine how to comply with the EGs, including through the averaging of emissions across sources.* The commenter (2390-NMOGA) agrees with EPA that CAA section 111(d) “authorize[s] states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards.”<sup>24</sup> The commenter adds that they believe that EPA's interpretation is consistent with—and required by—the statutory language and the D.C. Circuit's decision in *American Lung Association v. EPA*. The commenter asserts that EPA should not foreclose the flexibility provided under the CAA and “categorically exclude[]” states from relying on emission averaging across source categories to demonstrate equivalency.<sup>25</sup>

The commenter (2390-NMOGA) contends that allowing states to submit total program evaluations will eliminate unnecessary administrative burdens, achieve equivalent emission reductions, and incentivize progressive state efforts to achieve future emission reductions. The commenter encourages EPA to allow states to leverage existing state programs and submit total

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<sup>23</sup> By referencing equivalency (including total program equivalency), the commenter recognizes that other factors may apply in particular circumstances that would not require a demonstration of equivalency.

<sup>24</sup> 87 Fed. Reg. 74,702, 74,812 (Dec. 6, 2022).

<sup>25</sup> *Am. Lung Ass'n*, 985 F.3d at 957.

program evaluations “that, in the aggregate,” demonstrate compliance with EG 0000c. The commenter asserts that EPA’s proposal to preclude states from relying on emission averaging across source categories to demonstrate equivalency will prevent states from effectively leveraging existing state programs, require states with existing, comprehensive regulatory programs to undertake additional rulemakings in order to achieve source-by-source identity, disincentivize progressive state efforts to control emissions, and disincentivize operators (such as those in Colorado and New Mexico) from working with the state on the development of new regulatory requirements.

The commenter (2390-NMOGA) reports that New Mexico recently invested significant time, energy, and resources to develop a progressive, comprehensive regulatory regime aimed at reducing VOCs and (as a co-benefit) methane emissions from oil and natural gas operations in the upstream, transmission, and storage segments. The commenter reports that in April 2021, the New Mexico Oil Conservation Division amended its statewide regulations to require operators to meet a statewide annual 98 percent natural gas capture from the oil and natural gas industry by 2027, making New Mexico an environmental leader by promulgating one of the most ambitious methane rules in the country.<sup>26</sup> The commenter reports that in July 2022, the NMED adopted regulations to reduce ozone precursors from the oil and gas sector (Ozone Precursor Rules). The Ozone Precursor Rules were adopted with the understanding that the rules “will have the co-benefit of reducing methane emissions because methane is released along with volatile organic compounds in oil and gas operations.”<sup>27</sup>

The commenter (2390-NMOGA) emphasizes that the effort, time, and resources that went into the promulgation of NMED’s Ozone Precursor Rules cannot be understated. The commenter provides details of the consultation process. The commenter notes that NMED undertook an extensive stakeholder and public outreach process starting in summer 2019, during which it convened a Methane Advisory Panel (MAP) consisting of technical stakeholders focusing on processes and equipment associated with oil and gas exploration, production, gathering, and processing.<sup>28</sup> The commenter notes that the MAP met every other week over a four-month period and covered technical topics related to controlling VOC and methane emissions from equipment and operations employed in the oil and natural gas sector.<sup>29</sup> The preliminary pre-petition draft of the proposed rules was released on July 20, 2020 for the purpose of soliciting public and stakeholder input.<sup>30</sup> On September 20, 2020, the public comment period closed and the commenter had received 524 written comments on the proposed rule.<sup>31</sup> The rulemaking hearing process commenced on May 6, 2021, and the hearing was held between September 20 through October 1, 2021.<sup>32</sup> The commenter notes that twenty-seven parties, including environmental conservation groups, environmental justice groups, a non-profit group

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<sup>26</sup> See 19.15.27 and 19.15.28 NMAC.

<sup>27</sup> State of New Mexico, Environmental Improvement Board, Statement of Reasons and Final Order, In the Matter of Proposed New Regulation 20.2.50 NMAC (“Ozone Precursor Rules, Final Order”), 10 (June 27, 2022).

<sup>28</sup> Id. at 10.

<sup>29</sup> Id. at 10-11.

<sup>30</sup> Id. at 11.

<sup>31</sup> Id.

<sup>32</sup> Id. at 1.

representing the Navajo Nation, and industry associations, participated in the rulemaking.<sup>33</sup> The parties filed technical testimony, rebuttal statements, surrebuttal statements, closing arguments, and numerous exhibits—and presented hours of testimony during the rulemaking hearing. 125 people provided non-technical public comments throughout the ten-day hearing.<sup>34</sup>

Following an extensive post-hearing process, the commenter (2390-NMOGA) provides that the New Mexico Environmental Improvement Board conducted lengthy deliberations at its March 10 – 11 and April 11 – 13, 2022 meetings.<sup>35</sup> After the rulemaking, the Board reopened deliberations again on May 27, 2022.<sup>36</sup> The rule was published on July 26, 2022, and became effective August 5, 2022.<sup>37</sup>

The commenter (2390-NMOGA) asserts that EPA’s proposal to preclude states from submitting total program evaluations disregards the efforts made by New Mexico, and the numerous stakeholders that participated in the rulemaking, to adopt rules that will result in significant emissions reductions of VOCs and methane. The commenter believes it will disincentivize states from undertaking similar efforts in the future.

The commenter (2390-NMOGA) notes that New Mexico will now be required to do a line-by-line comparison of its regulations against EG OOOOc and undertake yet another extensive rulemaking effort to adopt new regulations for every instance where New Mexico’s regulations are not identical to EPA’s for a particular designated facility. And this will be required even if New Mexico can demonstrate that its existing program achieves equal or greater emission reductions, in the aggregate, than EG OOOOc. The commenter believes that EPA’s proposal to require source-by-source equivalency and impose an additional administrative burden on states with existing, comprehensive regulatory programs also ignores the fact that EPA has both promoted and learned from many of these programs. The commenter adds that states and EPA have relied on existing state programs in the promulgation of their own standards.

The commenter (2390-NMOGA) notes that in EPA’s November 15, 2021, proposal for NSPS OOOOb and EG OOOOc, EPA reviewed Colorado’s regulatory program, as well as New Mexico’s then proposed rules, to identify potential regulatory options that could be considered BSER. The commenter further notes that EPA explicitly acknowledged that Colorado has “led the way in regulating emissions sources that were not yet subject to requirements under the NSPS OOOOa.” EPA points to Colorado’s program as a leading example in emission reduction regulations for best management practices (BMPs) to minimize hydrocarbon emissions and for

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<sup>33</sup> Id. at 2.

<sup>34</sup> State of New Mexico, Environmental Improvement Board, Hearing Officer’s Report, In the Matter of Proposed New Regulation 20.2.50 NMAC (“Ozone Precursor Rules, Hearing Officer’s Report”), 8 – 9. (Feb. 24, 2022), <https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/03/2022-02-24-EIB-21-27-Hearing-Officers-Report-pj.pdf>.

<sup>35</sup> Ozone Precursor Rules, Final Order at 8.

<sup>36</sup> Id.

<sup>37</sup> Id.

reducing hydrocarbon and VOC emissions from storage vessels. And EPA relied on existing state programs when it adopted NSPS OOOOa.<sup>38</sup>

The commenter (2390-NMOGA) notes that EPA relied heavily on Colorado’s standards when adopting its rules. The commenter adds that the NMED’s Ozone Precursor Rules for engines and turbines, control devices, leak detection and repair (LDAR), natural gas well liquids unloading, glycol dehydrators, hydrocarbon liquids transfers, pigging operations, pneumatic controllers, pneumatic pumps, storage vessels, and workover operations, are either identical to or based on similar rules and standards in Colorado.<sup>39</sup> The commenter states that now EPA is telling New Mexico (and Colorado) that despite these efforts, the state will need to undertake additional rulemaking to prove identity, rather than equivalency.

The commenter (2390-NMOGA) asserts that EPA’s proposal disincentivizes states from moving forward with adopting or strengthening their own state programs—full stop. According to the commenter, states will be less inclined to endure the administrative costs and burden of conducting state rulemakings if EPA will ultimately adopt superseding EGs and require states to undergo further rulemaking to demonstrate source-by-source identity. The commenter notes that EPA recognizes in the proposed rules that “allowing for total program equivalency could, in theory, reduce burden on states by allowing states with programs to rely more on those programs for their state plan submittal without needing to revise standards for specific designated facilities in order to match the presumptive standards.” But EPA “entirely fail[s] to consider an important aspect of the problem,” the fact that the increased administrative burden will lead to emission disbenefits by discouraging state efforts to adopt independent, progressive regulations.<sup>40</sup> By EPA’s own estimate, without existing state programs in place, like New Mexico’s, the process to develop and implement will take at least three years, with emission benefits not realized until 2026, or later.<sup>41</sup> According to the commenter, this is on top of the fact that the initial proposal to begin this rulemaking was published in November 2021. The commenter contends that EPA should not, and cannot, ignore the impact its proposal to preclude total program evaluations will have on future state efforts to reduce emissions in the absence of federal guidelines.<sup>42</sup>

*EPA’s proposal to disallow states from submitting total program evaluations is unreasonable and unsupported.* The commenter (2390-NMOGA) states that the CAA provides states with flexibility in adopting state programs that satisfy the requirements of CAA section 111(d)<sup>43</sup> as acknowledged by EPA in the preamble to the proposed rules. The commenter believes that this interpretation is supported by the legislative history of the Act. The commenter believes that EPA’s proposal to preclude states from submitting total program evaluations is inconsistent with the flexibility and role Congress intended to provide states under the Act.

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<sup>38</sup> See e.g., 85 Fed. Reg. 57,398, 57,424 (Sept. 15, 2020) (EPA reviewed Colorado’s and Wyoming’s state rules in developing the proposed requirements for reducing methane and VOC fugitive emissions at well sites).

<sup>39</sup> 4 Ozone Precursor Rules, Final Order at 90, 135, 148, 185, 192, 204, 213, 223, 249, 260.

<sup>40</sup> *Motor Vehicle Mfrs. Ass’n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

<sup>41</sup> EPA, Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, EPA-HQ-OAR-2021-0317, 10 (Nov. 2022).

<sup>42</sup> E.g., *Motor Vehicle Mfrs. Ass’n of U.S., Inc.*, 463 U.S. at 43.

<sup>43</sup> See *Am. Lung Ass’n*, 985 F.3d at 957.

During the 1970 amendments to the CAA, the commenter (2390-NMOGA) reports that a Senate bill proposed section 114 which would have required the establishment of national emission standards for “selected air pollution agents.”<sup>44</sup> Section 114 was rewritten in conference to become CAA section 111(d).<sup>45</sup> In 1975, shortly after the CAA was amended, EPA adopted the regulations implementing section 111(d). EPA largely attributed the rewriting of section 114 in conference to CAA section 111(d) to be the result of two Congressional decisions: “(1) To adopt a technology-based approach similar to that for new sources; and (2) to give States a greater role than was provided in section 114.”<sup>46</sup> The point: for states to “have primary responsibility for developing and enforcing control plans under section 111(d).”<sup>47</sup> At the time, the commenter states that the EPA interpreted CAA section 111(d) as a “hybrid provision, intended to combine primary state responsibility for plan development and enforcement (as in section 110) with the technology-based approach (making allowances for the costs of controlling existing sources) taken in section 111 generally.”<sup>48</sup>

The commenter (2390-NMOGA) continues that the EPA acknowledged that, “[g]iven the variety of circumstances that may be encountered in controlling existing as opposed to new sources, it makes sense to have the [s]tates develop plans based on technical information provided by EPA and make judgments, subject to EPA review, concerning the extent to which less stringent requirements are appropriate.”<sup>49</sup> Providing states with “greater latitude” reflects EPA’s view that “requiring maximum feasible control of designated pollutants may be unreasonable in some situations.”<sup>50</sup> While there may only be one standard of performance for new sources of designated pollutants under section 111(b), the nature of regulating existing sources in section 111(d) may result in “several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.”<sup>51</sup>

In other words, the commenter (2390-NMOGA) points out that both in real time interpretation of the statutory provisions and consistently (until now), EPA has taken the position that states are allowed flexibility in developing state plans under CAA section 111(d).<sup>52</sup> And EPA reaffirms its interpretation in the Proposed Rules that providing states with flexibility “is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion.” But in the same breath, EPA proposes to disavow this position for

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<sup>44</sup> 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975).

<sup>45</sup> Id. at 53,342.

<sup>46</sup> Id. at 53,343 (emphasis added).

<sup>47</sup> Id. (emphasis added).

<sup>48</sup> Id.

<sup>49</sup> Id. at 53,344.

<sup>50</sup> Id.

<sup>51</sup> Id.

<sup>52</sup> See e.g., 45 Fed. Reg. 26,294, 28,298 (Apr. 17, 1980) (“[T]he States have more flexibility in establishing plans for welfare-related pollutants than is provided for plans involving pollutants that may affect public health.”); 60 Fed. Reg. 65,387, 65,414 (Dec. 19, 1995) (“The guidelines will not apply directly to any [designated facility], but will be used as a guide by individual State air pollution control agencies in developing site-specific regulations for designated facilities]. States are allowed some flexibility in implementing the guidelines.”).

EG 0000c. As described by below, however, the commenter asserts that the EPA fails to provide a reasoned justification for departing from this longstanding interpretation.<sup>53</sup>

a. EPA's concern that some state regulatory regimes include the regulation of non-designated facilities does not justify its categorical preclusion of total program evaluations.

Commenter (2390-NMOGA) states that CAA section 111(d) does not preclude state plans from including non-designated facilities for the purpose of demonstrating equivalency. EPA states that "CAA section 111(d)(1) only provides that state plans may include standards of performance and certain other requirements for designated facilities." EPA does not cite to the statutory language or to any case law supporting its interpretation. The commenter recommends that the EPA allow state plans to include rules that apply to non-designated facilities for the limited purpose of demonstrating the state plan will achieve equivalent emission reductions as EG 0000c. The commenter believes that allowing state plans to include regulations that apply to non-designated facilities, for the limited purpose of demonstrating equivalency, is consistent with the "cooperative-federalism approach" adopted by Congress in CAA section 111(d) "that leaves the [s]tates discretion in determining how their [s]tate and industry can best meet quantitative emissions guidelines established by the EPA."<sup>54</sup>

And even if EPA's interpretation is reasonable, the commenter (2390-NMOGA) states that the fact that a state plan cannot rely on emission reductions from non-designated facilities does not justify EPA's wholesale bar on submitting total program evaluations. The commenter notes that the EPA acknowledges that states will only submit or identify the aspects of the state program being submitted for approval under the state plan and "and include a detailed explanation and analysis of how the relied upon state programs are at least as stringent as the requirements of the final EG." A state can simply elect to exclude state regulations related to non-designated facilities in its plan submittal. As explained above, the commenter asserts that Congress intended for states to have wide latitude in developing and submitting state plans.

According to the commenter (2390-NMOGA), without any support or technical justification, EPA assumes that states with regulations for non-designated facilities, such as New Mexico's pigging requirements, will need to rely on those regulations to satisfy their requirement under CAA section 111(d). The commenter suggests that the EPA's rationale puts the cart before the horse. The commenter contends that it is undeniable that the burden is on states to develop and submit a plan under CAA section 111(d) for EPA's review and approval. Section 111(d) of the CAA requires states to submit and adopt state plans in a SIP-like process, which requires state rulemaking action followed by review and approval of state plans by EPA.<sup>55</sup> If a state fails to submit a satisfactory plan, EPA has the authority to instead prescribe a plan for the state.<sup>56</sup>

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<sup>53</sup> *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) (The "requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it is changing position. An agency may not, for example, depart from a prior policy sub silentio or simply disregard rules that are still on the books.").

<sup>54</sup> *Am. Lung Ass'n*, 985 F.3d at 942.

<sup>55</sup> 42 U.S.C. § 7411(d)(1) (citing 42 U.S.C. § 7410).

<sup>56</sup> 42 U.S.C. § 7411(d)(2)(A).



The commenter (2390-NMOGA) agrees that non-designated facilities should not be considered part of state plans for purposes other than demonstrating equivalency. However, the commenter believes that EPA should not preemptively preclude the submission of total program evaluations based on an unsupported assumption that some states may need to rely on existing state regulations for non-designated facilities to demonstrate equivalency under a total program evaluation.

b. EPA's interpretation that CAA section 111(d) does not allow approval of state plan requirements for non-designated pollutants does not support its categorical bar on total program evaluations.

Commenter (2390-NMOGA) notes that the EPA states that CAA section 111(d) does not allow EPA to approve state plan requirements for different pollutants than the designated pollutants being regulated in the emission guidelines. The commenter adds that EPA does not provide any support in the statute or case law for its interpretation that states cannot rely on regulations that regulate the emission of VOCs or other pollutants, if the state can demonstrate that those regulations achieve equal reductions in methane as a co-benefit. The commenter believes that EPA's interpretation is contrary to its prior statements confirming that VOC reduction measures simultaneously achieve methane reductions as a co-benefit.

The commenter (2390-NMOGA) continues that the EPA has consistently acknowledged the 1:1 emission co-benefit of VOC regulations for methane reductions. In NSPS OOOOa, EPA stated: "for the oil and natural gas source category, the available controls for reducing methane emissions simultaneously control VOC emissions and vice versa. Accordingly, the available controls are the same for reducing methane and VOC from the individual oil and natural gas emission sources."<sup>57</sup> EPA confirmed that "both methane and VOC are simultaneously and equi-proportionally reduced when controlled."<sup>58</sup> EPA continued to acknowledge this relationship in the November 2021 Proposal, stating that for oil and natural gas sources "methane and VOC are reduced in equal proportions, relative to their respective baselines by the multipollutant control option (i.e., where control is 95 percent reduction, methane and VOC are both simultaneously reduced by 95 percent by the multipollutant control)." The commenter notes that EPA again affirms this position in the proposed rules.

The commenter (2390-NMOGA) contends that the EPA's repeated confirmation that methane and VOC regulations control each pollutant in equal proportion supports states being able to include VOC regulations in their state programs under EG OOOOc because the regulations will result in the same proportional amount of methane reductions. States should be allowed to utilize existing state regulations that achieve methane reductions as a co-benefit or use VOCs as the trigger from control to demonstrate that the regulations are equivalent to the presumptive standards. The final rule for NSPS OOOOa notes that establishing the same GHG and VOC standards for equipment across the industry would "promote consistency by providing the same regulatory regime for this equipment throughout the oil and natural gas source category for both VOC and GHG, thereby facilitating implementation and enforcement."<sup>59</sup> Under the Proposed

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<sup>57</sup> 80 Fed. Reg. 56,593, 56,600 (Sept. 18, 2015).

<sup>58</sup> Id. at 56,617.

<sup>59</sup> 81 Fed. Reg. 35,824, 35,841 (June 3, 2016).

Rules, states would be deprived of the benefit of facilitating implementation and enforcement of one uniform state program that simultaneously reduces VOC and methane emissions. EPA is prematurely, and without justification, precluding states from being able to make this demonstration.

c. EPA's proposal to require states to establish the same standards as EPA removes states' flexibility in establishing state plans and is inconsistent with the structure of CAA section 111(d).

According to the commenter (2390-NMOGA), EPA does not rationally justify its concerns about allowing states to rely on different standards, both non-numerical and numerical, in the state plan equivalency demonstrations. EPA's concern that allowing states to use a non-numerical standard different from EPA's to demonstrate equivalency "would likely be technically difficult because many of the presumptive standards in the EG OOOOc are work practice standards that do not quantify emissions" fails to support its decision to deprive states of the flexibility Congress granted them under the statute. The commenter believes that the EPA assumes—without support—that this equivalency evaluation would need to be qualitative rather than quantitative because "not all states have comprehensive source and source-specific emissions inventory data to base a stringency comparison on emissions reductions alone."

The commenter (2390-NMOGA) adds that the EPA's assumption that using a non-numerical standard different from EPA's will result in an "extremely complicated" qualitative comparison is premature and at odds with the statute. Some states, such as Colorado, have a comprehensive GHG emissions inventory. Other states may rely on the federal GHG reporting program.

The commenter (2390-NMOGA) argues that it is ultimately up to the states to demonstrate how their respective state requirements result in emission reductions equivalent to EG OOOOc. As explained above, the commenter states that Congress intended for states to have wide latitude in developing and submitting state plans that satisfy the requirements of CAA section 111(d). EPA's proposal denies states the flexibility provided to them under the Act and abdicates EPA's responsibility to review state plans by pre-supposing the data possessed by states and their ability to submit satisfactory equivalency demonstrations.

EPA also proposes that states are expected to establish the same form of numerical standards as EPA in state plan equivalency demonstrations. The commenter (2390-NMOGA) reports that California, Colorado, Connecticut, Delaware, Illinois, Maine, Maryland, Michigan, Minnesota, New Jersey, New Mexico, New York, North Carolina, Oregon, Rhode Island, Vermont, Washington, Wisconsin, Massachusetts, Pennsylvania, and the District of Columbia submitted a joint comment on the November 2021 Proposal requesting that EPA permit the use of different numerical standards "consistent with the structure of section 111(d), under which states have wide latitude in developing their plans provided that the required level of emission reduction is achieved."<sup>60</sup> The commenter adds that the EPA acknowledges the state commenters' request, but denies it on the grounds that the "state commenters did not clearly provide specific examples of where a state already has a different form of a numerical standard that would necessitate this flexibility." The commenter states that this reasoning unreasonably places the burden on states to

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<sup>60</sup> See Docket ID No. EPA-HQ-OAR-2021-0317-1267.

provide an equivalency demonstration in their comments on a proposed rule. According to the commenter, the appropriate forum for a state to provide such an example would be in their individual state equivalency demonstration—not a public comment jointly submitted by several states. EPA’s rationale again abdicates its responsibility to review state plans by presupposing a state’s ability to submit satisfactory equivalency demonstrations.

4. EPA’s concern that a total program evaluation would leave some designated facilities unregulated is contrary to EPA’s interpretation that CAA section 111(d) authorizes states to establish standards of performance that, “in the aggregate,” are equivalent with the presumptive standards.

The commenter (2390-NMOGA) provides that, in *American Lung Association*, the D.C. Circuit expressly rejected EPA’s categorical exclusion of averaging in state plans.<sup>61</sup> Specifically, the court rejected EPA’s rationale that “asymmetrical regulation ‘could have significant localized adverse consequences for public health and the environment.’”<sup>62</sup> The court held that the reasoning failed to support the EPA’s categorical rule—or even EPA’s ban on averaging in that specific instance—because “carbon dioxide emissions do not pose localized concerns at the site of emission.”<sup>63</sup>

Here, the commenter (2390-NMOGA) believes that the EPA does not even try to support its ban on averaging by relying on health-based considerations. Rather, EPA states that if it “were to permit total program equivalence where state programs do not align with the EG, then there could be situations where a state would be allowed to forgo regulating some designated facilities that the EPA has determined are reasonable to control.” The example EPA provides is Colorado’s 15 barrels of oil equivalent (boe)/day threshold for its non-emitting pneumatic controller requirement—a state-based RULOF provision that accounts for the cost of implementing the standard at low-producing facilities.

In essence, the commenter (2390-NMOGA) notes that the EPA justifies its decision to categorically preclude total program evaluations on the grounds that source-by-source equivalency demonstrations will result in greater emission reductions because states with more stringent regulations for some sources, like Colorado, will be required to revise any less stringent regulations to meet the EPA standard. The commenter asserts that this position cannot be squared with the interpretation of CAA section 111(d)—shared by the D.C. Circuit and EPA in all other historic actions—that the statute does not categorically bar averaging and authorize[s] states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards.” Inherent in the ability to demonstrate equivalency in the aggregate, is the fact that some state regulations will be less stringent than the standard established in the emission guidelines. The D.C. Circuit’s decision in *American Lung Association* instructs that for EPA to bar states from submitting plans that rely on averaging, EPA must have a source- and pollutant-specific rationale that is justified and supportable.

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<sup>61</sup> 985 F.3d at 957.

<sup>62</sup> Id. at 958.

<sup>63</sup> Id.

But under the rationale supplied by EPA in the Proposed Rules, the commenter (2390-NMOGA) states that the agency could never allow state plans to rely on averaging without wholly reversing its position because any future EG that allows state plans to demonstrate equivalency “in the aggregate” will necessarily result in a source or category of sources being subject to regulations less stringent than EPA determined to be reasonable. The commenter contends that adherence to its position in the proposed rules will result in EPA adopting a de-facto categorical ban on averaging emissions under state plans, contrary to the D.C. Circuit’s holding in *American Lung Association*.<sup>64</sup>

Response II-19-6: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

### ***19.2.2 Source-by-Source Evaluation***

Comment: Commenter (2286-CO APCD) expresses concern with EPA’s proposed criteria, through which a state may make a source-by-source, designated facility equivalency evaluation. The commenter notes that EPA states that a state program that does not regulate the same pollutant, i.e., VOC versus methane, would not be able to move on to step two, evaluating whether the state program achieves the same or greater emissions reductions as the designated facility presumptive standards.

First, the commenter (2286-CO APCD) notes that many of the presumptive standards in EPA’s proposal will reduce VOC and methane emissions to the same extent. For example, the requirement to reduce methane emissions from fugitive emissions components will require the same work practices as a requirement to reduce VOC or hydrocarbons from components, i.e., through an LDAR program. However, under EPA’s rubric, a state would not be able to demonstrate that their VOC reducing LDAR program achieves the same or greater emissions reductions because the state program specifies VOC rather than methane.

Second, the commenter (2286-CO APCD) adds that states with ozone nonattainment areas classified as moderate or greater must adopt provisions in their SIP based on recommendations in EPA’s Control Technique Guidelines (CTG) when the state has sources in that VOC source category. For the oil and gas sector, EPA published the Oil and Gas CTG in 2016, which required subject states to revise their SIP and submit such revisions to EPA by October 2018. EPA’s Oil and Gas CTG recommends VOC control strategies for many of the same operations and equipment included in EPA’s proposed EG. The commenter notes that these are VOC standards, not methane. Therefore, the commenter asserts that states that were required to adopt SIP provisions based on the recommendations in EPA’s Oil and Gas CTG now have VOC requirements in their SIP that, based on EPA’s proposed equivalency evaluation rubric, cannot be used for purposes of comparing the effectiveness of their state program to EPA’s proposed presumptive standards. Furthermore, the commenter suggests that states may not be able to revise their SIP provisions to align with EPA’s proposed presumptive methane standards because EPA’s CTGs are designed to achieve ozone precursor emissions reductions, not GHG emissions reductions. None of this is discussed in EPA’s proposal and the commenter requests clarification

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<sup>64</sup> *Am. Lung Ass’n*, 985 F.3d at 957.

from EPA on how to streamline the program evaluation as well as the associated SIP and CAA section 111(d) rules.

Lastly, the commenter (2286-CO APCD) reiterates its concern, as stated in the previous comments submitted on EPA's 2021 proposal<sup>65</sup>, that EPA provide flexibility for states to modify state CAA section 111(d) plans without needing to submit each plan to EPA for approval, as is required for an initial state CAA section 111(d) plan or in response to final revised guidelines published by EPA. The commenter will need flexibility to revise Colorado's rules in a timely manner in response to numerous state and federal directives, as well as technological innovation in the industry. At a minimum, the commenter recommends that EPA allow states to modify their state CAA section 111(d) plans without further EPA approval where the modifications do not result in less stringent regulatory programs or where the changes are minor recordkeeping and reporting program adjustments.

Response II-19-7: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

### ***19.2.3 Application of Stringency***

Comment: Commenters (2249-NACAA, 2343-NYU-School of Law) make recommendations on the applications of stringency. Specific comments provided are presented in the following paragraphs.

Commenter (2249-NACAA) recommends that EPA's rule explicitly state that its emission reduction requirements are a baseline for all agencies, but that state and local regulatory agencies can use their own approaches if their needs are more effectively met with different paths that are overall at least as stringent and health-protective.

The commenter (2249-NACAA) states that the CAA and its section 111 are built on a model of cooperation that requires EPA to work in partnership with states, cities, and counties, among others, and by affording states additional – and essential – flexibility to chart compliance pathways, which can include emission limitations that are at least as stringent as the federal guidelines.

The commenter (2249-NACAA) explains that oil and gas operations also emit other criteria pollutants such as sulfur dioxide and nitrogen oxides, as well as air toxics including benzene, formaldehyde, toluene, ethylbenzene, and xylene. Some clean air agencies may have needs that more urgently prioritize these pollutants (or others) or prioritize specifically vulnerable communities (such as environmental justice communities or those most vulnerable to economic impacts of the rule.) The commenter suggests that the EPA may also wish to offer consistent and transparent discretion to adapt to a variety of disadvantaged community needs and understand with greater precision the economic effects of its rule on specific communities dependent on production. Where an agency can demonstrate reductions using approaches that are driven by other pollutants or that offer locally prioritized benefits of sufficiently demonstrated value, the

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<sup>65</sup> See Colorado comments at EPA-HQ-OAR-2021-0317-0775.

commenter recommends that EPA work with state and local agencies to meet their goals through this program.

Programmatic requirements may be equivalent, but the commenter (2249-NACAA) notes that wording and specific standards may be different for states with existing programs, and EPA should accommodate these variations. Where programs are less stringent in individual aspects but as or more stringent and protective overall, they suggest that EPA accommodate those tailored approaches that meet that agency's needs. Regarding the application of exemptions to disadvantaged or vulnerable communities, the commenter acknowledges that the EPA intends to allow these considerations in their determination of stringency. The commenter requests that EPA be clear about those criteria and their application before a rule is finalized.

Commenter (2343-NYU-School of Law) expresses that considering stringency in each year allows for more accurate comparisons. The commenter believes that EPA's preferred approach (comparing full-implementation stringency) could undermine Congress's intent that the methane charge be suspended only when EPA has sufficiently regulated methane emissions. For example, the commenter notes that a future administration might promulgate a new methane regulation that is as stringent as the November 2021 proposed rule when each is fully implemented, yet the new regulation might take a decade or longer to ramp up to that stringency. The delay might be due to a glide path to stringency within the new rule,<sup>66</sup> or elongated deadlines for submission, approval, and compliance with state plans, or both. If the equivalency determination were to depend only on stringency when the respective rules are fully implemented, these rules would be "equivalent." However, under the slow-ramping rule, the commenter states that the total emissions reductions would be far less than the November 2021 proposed rule, so a suspension of the methane charge would be unjustified.

Response II-19-8: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

#### ***19.2.4 Quantitative Comparison***

Comment: Commenter (2343-NYU-School of Law) asserts that the equivalency determination should be quantitative to facilitate accurate comparison and to set a standard of best practice for appropriate review in future rulemakings. The commenter contends that qualitative comparisons for subsequent rulemakings may not be straightforward. To conduct a quantitative equivalency determination, the commenter recommends that EPA analyze the November 2021 proposed rule using the same assumptions and methodologies that EPA now uses for the December 2022 supplemental proposal. The commenter states that this would allow an apples-to-apples comparison of the emissions reductions from the two regulations.

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<sup>66</sup> See, e.g., Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28,606, 28,617–28,621 (May 5, 2005) (establishing decreasing caps on mercury emissions that achieved maximum stringency in 15 years); Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,662, 64,667 (Oct. 23, 2015) (establishing increasingly stringent performance rates that reach maximum stringency in 15 years); Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 Fed. Reg. 39,154, 39,157 tbl.1 (July 11, 2006) (achieving full stringency in nine years).

The commenter (2343-NYU-School of Law) states that a qualitative approach may be appropriate under the unique circumstances of this rulemaking because the differences between the final rule and the November 2021 proposed rule will likely be relatively minor and point in the direction of increased stringency. But, even though the similarities between the design of the November 2021 proposed rule and the December 2022 supplemental proposal make it possible for EPA to find the December 2022 supplemental proposal at least equivalent without a quantitative analysis, the commenter recommends that EPA conduct a quantitative equivalency determination to set a standard of best practice. The commenter reports, for example, that EPA could promulgate a new regulation in the future that is more stringent in some ways but less stringent in other ways than the November 2021 proposed rule. The commenter asserts that a quantitative approach would better indicate whether that new regulation is at least as stringent as the November 2021 proposed rule. The commenter believes that the EPA has an opportunity now to set a best practice for future rulemakings and that quantitative analysis is most appropriate for the equivalency determination.

Response II-19-9: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

## **19.3 Remaining Useful Life and Other Factors (RULOF)**

### ***19.3.1 EPA Lacks Legal Authority to Require RULOF Provisions***

Comment: Commenter (2202-TXOGA) expresses concern that the proposed provisions to state plan development as compared with the November 2021 proposal are far more than mere “adjustments.” Specifically, the commenter expresses concern that the EPA is now proposing to introduce into the state plan development process what they believe are unprecedented and far-reaching requirements that would radically alter, both in its scope and effect, that regulatory program. Further, as discussed in more detail below, from the publicly available documents in the docket, the commenter states that they are unable to identify the provisions of the CAA that EPA believes provide the legal basis for adopting many of these requirements.

The commenter (2202-TXOGA) contends that the November 2021 proposal said almost nothing about the “remaining useful life and other factors” elements of the state standard-setting process under CAA section 111(d). It did not yet even have occasion to coin the “RULOF” acronym.<sup>67</sup> Instead, the commenter notes that the November 2021 proposal focused almost entirely on the Agency’s proposal to “translate the degree of emission limitation achievable through application of the BSER (i.e., level of stringency) into presumptive standards of performance that [s]tates may use in the development of [s]tate plans for specific emission points.” As the preamble there explained, “[i]n this way, the presumptive standards included in the EG serve a similar purpose as a model rule,” insofar as they are “intended to assist [s]tates in developing their plan

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<sup>67</sup> This stands in contrast to its usage 165 times in its December 2022 debut.

submissions by providing the [s]tates with a starting point for their standards that are based on general industry parameters and assumptions.”<sup>68</sup>

As for what the December 2022 proposal coins as the “RULOF” element of the state standard development process, the commenter (2202-TXOGA) states that the Agency in its November 2021 Notice provided fairly straightforward description of how that process worked, explaining that, “[t]o the extent that a [s]tate determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA’s regulations under CAA section 111(d) permit [s]tates to consider such factors in applying a standard of performance.” For that reason, the commenter notes that EPA pointed out, the current “implementing regulations at 40 C.F.R. 60.24a(e)” operate to “allow [s]tates to consider remaining useful life and other factors to apply a less stringent standard of performance to a designated facility or class of facilities if one or more demonstrations are made.”

The commenter (2202-TXOGA) continues to state that the EPA went on to announce to that it intended to “provide further clarification on the general process and requirements for accounting for remaining useful life and other factors, including on the reasonableness aspect of the required demonstration,” but that it would be doing so “via a rulemaking to amend the implementing regulations in the near future.” At the same time, the proposal said it “recognize[d] that the oil and natural gas industry” was so “unique” that the “general approach to considering remaining useful life and other factors in the implementing regulations may not be an ideal fit.” After a brief discussion of the factors that EPA believed rendered the industry “unique,” and after noting that the Agency had in the November 2021 notice “deliberately included certain flexibilities (e.g., in cases of technical infeasibility) such that the EPA believes the presumptive standards should be achievable and cost-effective for a wide variety of facilities across the source category,” the preamble opined that it “would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities.” That said, the preamble nevertheless solicited comment “as to whether the Agency should include specific provisions regarding the consideration of remaining useful life and other factors in this EG that would supplement or supersede the general provisions in the implementing regulations.”

The commenter (2202-TXOGA) expresses concern that the “specific provisions” now proposed in the December 2022 supplemental proposal regarding “remaining useful life and other factors” would not so much “supplement or supersede” the approach that EPA has been taking since 1977, as it would fundamentally transform the state standard-setting process for existing sources almost beyond recognition. The commenter disagrees with EPA’s radical change in direction of embracing an entirely new view of CAA section 111(d) that seems unrelated to traditional norms

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<sup>68</sup> EPA went on to say in its November 2021 Notice that, where states might choose to “submit a plan that includes standards of performance that are more stringent than the requirements of the final EG,” such states had “authority to do so under CAA section 116,” and that EPA had the “authority to approve such plans and render them Federally enforceable if all applicable requirements are met.” See 86 Fed. Reg. 63,251 (citing *Union Electric Co. v. EPA*, 427 U.S. 246, (1976)). There is much that is wrong with this assertion on the Agency’s part, as the commenter notes they previously explained. See TXOGA January 2022 Comments at 30-31. TXOGA incorporates those same objections here.



of statutory interpretation. The commenter recommends that EPA reconsider its new direction and revert to the historic one.

As its starting point for explaining why it is now “proposing to supersede the current 40 CFR 60.24a(c) by providing requirements specific to EG OOOOc for the consideration of RULOF in state plans to set a less stringent standard for a particular source,” the commenter (2202-TXOGA) provides that the preamble says that, “[a]s currently written, the RULOF provision in subpart Ba does not provide clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source.” Without acknowledging the fact that parameters for establishing less stringent standards have been in the Agency’s rules for nearly five decades or that such fears have not been realized, the commenter notes that the proposal suggests now that the “references to reasonableness [in current subpart Ba] are potentially subject to widely differing interpretations and inconsistent application among states developing plans.” It goes on to explain that “[w]ithout a clear analytical framework for applying RULOF,” the “current provision may be used by states to set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA’s BSER determination and render it meaningless.”

Further, the commenter (2202-TXOGA) provides that the preamble notes that “CAA section 111(d) does not require states to consider RULOF but requires that the EPA’s regulations ‘permit’ states to do so.” “In other words,” it continues, the Agency must “provide states with the ability to account for RULOF” but, at the same time, states “may instead choose to establish a standard of performance that is the same as the presumptive level of stringency set forth in the EGs.” According to the proposal, the “optionality, rather than mandate, for states to account for RULOF supports the notion that this provision is not intended to undermine the presumptive level of stringency in an EG for the source category broadly.” The commenter expresses that they do not believe that this asserted optionality-versus-mandate structure does not actually support the “notion” the preamble is asserting. The commenter notes, more confounding, is what the preamble says next: “EPA is not aware of any CAA section 111(d) EGs under which an EPA approved state plan has previously considered RULOF to apply a standard of performance that deviates from the presumptive level of stringency.” EPA expresses its hope, therefore, that the “[c]larifying parameters” for RULOF that it is proposing in the December 2022 proposal “may better enable states to effectively use this provision in developing their states plans.” In this context, the commenter states that such a statement seems illogical. If EPA is not aware of any state having ever previously employed the existing RULOF provisions to apply a standard to an existing source that “deviate[d] from the presumptive level of stringency,” then the commenter states it simply does not follow that EPA would now have a concern that “the current provision may be used by states to set less stringent standards that could effectively undermine the overall presumptive level of stringency.” In any event, the commenter contends that CAA section 111(d) does not mandate, or even authorize, an “overall presumptive level of stringency” for a class or category of sources. Instead, they believe it authorizes states to establish standards for individual existing sources based on BSER for that source.

The commenter (2202-TXOGA) states that the “clear analytical framework for applying RULOF” that the December 2022 Supplemental Notice now proposes is composed of:

- (1) “threshold requirements for consideration of RULOF,”
- (2) “adding requirements for calculating a less stringent standard accounting for RULOF,” (
- 3) “adding requirements for consideration of communities most affected by and vulnerable to the health and environmental impacts from the designated facilities being addressed,” and
- (4) “adding requirements for the types of information and evidence the states must provide to support for the invocation for RULOF in a state plan.”<sup>141</sup>

While each of these presents its own concerns, the commenter (2202-TXOGA) provides that the proposal goes even further. After acknowledging that, in its November 2021 proposal, EPA had reversed its recent position and was now proposing to take the position that “states are authorized to include in their state plans, and the EPA is authorized to approve, requirements that are more stringent than the EG under the authority of CAA section 116, as interpreted by the Court in *Union Electric v. EPA*, 27 U.S. 246 (1976),”<sup>69</sup> EPA is “now proposing that under CAA section 111(d), consistent with the authority conferred by CAA section 116, states may consider RULOF to include more stringent standards of performance in their states plans.” The commenter expresses concern that EPA is now proposing to turn CAA section 111(d) on its head, transforming the state standard-setting process into something that Congress plainly never envisioned.

#### a. Statutory and Regulatory Background on RULOF.

The preamble acknowledges that, not all that long ago, the Agency had taken the position that, “as part of the 1977 CAA Amendments ‘Congress effectively ratified the EPA’s implementing regulations’ clear construct [in 40 C.F.R. 40 CFR 60.24(f)] that remaining useful life and other factors are only relevant in the context of setting less stringent standards.” The commenter (2202-TXOGA) contends that not only does the language of 40 CFR 60.24(f)(3) (“[o]ther factors ... that make application of a less stringent standard ... more reasonable.”) provide relevant insight into Congress’s intent at the time it amended CAA section 111(d) in 1977, but it also highlights just how far afield the proposal would take the CAA section 111(d) standard-setting process. The commenter recognizes that EPA may alter statutory interpretations under applicable precedents; to do so, however, requires a sufficient explanation of such changes and that they be supportable under the statutory language and canons of statutory construction.

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<sup>69</sup> In its November 2021 proposal, the commenter provides that the EPA had “acknowledge[d] that in the Affordable Clean Energy (ACE) rule,” promulgated in July 2019, the Agency “previously took the position that Union Electric does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements.” 86 Fed. Reg. at 63,251. But, said EPA, it “no longer takes this position.” Id. Rather, “[u]pon further evaluation,” the Agency said it now believed that “because of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by *Union Electric* requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise in compliance with all applicable requirements.” Id. at 63,251-252. As is discussed elsewhere in their comments, the commenter believes that EPA’s new view of *Union Electric* is misplaced.

As the preamble points out, the “1970 version of CAA section 111(d) made no reference to the consideration of RULOF in the context of standards for existing sources.” While this is true, the commenter (2202-TXOGA) contends that the preamble omits another significant point. Not only did CAA section 111(d), as originally enacted in 1970, contain no mention of states being allowed, in setting “standards,” to “take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies” – the so-called RULOF provision would be added by Congress in 1977 – the “standards” to which CAA section 111(d) referred in 1970 were not “standards of performance” (as that term is defined in CAA Section 111(a)(1)) but, rather, “emission standards.”<sup>70</sup> The commenter reports that Congress did not initially connect the setting of standards for existing sources under CAA section 111(d) to the process by which “standards of performance” are derived (i.e., pursuant to CAA section 111(a)(1)) through the Administrator’s determining the “best system of emission reduction” for the category of sources in question. That connection was first made by EPA itself, in 1975, when it promulgated implementing rules under CAA section 111(d).<sup>71</sup>

The commenter (2202-TXOGA) points out that the stated rationale at the time of adoption for taking this approach, which was not self-evident on the face of CAA section 111(d) as originally enacted, is instructive. After examining the legislative history of what would become CAA section 111(d), the Agency concluded that what Congress intended was that “control of such [i.e., “designated”] pollutants on some basis was necessary,” that, “given the relative lack of information on their health and welfare effects, a technology-based approach (similar to that for new sources) would be more feasible than one involving an attempt to set standards tied specifically to protection of health,” and finally, that “the technology-based approach (making allowances for the costs of controlling existing sources) was a reasonable means of attacking the

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<sup>70</sup> See CAA section 111(d)(1); 42 U.S.C. § 1857c-6(d)(1) (1970) (“The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 1857c-5 of this title [i.e., CAA § 110] under which each State shall submit to the Administrator a plan which . . . establishes emission standards for any existing source of air pollution . . .” (emphasis added)). The generic term “emission standard,” while used throughout the CAA as it was first enacted in 1970, was not specifically defined in the CAA until the CAA Amendments of 1977. See CAA section 302(k); 42 U.S.C. § 7602(k).

<sup>71</sup> Specifically, the commenter provides that the implementing rules first adopted by EPA in 1975 directed that EPA, in publishing guideline documents, was to include an “emission guideline that reflects the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities . . .” 40 Fed. Reg. at 53,346 (Nov. 17, 1975). Thus, the terminology employed by EPA here found its origin in the definition of “standard of performance” as that term was first defined in 1970. See CAA section 111(a)(1); 42 U.S.C. § 1857c-6 (“The term ‘standard of performance’ means a standard for emissions of air pollutants which reflects the degree of emission reduction which (considering the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.”). Notably, the definition of “standard of performance” would later be quite significantly amended by the CAA Amendments of 1977 to mean, as relevant here: “. . . (C) with respect to any air pollutant emitted from a particular source to which subsection (d) of this section applies, a standard which the State (or the Administrator under the conditions specified in subsection (d)(2) of this section) determines is applicable to that source and which reflects the degree of emission reduction achievable through the application of the best system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources.” CAA section 111(a)(1)(C); 42 U.S.C. § 7411(a)(1)(C) (1977). The definition of “standard of performance” would again be significantly amended by the CAA Amendments of 1990 – for reasons not relevant to the issues relevant here – with those changes mostly returning the definition to the wording first used by Congress in 1970, but retaining the expanded language of the parenthetical clause – i.e., “. . . (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements).

problem until more definitive information became known.”<sup>72</sup> In short, the commenter notes that the Agency believed that the congressional conferees had chosen to rewrite what had originally been section 114 “as part of section 111 largely because they intended the technology based approach of that section to extend (*making allowances for the costs of controlling existing sources*) to action under section 111(d).”<sup>73</sup>

Elsewhere in the preamble to the 1975 rules, taking note of the fact that “[m]any commentators” had “apparently confused the degree of control to be reflected in EPA’s EGs under section 111(d) with that to be required by corresponding standards of performance for new sources under section 111(b),” the Agency observed that, “[a]lthough the general principle (application of best adequately demonstrated control technology, considering costs) will be the same in both cases, the degrees of control represented by EPA’s emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing sources will ordinarily be greater than those for control of new sources.”<sup>74</sup> The commenter (2202-TXOGA) asserts, while not explicitly stated, what EPA was referencing here was the fundamental concept that deriving a standard of performance for a category of new sources, through the ascertainment of the “best system of emission reduction” that can be incorporated at the outset into the design of new sources, involves different considerations than deriving an otherwise equivalent standard of performance for existing sources because any such “best system” would invariably require a more costly retrofit of control technology and may not even be technically feasible.<sup>75</sup> It was this very difference that provided the basis for EPA’s having incorporated into the 1975 rule what was then referred to as the “variance” provision.

As before, the commenter (2202-TXOGA) observes that the preamble discussion from 1975 sheds light on what EPA then had in mind. In rejecting one commenter’s assertion that “neither the letter nor the intent of section 111 allows variances from plan requirements based on application of best adequately demonstrated control systems,” EPA observed that, “[a]lthough section 111(d) does not explicitly provide for variances,” it nevertheless does require consideration of the cost of applying standards to existing facilities.”<sup>76</sup> Moreover, EPA continued, “[s]uch a consideration is inherently different than for new sources, because controls cannot be included in the design of an existing facility and because physical limitations may

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<sup>72</sup> 40 Fed. Reg. at 53,342 (emphasis added). This approach was all the more reasonable, EPA added, given that, under CAA section 116, states retained any authority they might otherwise have, as a matter of state law, to “adopt more stringent standards if they believed additional control was desirable.” Id. Notably, while subsection (g) of 40 CFR 60.24 provided that “[n]othing in this subpart shall be construed to preclude any State or political subdivision thereof from adopting or enforcing . . . emission standards more stringent than emission guidelines specified in subpart C of this part or in applicable guideline documents,” nowhere in either the rules themselves or in the 1975 preamble discussion did EPA suggest that more stringent requirements, adopted under state law, would be approved (or could be approved) as part of a state’s CAA section 111(d) and thereby become federally enforceable. As is discussed elsewhere in these comments, EPA’s current understanding of the scope and effect of CAA section 116 appears to the commenter (2202-TXOGA) to be somewhat flawed.

<sup>73</sup> 40 Fed. Reg. at 53,342 (emphasis added).

<sup>74</sup> Id. at 53,341.

<sup>75</sup> Cf. *Portland Cement Ass’n v. EPA, v. Ruckelshaus*, 486 F.2d at 391, as discussed supra.

<sup>76</sup> 40 Fed. Reg. at 53,344 (emphasis added).

make installation of particular control systems impossible or unreasonably expensive in some cases.”<sup>77</sup>

Thus, from the outset, in considering the congressional intent underlying CAA section 111(d), the commenter (2202-TXOGA) believes that EPA understood that the establishment and application of technology-based standards for existing sources – which, by definition, are afforded no opportunity to design in any “best system of emission reduction”– involved inherently different considerations than those that apply to new sources. Indeed, the commenter states that the EPA went so far as to assert that CAA section 111(d) itself required that such different considerations be accounted for, even though, as the text of the subsection read upon its original enactment in 1970, it actually said nothing in this regard – i.e., subsection (d) made no mention of “costs” nor, as has been noted, did it then contain what became the so-called RULOF considerations.

#### b. The 2022 New Interpretation.

The new December 2022 supplemental proposal is that “under CAA section 111(d), consistent with the authority conferred by CAA section 116, states may consider RULOF to include more stringent standards of performance in their state plans.” The preamble acknowledges, and the commenter (2202-TXOGA) agrees, that this represents an abrupt and significant departure from a decades-long approach to implementing CAA section 111(d). The commenter notes that the EPA recognizes that, in conducting the recent rulemaking to establish the current RULOF provision found at 40 CFR 60.24a(e), which “governs instances where states seek to apply a less stringent standard of performance to a designated facility,” the Agency had received “comments contending that if states may consider factors that justify less stringent standards,” states must “also be permitted to consider factors that would justify greater stringency than required by an EG, such as more expeditious compliance obligations or the retirement of a source.”<sup>78</sup> “In response to these comments,” EPA further admits, it had explained then that the Agency “interpreted the statutory RULOF provision as intended to authorize only standards of performance that are less stringent than the presumptive level of stringency required by a particular EG.”

The commenter (2202-TXOGA) states EPA now says that it has reevaluated its prior interpretation – i.e., the one to which it adhered for decades and which it had reinforced only a few years ago – and is “now proposing,” for purposes of EG OOOOc at least, to “interpret that the statute authorizes the EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by an EG.” Surprisingly, the commenter notes that the preamble states that EPA has newly found ambiguity in the language of CAA section 111(d). Specifically, having reviewed the phrase “... take into consideration, among other factors, the remaining useful life,” EPA has now determined that, “[a]side from the explicit reference to remaining useful life,” CAA section 111(d) is “silent as to what the ‘other factors’ are that states may consider in applying a standard of performance.”

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<sup>77</sup> Id.

<sup>78</sup> 87 Fed. Reg. citing EPA’s Responses to Public Comments on the EPA’s Proposed Revisions to Emission Guideline Implementing Regulations at 56 (Docket ID No. EPA–HQ–OAR–2017–0355–26740) (July 8, 2019).

In particular, the commenter (2202-TXOGA) adds that the EPA finds, CAA section 111(d) is actually “silent as to whether the ‘standard of performance’ to be ‘appl[ied]’ to a ‘particular source’ must be a weaker or stronger standard.” Under the new reading of the statutory text, the “only inference that can be drawn from the statutory language is that RULOF may be used to apply a different standard.” Therefore, EPA says, it may “reasonably interpret this ambiguity both as to what the ‘other factors’ are that states may use to apply a standard of performance to a particular source,” and “how such consideration may affect the stringency of such standard.” And it does so notwithstanding its prior statements that Congress had ratified EPA’s previous interpretation that such factors are only relevant in so far as they may support relaxing a standard. EPA proposes that this new interpretation is “reasonable,” suggesting that “if Congress intended the RULOF provision to be used only to allow states to apply less stringent standards,” then Congress would have “clearly specified that its intent” or else “enumerated ‘other factors’ that are appropriate for relaxing the stringency of a standard.”

The commenter (2202-TXOGA) provides that EPA acknowledges that it recently “reasoned that because the variance provision under subpart B is similar to and predated Congress’s addition to CAA section 111(d) as part of the 1977 CAA Amendments,” “Congress [had] effectively ratified the EPA’s implementing regulations’ clear construct that remaining useful life and other factors are relevant only in the context of setting less stringent standards.”<sup>79</sup> But now, the preamble asserts that EPA has “closely reexamined the variance provision in subpart B and the RULOF provision under CAA section 111(d),” such that it can no longer find any indication that “these provisions support the proposition that Congress clearly ratified the aspect of the variance provision in subpart B allowing states to apply only less stringent standards under certain circumstances.”

EPA bases its new position on a number of things that the Agency says this more recent “close reexamination” has raised in its consciousness. Individually, none of the points EPA makes here has much, if any, force, and they shrivel in the light cast by the contemporary interpretation that EPA advanced when it first promulgated rules to implement CAA section 111(d) and, in the course of doing so, first undertook to examine the congressional intent underlying that statutory program. Collectively, the commenter (2202-TXOGA) asserts that EPA’s points do not support the radical reimagining of CAA section 111(d) that the Agency is now proposing.

For example, the commenter (2202-TXOGA) states that now that it has undertaken its “close reexamination,” EPA says that it has come to realize (again, for the first time), that there are “notable differences between the subpart B variance provision that indicate Congress did not intend to incorporate and ratify all aspects of the EPA’s approach regulatory when amending CAA Section 111(d) in 1977.” Specifically, EPA says, for those designated pollutants “found to cause or contribute to endangerment of public health,” 40 C.F.R. Part 60, Subpart B as it currently reads (and as it was initially promulgated), “allows states to apply a less stringent standard under certain circumstances,” unless “EPA provides otherwise in a specific EG for a particular designated facility or class of facilities.” But, EPA continues, “subpart B places no similar exception for states in authorizing them to seek a variance for a standard addressing a pollutant for which the EPA has made a welfare-based, but not [a] public health-based,

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<sup>79</sup> 87 Fed. Reg. quoting EPA’s Responses to Public Comments on the EPA’s Proposed Revisions to Emission Guideline Implementing Regulations at 57 (Docket ID No. EPA-HQ-OAR-2017-0355-26740 (July 8, 2019)).

endangerment finding under 111(b)(1)(A).” The preamble states that this is significant because the “statutory RULOF provision does not make a similar distinction between public health and welfare-based pollutants.” This is what the proposal cites as indicating one “cannot clearly ascertain whether the statutory RULOF provision” actually “ratified the variance provision under subpart B” at all, “given that certain key elements of the latter are not present in the former.” It goes on to conclude that “[t]here is nothing in CAA section 111(d) or the legislative history that suggests that Congress enacted the statutory RULOF provision by ratifying certain elements of the regulatory variance provision in subpart B but not others.”

According to the commenter (2202-TXOGA), this effort to change positions and thereby walk away from the view that Congress plainly had in mind the regulatory variance provision, first adopted by EPA in 1975, when it amended CAA section 111(d) in 1977 to include what EPA now terms the statutory RULOF provision, is hard to reconcile with the timing and the facts, particularly given that Congress is presumed to be aware of such things when enacting legislation against a regulatory backdrop such as this. They add that it amounts to an assertion that, unless it can be said that Congress adopted the regulatory program in its entirety (i.e., more or less provision-by-provision, word-for-word) in incorporating into the statute the pre-existing regulatory program, there is simply no way of knowing what Congress may have intended and no possibility of ascertaining just where Congress got the idea of the RULOF provision in the first place. As noted, the commenter asserts that assuming an ambiguity in such a case is not consistent with regulatory or case precedent.

If anything, the commenter (2202-TXOGA) believes that the particular example EPA cites to shows a distinction between the regulatory variance provision promulgated in 1975 and the statutory RULOF provision Congress adopted in 1977, arguably cuts against the claim that congressional intent here is unknowable. Under the CAA section 111(d) implementing rules first adopted in 1975, the commenter provides that the variance provision of paragraph (f) only allowed states to establish less stringent standards for sources emitting “health-related” designated pollutants because only those sources were subject to the EPA guideline standards in paragraph (c). Welfare related emitters were not subject to guideline standards, but to the standards developed by a state balancing various factors.<sup>80</sup> In 1977, Congress eliminated the distinction between regulation of health-related emissions and regulation of welfare related emissions. The 1977 amendment subjected all designated sources – not just health related emitters – to the guideline standards and allowed states to relax those standards based on “remaining useful life” considerations like those listed in subparagraph (f) of the 1975 rule.

Next, the commenter (2202-TXOGA) states that the EPA revisits the legislative history of CAA section 111(d) but does so against the backdrop of the last rulemaking that considered the legislative history, i.e., its July 2019 Subpart Ba rulemaking. There, EPA had “asserted that the legislative history of the 1977 CAA Amendments supported its [then] interpretation” that “states may only consider RULOF to apply a less stringent standard.” EPA had taken note of the following statement from the House conference report adopting the amendment to add the statutory RULOF provision: “The section also makes clear that standards adopted for existing sources under section 111(d) of the Act are to be based on available means of emission control (not necessarily technological) and must, unless the state decides to be more stringent, take into

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<sup>80</sup> 40 CFR 60.24(d).

account the remaining useful life of the existing sources.”<sup>81</sup> EPA acknowledges that, from this, the Agency had previously reasoned that the “caveat that states have the choice to not invoke the RULOF provision and instead ‘be more stringent’ suggests that considering RULOF is only intended to allow a state to make a standard less stringent.”

But now, the commenter (2202-TXOGA) notes that the EPA says, it “finds that its prior reliance on this legislative history was flawed.” Yes, EPA concedes, the cited statement’s reference to “remaining useful life” speaks to a “factor that inherently suggests a less stringent standard.” At the same time, however, EPA goes on to allege, this bit of legislative history is “completely silent as to the ‘other factors’ the statute references.” Thus, as EPA would now have it, “there is no indication that Congress intended to limit the ‘other factors’ that states may apply in developing their plans only to permit less stringent, and not also more stringent standards.” If anything, EPA adds, the “cited statement explicitly acknowledges that states may choose to ‘be more stringent’, which,” as the Agency now construes it, “supports the EPA’s interpretation of the statute to permit states to consider other factors to set standards more stringent than the degree of emission limitation achievable through application of the BSER.”

The commenter (2202-TXOGA) disagrees and finds there is much that is wrong here. First, the commenter finds strained the analysis involved with EPA’s having first decided, upon reconsideration, that the RULOF provision’s reference to “other factors” is ambiguous, and then its construing the fact of there being no overt discussion of “other factors” in the legislative history as confirming that point.<sup>82</sup> It cannot reasonably be disputed that Congress had in view EPA’s 1975 implementing rules when it amended CAA section 111(d) in 1977.

The commenter (2202-TXOGA) asserts that all of the changes which Congress made to the provision at that time speak to this reality – i.e., the change in the wording of CAA section 111(d)(1)(A) and (1)(B) from “emission standards” to “standards of performance,” which was based on EPA’s own decision to base the development of EGs on a standard that reflected the “best system of emission reduction” (see 40 CFR 60.22(b)(5)); the inclusion of the final sentence

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<sup>81</sup> 87 Fed. Reg. at 74,826 quoting H.R. Conf. Rep. No. 94-1742, (Sep. 30, 1976), 1977 Legis. Hist. at 88. The House conference report’s parenthetical reference here to “available means of emission control (not necessarily technological)” is significant, as it indicates that the conferees clearly had in mind here the extensive changes that the 1977 CAA Amendments would also be making to the definition of “standard of performance” in CAA section 111(a)(1), as was noted above. The point is, the 1977 CAA Amendments would revise the definition of “standard of performance,” as applicable to new sources under CAA section 111(b) but not to existing source under CAA section 111(d), to require, among other things, that a “standard of performance . . . reflect the degree of emission limitation and the percentage reduction achievable through the application of the best technological system of continuous emission reduction . . . .” See CAA section 111(a)(1); 42 U.S.C. § 7411(a)(1) (1977). As noted previously, changes made to the definition of “standard of performance” by the CAA Amendments of 1990 would largely strip away the extensive textual changes wrought by the 1977 CAA Amendments. But what this shows is that, in 1977, the House conferees considering the changes then being proposed to CAA § 111(d) must have also been aware that the definition of “standard of performance” would be changed to expand the parenthetical clause “. . . (taking into account the cost of achieving such reduction) . . . .” to read “. . . (taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements) . . . .” The significance of this is discussed *infra*.

<sup>82</sup> This is a questionable way to interpret a statute in any event. *Cf. Railway Labor Exec. Ass’n v. National Mediation Bd.*, 29 F.3d 655, 671 (D.C. Cir. 1994) (“Were courts to presume a delegation of power absent an express withholding of such power, agencies would enjoy virtually limitless hegemony, a result plainly out of keeping with Chevron and quite likely with the Constitution as well.”)



in CAA section 111(d)(1), setting forth the RULOF provision, which was based on EPA's having adopted as part of its 1975 implementing rules a "variance" procedure, under which states could provide (but were not obligated to provide) for the "application of less stringent emission standards" (see 40 CFR 60.24(f)); and the last sentence of CAA section 111(d)(2), providing that, when EPA itself is "promulgating a standard of performance" in the case of a state's default, EPA "shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies," which was derived from the provision in the 1975 rules whereby "upon application by the owner or operator of a designated facility to which regulations proposed and promulgated under this section will apply," EPA was authorized to "provide for the application of less stringent emission standards . . . than those otherwise required by this section in accordance with the criteria specified" in the variance provisions of § 60.24(f)" (see 40 CFR 60.27(e)(2)).

In other words, the commenter (2202-TXOGA) states that *every* change that Congress made to CAA section 111(d) in 1977 can be traced directly back to specific provisions within the implementing rules that EPA had promulgated just two years earlier.

The commenter (2202-TXOGA) points out that the phrase "other factors" is itself derived from the variance provision in the 1975 implementing rules, which warrants being set out in its entirety here:

(f) On a case-by-case basis for particular designated facilities, or classes of facilities, States may provide for the application of less stringent emission standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the [s]tate demonstrates with respect to each such facility (or class of facility):

(1) Unreasonable cost of control resulting from plant age, location, or basic process design;

(2) Physical impossibility of installing necessary control equipment; or

(3) *Other factors* specific to the facility or class of facility that makes application of a *less stringent standard* or final compliance time significantly more reasonable.

40 CFR 60.24(f)(1)-(3) (1975) (emphases added).

Considering this, the commenter (2202-TXOGA) disagrees with EPA's contention that there is "no indication that Congress intended to limit the 'other factors' that states may apply in developing their plans only to permit less stringent, and not also more stringent standards". The commenter questions that if the reference to "among other factors" in CAA section 111(d) was not originally a reference back to EPA's own invocation of the term in its 1975 implementing rules, just where did the language come from.

According to the commenter (2202-TXOGA), equally strained is the assertion that this new interpretation is supported by the reference in the House conference report that "standards

adopted for existing source under section 111(d) . . . must . . . take into account the remaining useful life” of a given existing source “unless the state decides to be more stringent.” Far from being an “explicit[] acknowledge[ment],” as EPA would now have it, that “states may choose to ‘be more stringent’ when accounting for RULOF in applying a standard of performance to an existing facility, the reference is to the fact that, as CAA section 116 makes clear, a state is not precluded from setting a more stringent standard, as a matter of state law, should it so choose. The commenter asserts that the statement has nothing to do with RULOF. Here again, the commenter believes that the House conference report was almost certainly taking its cue from the provisions of the 1975 implementing rules, which in 1975 expressly provided that “[n]othing in his subpart shall be construed to preclude any [s]tate or political subdivision thereof from adopting or enforcing . . . emission standards more stringent than emission guidelines specified in subpart C of this part or in applicable emission guidelines.”<sup>83</sup>

c. Proposal’s New View of “Other Factors” and the “Consideration of Impacted Communities.”

Having divorced CAA section 111(d)’s use of the term “other factors” from its original statutory context, and having disavowed its own historical understanding of the term as set forth in its own implementing rules, the commenter (2202-TXOGA) believes that the proposed rule’s rationale lands at the place where it is prepared to argue that, because “CAA section 111(d) does not specify what are the “other factors” that the EPA’s regulations should permit a state to consider in applying a standard of performance,” the Agency is thereby afforded open-ended discretion to “identify the appropriate factors and conditions under which the circumstances may be reasonably invoked in establishing a standard less stringent than the EG.” Moreover, it contends, since “CAA section 111(d)(2)’s requirement that the EPA determine whether a state plan is ‘satisfactory’ applies to such plan’s consideration of RULOF in applying a standard of performance to a particular facility,” the Agency “must determine whether a plan’s consideration of RULOF is consistent with section 111(d)’s overall health and welfare objectives.”

The commenter (2202-TXOGA) asserts that the December 2022 proposal advances a significantly new view of what the consideration of “other factors” may entail. As the December 2022 proposal goes on to explain, “[w]hile the consideration of RULOF can be warranted to apply a less stringent standard of performance to a particular facility,” such standards “have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to impacts from the designated facilities being addressed by the state plan.” As described, “[t]hose communities could be put in the position of bearing the brunt of the greater health and environmental impacts resulting from that source implementing less stringent emission controls than would otherwise have been required pursuant to the EG.” Finding that a

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<sup>83</sup> 40 CFR 60.24(g); 40 Fed. Reg. at 53,347. As originally proposed, the implementing rule had provided that states “shall provide for a review of such facility for the purpose of applying less stringent emission standards.” See 39 Fed. Reg. at 36,104 (Oct. 7, 1974). In the final rule, EPA explained that “[s]everal commentators urged that proposed 40 CFR 60.23(e) [now 40 CFR 60.24(f)] be amended to indicate that States are not required to consider applications for variances if they do not feel it appropriate to do so.” 40 Fed. Reg. at 53,344 (emphasis added). EPA agreed with these commenters’ concerns and added that, “[i]n addition, there is some question whether the mandatory review provision as proposed would be consistent with section 116 of the Act, which makes clear that States are free to adopt and enforce standards more stringent than Federal standards.” Id. (emphasis added). “Accordingly,” EPA explained, the “proposed wording has been amended to permit, but not require, State review of facilities for the purpose of applying less stringent standards.” Id.

“lack of consideration to such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally,” EPA proposes as a requirement in EG OOOOc that states “consider such impacts when applying the RULOF provision to establish” a less stringent standards.

That is to say, the commenter (2202-TXOGA) states that the December 2022 proposal is “to require that, to the extent a designated facility would qualify for a less stringent through consideration of RULOF,” the state, “in calculating such standard,” must “consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions.” Further, EPA says, in describing this proposal, “state plan submissions seeking to invoke RULOF for a source must identify where and how a less stringent standard impacts these communities.” “In evaluating a RULOF option for a facility,” the Agency continues, “states should describe the health and environmental impacts anticipated from the application of RULOF for such communities,” along with “any feedback the state received during meaningful engagement regarding its draft state plan submission,” including on “any standards of performance that consider RULOF.” Finally, “to the extent that there is a range of options for reasonably controlling a source based on RULOF,” the December 2022 proposal specifies that, in “determining the appropriate standard of performance,” states “should consider the health and environmental benefits to the communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions,” and also “provide in the state plan submission a summary of the results that depicts the impacts to those communities.” According to EPA, this “requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF” is “consistent with the definition of ‘standard of performance’ in CAA section 111(a)(1).” As EPA now sees it, “[t]his definition requires the EPA to take into account health and environmental impacts in determining the BSER.” As a consequence, EPA concludes, “state plans must consider health and environmental impacts in determining a source specific BSER informing a RULOF standard,” just as “EPA is statutorily required to take into account these factors in making its BSER determination.”

The commenter (2202-TXOGA) notes that this is a new interpretation of the statute. As the commenter explains below, BSER is a technology-based standard, meaning that EPA is not statutorily required to consider “health and environmental impacts” in determining the BSER for new sources. According to the commenter, Congress did this on purpose because it was establishing minimum technology standards, without regard to air quality classification (attainment/nonattainment) or other factors. To the contrary, CAA section 111(a)(1) sets forth in unambiguous terms how EPA is to go about ascertaining BSER, and accounting for “health and environmental impacts,” as the Agency now contends, while important in other statutory contexts, is not part of that equation here. The commenter agrees because of the purposes of the NSPS program. Thus, it is simply not required for EPA to take these non-BSER factors into account, and because EPA is not required to do so, the commenter asserts that it cannot impose such a requirement on states in establishing their BSER utilizing RULOF.

Returning to first principles here, the commenter (2202-TXOGA) provides that the term standard of performance is defined in CAA section 111(a) as the “best system” of “emission reduction”

that EPA has determined is “adequately demonstrated.” In establishing BSER, the statute provides that EPA must “tak[e] into account” three, and only three, factors related to the system of emission reduction: “the cost of achieving such reduction,” “any non-air quality health and environmental impact,” and “energy requirements.”<sup>84</sup> Under CAA section 111(d), in establishing guidelines for performance standards under state implementation plans, EPA must identify BSER performance standards for classes and types of existing sources, considering the three control system factors identified in CAA section 111(a). States may establish standards less stringent than the presumptive performance standards in EPA guidelines based on consideration of an additional express factor: “remaining useful life.” Finally, EPA must promulgate an existing source performance standard if a state plan is deficient. In establishing that standard, EPA must “take into consideration . . . remaining useful life.” This “useful life” factor (which is unique to existing sources) must be considered “among [the] other factors” relevant to determining BSER. As was noted, in the proposal, EPA views the reference to “other factors” in CAA section 111(d) “as providing discretion for the EPA to identify . . . [additional] appropriate factors” that will govern a state’s establishment of CAA section 111(d) performance standards. EPA premises this conclusion on the assertion that “the statute is silent as to what the ‘other factors’ are that states may consider in applying a standard of performance.” Under this view of the reference to “other factors” in CAA section 111(d), EPA proposes to expand the factors governing standard setting to include consideration of an air quality health or environmental effects of the emissions from existing source, and to use that factor to preclude less stringent standards otherwise justified by application of the “remaining useful life” factor. As has already been noted, the reference to “other factors,” according to EPA, also allows the Agency to authorize states to create new decisional factors that can be used to “set” federally enforceable standards that are “more stringent than the degree of emission limitation achievable through application of the BSER.”<sup>85</sup>

The commenter (2202-TXOGA) contends that it is not accurate to assert that CAA section 111 is “silent” regarding the “other factors” referenced in section 111(d). As noted above, EPA had in the original variance provision in its 1975 implementing rules made explicit reference to “other factors,” while at the same time using language that limited those to factors that “make application of less stringent standard . . . significantly more reasonable,” and Congress certainly had EPA’s rules in view when it amended CAA section 111(d). Further, the commenter adds that

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<sup>84</sup> As has been noted, while the definition of “standard of performance” in CAA section 111(a)(1), as originally enacted in 1970, identified only one such factor – i.e., “the cost of achieving such reduction” – the CAA Amendments of 1977 expanded the statutory listing to the aforementioned three: i.e., “the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements.” Furthermore, as has also been explained, the changes made to the definition of “standard of performance” in the 1977 CAA Amendments were also in view of the House conferees considering the changes being made in 1977 to CAA section 111(d).

<sup>85</sup> 87 Fed. Reg. at 74,826. EPA’s selection of BSER in CAA section 111(d) guidance must be consistent with the CAA section 111 decisional criteria, and the guidance will be set aside by a court under CAA section 307(b) where EPA did not observe the statutory limits on BSER. Under EPA’s interpretation of “other factors,” EPA could approve, and make federally enforceable in civil and criminal proceedings, state standards that are not consistent with the statutory limits on BSER standards. In other words, EPA could “federalize” state standards that EPA could not recommend in its CAA section 111(d) guidelines or promulgate for a state under CAA section 111(d)(2). The commenter note that they had previously explained why such an outcome is impermissible. See TXOGA January 2022 Comments at 28-31. It reiterates its position here.

the very definition of “standard of performance” in CAA section 111(a)(1) speaks meaningfully to this issue.

As set forth in CAA Section 111(a)(1), the commenter (2202-TXOGA) specifies that three statutory control system factors are limited, by their terms, to the “costs,” “non-air quality health and environmental effects,” and “energy requirements” of control systems. The commenter notes that nowhere are the “air quality” effects of emissions from a source mentioned. The “air quality” health and environmental effects of source emissions are not a relevant factor under CAA section 111, nor are any additional new factors that may be created by states to justify more stringent standards.

In sum, the commenter (2202-TXOGA) argues that the EPA should not interpret the CAA to delegate to EPA, and to the states, the authority to expand the factors relevant to establishing performance standards, allowing states to adopt, and EPA to approve, federally enforceable standards that are not based on BSER but upon other factors not listed in the statute. The concern is that this would create an open-ended delegation to create new decisional factors, and EPA recognizes that it “cannot anticipate each and every [new] factor” that a state might choose to use in setting more stringent federally enforceable standards. The commenter states that the reference to “other factors” in CAA section 111(d) is not, however, an open-ended delegation for EPA to impose on the states additional “air quality” based decisional factors, or to authorize the states to add decisional factors in setting CAA section 111(d) standards that EPA may approve as federally enforceable standards. The “other factors” are those that Congress listed in CAA section 111(a)(1).

The commenter (2202-TXOGA) expresses serious concerns with EPA’s proposed interpretation. Congress routinely delegates rulemaking powers to federal agencies under the direction of specific statutes. The commenter asserts that rulemaking delegations do not violate the Constitution’s requirement that “[a]ll legislative powers here in granted shall be vested in a Congress,” as long as Congress defines the nature and scope of the delegation.<sup>86</sup> CAA section 111 provides specific statutory criteria for establishing BSER performance standards in CAA section 111(a) and (d). Specifically, the commenter provides that a standard must be “achievable” with “demonstrated” systems selected after “taking into account” the three control system factors. These criteria constrain EPA’s exercise of discretion in promulgating regulations under both CAA section 111(b) and CAA section 111(d). Yet, under EPA’s new interpretation, the commenter notes that the EPA is claiming the authority to impose on states new “air quality” decisional criteria focused on facility emissions, and to authorize states to develop decisional criteria that may be used to establish federally enforceable standards more stringent than BSER. The commenter (2202-TXOGA) asserts that EPA lacks the discretion it claims, as illustrated by *Union Electric Co. v. EPA*,<sup>87</sup> where the Supreme Court rejected petitioners’ claim that EPA must consider economic or technical infeasibility factors in approving state implementation plans under CAA section 110 of the Act. Citing the eight factors set out in CAA section 110, governing states implementation plans, none of which included consideration of economic and

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<sup>86</sup> U.S. Const., art. I, § 1; see *Touby v. United States*, 500 U.S. 160, 165 (1991) (“So long as Congress ‘lay[s] down by legislative act an intelligible principle to which the person or body authorized to [act] is directed to conform, such legislative action is not a forbidden delegation of legislative power.’”).

<sup>87</sup> 427 U.S. 246 (1976).

technical feasibility, the Court held that EPA had no authority to depart from the statute's terms and consider additional factors.<sup>88</sup>

The commenter (2202-TXOGA) notes that “all legislative powers” in the federal government are vested in Congress. They point out that Congress’ authority to make federally enforceable law therefore may not be delegated unless the delegation is circumscribed by congressionally stated criteria. The commenter contends that an interpretation of CAA section 111(d) that Congress authorized the Agency to expand the decisional factors governing performance standard setting without any statutory guidance and that Congress also allowed EPA to approve more stringent state standards that are based on consideration of factors found nowhere in the statute, would violate separation of powers and the nondelegation doctrine. According to the commenter, allowing an agency to create civil and criminal liability for creation of standards untethered to congressional guidance would raise serious due process problems. Cf. *Touby*, 500 U.S. at 165-66 (suggesting the possibility that “something more than an ‘intelligible principle’” may be required where (as in CAA Section 112) “Congress authorizes another Branch to promulgate regulations that contemplate criminal sanctions.”).

Finally, the commenter (2202-TXOGA) states that it seems worth noting that EPA’s decision to propose this new view of “other factors” in the specific context of proposed EG OOOG is anomalous in and of itself. Early on, EPA had said that, in order to address what it termed the absence of “clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source,” the Agency was “intend[ing] to propose clarifying revisions to this provision [i.e., 40 CFR 60.24a(e)] under the implementing regulations in an upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d).” The commenter would have expected EPA to wait to introduce this proposed new view of “other factors” then, in that broader rulemaking.

Response II-19-10: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### 19.3.1.1 Proposed Requirements for Setting Emissions Standards Based on RULOF

Comment: Commenter (2428-API) disagrees with components of EPA’s proposed requirements when a state considers setting emission standards. EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must “determine and include, as part of the plan submission, a source specific BSER for the designated facility” . EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. The commenter (2428-API) believes that this is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER

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<sup>88</sup> Id. at 265.

analysis under CAA section 111(d) rather than setting standards of performance based on an EPA BSER determination.

The commenter (2428-API) agrees with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. The commenter acknowledges that when a state considers RULOF, EPA's own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that “the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology” and that “a state must also consider all these factors in applying RULOF for that source.” The commenter (2428-API) agrees that the statute requires the first three criteria to be considered in determining BSER. The commenter agrees that application of these criteria is consistent with the principle that state CAA section 111(d) plans must meet the statutory standard setting criteria. However, the commenter does not agree that the statute specifies or requires that BSER also must be based on an assessment of “the amount of reductions” or “advancement of technology.” The commenter asserts that a state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis “must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above.” The commenter (2428-API) disagrees. The commenter states that the state clearly must determine BSER based on the express statutory criteria but argues that the law does not require a state BSER analysis to “identify all control technologies available for the source,” “use the same metrics,” or provide an evaluation “in the same manner” as EPA used in developing its BSER analysis. The commenter asserts that nothing in the law requires a state to follow EPA's preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA's.

Response II-19-11: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2298-Pioneer) urges EPA to develop a final rule that reflects Congress intention and provide states with latitude in the standards they establish for their existing sources. The commenter notes that CAA section 111(d) provides that it is the states who in their plans establish standards of performance for existing sources, subject to EPA review and approval. And subsection (d) explicitly requires EPA to allow states to "take into consideration, among

other factors, the remaining useful life of the existing source" for which the state plans establish standards of performance.<sup>89</sup> The commenter contends that the existing-source program is, therefore, a "cooperative federalism" program under which Congress intended that states would have considerable flexibility in establishing standards of performance for existing sources.

The commenter (2298-Pioneer) requests that EPA provide adequate flexibility to states in assessing the applicability of RULOF and developing their plans that establish standards of performance for existing sources. The commenter believes that this is in keeping with the text and structure of CAA section 111, as well as with the common-sense observation that it is easier for regulated companies to plan and execute design and operational changes for new and modified sources than for existing sources.

The commenter (2298-Pioneer) expresses concern that EPA seems to interpret the CAA to delegate to EPA, and to the states, the authority to expand the factors relevant to establishing performance standards, allowing states to adopt, and EPA to approve, *more stringent* federally enforceable standards that are not based on BSER but improperly upon "air quality" health and environmental effects of a source's emissions, or upon other factors not mentioned in CAA section 111. In proposing to give states an open-ended delegation to create new decisional factors, EPA concedes that it "cannot anticipate each and every [new] factor" that a state might choose to use in setting more stringent federally enforceable standards. The commenter states, however, that the reference to "other factors" in CAA section 111(d) is not an open-ended delegation/or EPA to impose on the states additional "air quality" based decisional factors, nor an authorization/or the states to add decisional factors in setting CAA section 111(d) standards that EPA may approve as federally enforceable standards. The commenter asserts that the "other factors" are those that Congress listed in CAA section 111(a)(1). No more, no less.

Response II-19-12: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2399-GPA) asserts that the December 2022 supplemental proposed rule's various proposed changes to how states will establish emission limitations for existing sources raises numerous legal and factual concerns. The commenter urges EPA to rethink this approach. To begin, EPA is proposing through the December 2022 supplemental proposal to finalize significant changes to Subpart Ba, governing how States establish existing source performance standards, while simultaneously proposing similar changes through a separate rulemaking.<sup>90</sup> The commenter expresses concern with not only differences between the two proposals, but the December 2022 supplemental proposal suggests EPA has already determined what revisions it will make to Subpart Ba regardless of the public notice and comment process required under the Administrative Procedure Act (APA). The commenter recommends that EPA

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<sup>89</sup> CAA Section 111(d)(4).

<sup>90</sup> See 87 Fed. Reg. 79,176 (Dec. 23, 2022) ("Proposed Subpart Ba Rule").



await its Ba rulemaking and follow those procedures, rather than create separate procedures in this rule.

More fundamentally, the commenter (2399-GPA) urges EPA to rethink its approach, because its proposal is contrary to Congress' clear direction in the plain language of CAA section 111(d) to grant the states substantial discretion to develop their governing plans for existing sources. Yet, the commenter states that the substance of the EPA's proposal would impose an unprecedented level of federal micro-management over how states would establish emission limitations for existing sources and strip away the discretion that Congress gave to the states under CAA section 111(d). In support of its proposal, EPA has selected out phrases from the statute to create its "satisfactory plan" and "standards of performance" theories for interpreting the Act. But EPA's reading is contradicted by CAA section 111's plain language and structure, as well as case law interpreting that statute.

Even if these proposed revisions were lawful – and the commenter (2399-GPA) believes that they clearly are not – the rationale for imposing them lacks a record basis, includes impermissibly vague requirements, and will have the effect of making states' consideration of facilities' remaining useful life and other factors so onerous as to be practically impossible, despite Congress expressly authorizing states to consider those matters.

Response II-19-13: The EPA disagrees with the commenter's description that suggested EPA proposed to amend subpart Ba through the December 2022 Supplemental Proposal for the NSPS and EG for the oil and natural gas industry (OOOOb and OOOOc). The EPA clarifies that the December 2022 Supplemental Proposal did not propose to amend 40 CFR Part 60 Subpart Ba, but rather proposed that EG OOOOc include certain regulatory provisions that were very similar to, if not the same as, provisions that EPA later proposed to include in subpart Ba. Via a different rulemaking process, the EPA separately proposed amendments to subpart Ba. See 87 FR 79176. The EPA agrees that there was overlap, and even some redundancy, when comparing EPA's proposed EG regulatory text in the December 2022 Supplemental Proposal and the proposal for amending subpart Ba. The EPA further acknowledges that finalizing the same provisions in two separate rules could have been confusing and unnecessarily redundant for both states and tribes but also owners and operators of designated facilities. The EPA explains this further within Section XIII.C of the final rule preamble for OOOOc. Since certain issues that the EPA had proposed within EG OOOOc are now addressed in the final revisions to subpart Ba, and subpart Ba applies to states developing plans under this EG (OOOOc), it would be redundant for EPA to also finalize the same provisions related to these issues within EG OOOOc. As such, EPA is not finalizing certain provisions as proposed in the context of this EG (OOOOc) and is instead deferring to subpart Ba on certain issues as explained in the preamble. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

### 19.3.1.2 EPA Authority to Approve State CAA Section 111(d) Programs That are More Stringent

Comment: Commenter (2428-API) notes that in the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state CAA section 111(d) programs that are more stringent than would be required by application of the BSER determined by EPA. That position is expanded in the December 2022 supplemental proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans". The commenter expresses concern that this position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures.

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source". Moreover, EPA now rejects the idea that the CAA section 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA section 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." The commenter (2428-API) asserts that EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, the commenter states that the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. According to the commenter, the term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life ... is a factor that inherently suggests a less stringent standard." In this context, the commenter suggests that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the commenter asserts that the term "other factors" must be construed in this manner.

Second, the commenter (2428-API) provides that the EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." At the same time, the commenter believes that the EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by EG OOOOc).

The commenter (2428-API) states that it is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at

74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. The commenter disagrees with EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

Response II-19-14: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### 19.3.1.3 EPA Does Not Have Authority to Prescribe State Plan RULOF Requirements

Comment: Commenter (2252-PAW) contends that EPA does not have authority to prescribe state compliance plan requirements. The commenter recommends that EPA allow states to continue to lead. The commenter notes that EPA states that "remaining useful life" is one "factor" that CAA section 111(d) explicitly requires that the EPA permit states to consider in applying a standard of performance." and that "the provision does not provide guidance or parameters on when and how a state may do so" and thus takes it upon itself to delineate what a state compliance plan should include. The commenter asserts that this is not an accurate interpretation of the CAA. The commenter contends that Congress explicitly delegated to states the authority to develop compliance programs for existing sources, while allowing them to consider of remaining useful life. The commenter submits that Congress intentionally left great discretion to states to deviate from the EPA's standards. The commenter asserts that states are the governmental entities with expertise in air quality compliance and enforcement and are thus best equipped to make judgement calls regarding requirements for sources under their jurisdiction.

Commenter (2326-AXPC) asserts that EPA must give the states meaningful discretion and flexibility in how they regulate existing sources in their state plans. The commenter contends that CAA section 111(d)(1) requires EPA to allow states to assign standards of performance to existing sources that are not one-size-fits-all, top-down requirements, and that take into consideration the circumstances of those sources.<sup>91</sup>

Regulations of the Administrator under this paragraph *shall* permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

The commenter (2326-AXPC) states that there are two obvious policy reasons why Congress provided different treatment for existing and new sources. The first is an economic reason:

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<sup>91</sup> (emphasis added).

retrofitting or altering operations at an existing source to comply with regulations is more burdensome, and in some cases impossible, as compared to designing a newly constructed source. The second is a question of policy and the legal framework of the CAA: Congress knows states are more aware of and better equipped to handle the circumstances of their existing-source fleet than EPA.

The commenter (2326-AXPC) contends that EPA's proposal is inconsistent with the design of the existing source program, and Congress' direction that it allow the states this role. Rather, the commenter asserts that EPA's proposal adds unnecessary burdens on states' ability to exercise the authority Congress directed EPA to allow them, without statutory justification.

EPA proposes to require a state to engage in additional public engagement and to step into the shoes of the EPA itself by conducting its own, source specific BSER analysis before it assigns a standard of performance to a particular existing source that is less stringent than what would result from a direct application of the presumptive requirements in EPA's EGs. The commenter (2326-AXPC) states that Congress did not authorize these additional requirements in CAA section 111(d). The commenter suggests that EPA's motives are in direct conflict with what Congress gave the states through their RULOF authority, and instead proposes a program so onerous for states that they will just accept EPA's requirements and avoid the considerable burden that would be required to exercise their express statutory RULOF authority.

Tellingly, the commenter (2326-AXPC) provides that the EPA requires no additional process for a state that wishes to assign a more stringent standard of performance to an existing source. The commenter asserts that EPA has not justified this different treatment – other than by observing that more stringent standards will lead to greater emissions reductions.

The commenter (2326-AXPC) states that CAA section 111 is not a maximum-achievable-reductions provision, unlike some other provisions of the CAA and other environmental statutes. It requires a careful threshold analysis by EPA as to what systems of emissions reductions are “adequately demonstrated” and what reductions are “achievable,” and it contains language directing EPA to allow states to vary from EPA's own presumptive standards where particular circumstances warrant. The commenter contends that the one-way ratchet created by EPA's split treatment of states confirms its inconsistency with Congress' statutory scheme.

Finally, the commenter (2326-AXPC) asserts that EPA also disregards the statutory scheme when, in what appears to be the first time ever, it proposes to require that states undergo their own version of a BSER analysis before assigning a less stringent standard to an existing source. The commenter states that BSER occurs only in one portion of CAA section 111, in the initial definition of “standard of performance” in CAA section 111(a)(1). In that provision, it is explicitly the EPA Administrator's role to determine BSER. According to the commenter, in constricting states from being able to fully exercise the authority Congress granted them in CAA section 111(d), EPA is blurring the lines, departing from its previously unbroken insistence that BSER is a matter for the EPA, and confusing two distinct roles which could not be clearer under the text and structure of the statute.

The commenter (2326-AXPC) contends that Congress' design for existing-source regulation is quite clear. EPA should determine what reductions existing sources as a categorical matter can be expected to achieve (considering whether and how existing sources differ in this regard from new ones). EPA directly regulates new sources. But *states* set standards of performance for their existing sources in their state plans, with the authority to "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." The commenter asserts that EPA's attempt would impose extra hurdles and blur clear statutory lines which is not in keeping with Congress' design. The commenter states that EPA has no authority to impose these requirements, and certainly does not have authority to reject a state plan as not being "satisfactory" for failure to comply with them.

Commenter (2443-NMOGA) contends that the RULOF revisions would require states to conduct multiple BSER analyses, and that EPA fails to justify their change in interpretation and application. The commenter outlines their concerns in the following paragraphs.

a. The proposed RULOF revisions would unreasonably require states to conduct multiple BSER analyses, with additional requirements, contrary to CAA section 111(d).

The commenter (2443-NMOGA) states that the CAA requires EPA to promulgate regulations implementing CAA section 111(d) that permit a state submitting a state plan "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."<sup>92</sup> If a state fails to submit a satisfactory state plan and EPA prescribes a plan for the state, EPA must similarly "take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies."<sup>93</sup>

The current RULOF provisions in the section 111(d) implementing regulations allow a state to consider the following factors: (1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make the application of a less stringent standard or final compliance time significantly more reasonable.<sup>94</sup> The commenter (2443-NMOGA) asserts that EPA is now proposing excessive revisions to the RULOF provisions that will require states to (1) meet specific threshold requirements for the consideration of RULOF; (2) calculate a less stringent standard accounting for RULOF; (3) consider communities most affected by and vulnerable to the health and environmental impacts from the designated facilities being addressed; and (4) provide certain information and evidence to support the invocation of RULOF in a state plan. The commenter objects to the procedural overlay and restrictive standard of evaluation proposed by EPA for states to submit and support RULOF demonstrations that will effectively turn the RULOF provisions in CAA section 111(d) into a dead letter.

The commenter (2443-NMOGA) asserts that EPA does not cite any authority or statutory text supporting its new, restrictive view of RULOF or demonstrate that "Congress meant to so hogtie

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<sup>92</sup> 42 U.S.C. § 7411(d)(1).

<sup>93</sup> 42 U.S.C. § 7411(d)(2).

<sup>94</sup> 40 CFR 60.24a(e).

the [s]tates” in developing plans under CAA section 111(d).<sup>95</sup> EPA claims that the current RUOF provisions could result in differing interpretations and inconsistent application and should therefore require clear parameters for states on how and when to apply a less stringent standard than the presumptive level of stringency in an EG for a particular source. But the commenter notes that EPA has acknowledged that the application of less stringent requirements is a case-by-case evaluation and should not be subject to overly prescriptive threshold requirements.<sup>96</sup> The commenter believes that Congress directed EPA to permit states to consider a source’s RUOF to acknowledge the basic fact that it is generally more difficult (and costly) for existing sources to retrofit pollution controls than it is for new sources to install them. As EPA explained in a prior rulemaking, “Congress intended the remaining useful life provision to provide a mechanism for states to avoid the imposition of unreasonable retrofit costs on existing sources with relatively short remaining useful lives, a scenario that could result in stranded assets.”<sup>97</sup>

The commenter (2443-NMOGA) states that the EPA has long recognized that states may apply less stringent requirements in its state plans “when economic factors or limitations make such application significantly more reasonable.”<sup>98</sup> In EPA’s initial regulations implementing CAA section 111(d)—before RUOF—EPA recognized that application of the specified standards in an emission guideline “may be unreasonable” when the cost of the upgrades and the emission reductions become disproportionate.”<sup>99</sup> To account for this, EPA promulgated regulations that “provide that [s]tates may establish less stringent emission standards on a case-by-case basis provided that sufficient justification is demonstrated in each case.”<sup>100</sup> In that rulemaking, commenters confused the degree of control to be reflected in EPA’s EGs under CAA section 111(d) with that to be required by corresponding standards of performance for new sources under CAA section 111(b).<sup>101</sup> EPA clarified that:

[a]lthough the general principle (application of best adequately demonstrated technology, considering costs) will be the same in both cases, the degrees of control represented by the Agency's emission guidelines will ordinarily be less stringent than those required by standards of performance for new sources because the costs of controlling existing facilities will ordinarily be greater than those for control of new sources.<sup>102</sup>

And the D.C. Circuit Court of Appeals has explained that the requirement that state standards under CAA section 111(d) must “‘reflect’ the emission guidelines does not mean that they must embody the methods EPA contemplated in identifying the best system; rather, the [s]tates have

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<sup>95</sup> *Am. Lung Ass’n*, 985 F.3d at 957.

<sup>96</sup> 39 Fed. Reg. 36,102, 36,102 (Oct. 7, 1974) (“States may establish less stringent emission standards on a case-by-case basis provided that sufficient justification is demonstrated in each case.”).

<sup>97</sup> 80 Fed. Reg. 64,622, 64,872 (Oct. 23, 2015).

<sup>98</sup> 45 Fed. Reg. 26,294, 28,298 (Apr. 17, 1980).

<sup>99</sup> 39 Fed. Reg. 36,102, 36,102 (Oct. 7, 1974).

<sup>100</sup> *Id.*

<sup>101</sup> 40 Fed. Reg. 53,340, 53,341 (Nov. 17, 1975).

<sup>102</sup> *Id.* at 53,341 (emphasis added).

flexibility in determining the specifics of the standards they issue so long as they accomplish the ‘degree of emission limitation’ the EPA calculated based on its ‘best system.’”<sup>103</sup>

The commenter (2443-NMOGA) asserts that EPA has faithfully and consistently implemented its RULOF regulations for over forty years. The commenter notes that EPA revised the RULOF revisions only a few years ago and made no mention at that time of a historical issue with a lack of clarity or clear direction for states under the regulations.<sup>104</sup> But the commenter states that EPA is now proposing that states submit “a source-specific BSER [analysis] for the designated facility” that must be in the same form as the EG OOOOc presumptive standard, in addition to the other demonstration requirements a state must provide for RULOF to be considered in a state plan, including a requirements to evaluate “all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG.” The commenter contends that EPA’s proposal is in stark contrast to its long-standing interpretation and application of RULOF and removes all the flexibility Congress intended to provide states in developing and submitting state plans by requiring states to provide a demonstration even more rigorous than what EPA did for the establishment of NSPS OOOOb. And given that EPA, with very limited exceptions, proposes the same requirements for existing sources that would be subject to EG OOOOc as it does for new sources that would be subject to NSPS OOOOb, it is clear to the commenter that EPA did not already take into account costs for existing sources.

The commenter (2443-NMOGA) suggests that had Congress intended for RULOF demonstrations to require a complete BSER analysis and independent evaluation of alternative technologies, it would have said so.<sup>105</sup> The commenter believes that this was not Congress’s intention and EPA has never interpreted the statute this way. The commenter contends that requiring states to conduct a more rigorous evaluation than what was required for determining BSER in the first place is contradictory to the structure of CAA section 111(d) as they apply to existing sources.

Further, the commenter (2443-NMOGA) expresses concern that many of EPA’s proposed requirements would completely prevent the use of RULOF in the oil and natural gas sector. For example, EPA proposes to require that state plans include a retirement date for the designated facility as an enforceable commitment and requires measures that provide for the implementation and enforcement of retirement. The commenter reports that this requirement is impracticable for the oil and natural gas sector because there are thousands of applicable sources (small in nature) within a state as opposed to a dozen or so large sources. The commenter notes that EPA has made no effort to tailor its RULOF provisions to the source category being regulated. EPA also proposes to limit states to submitting RULOF demonstrations for four categories of designated facilities: oil wells with associated gas designated facilities; storage vessels; pneumatic controllers; and pneumatic pumps. The commenter notes that EPA does not explain or provide

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<sup>103</sup> *Am. Lung Ass’n.*, 985 F.3d at 942–943.

<sup>104</sup> 84 Fed. Reg. 32,520, 32,524 (July 8, 2019) (“EPA’s role under CAA section 111(d) is narrow. Indeed, CAA section 111(d) tasks states with “establish[ing] standards of performance for any existing source” and “provid[ing] for the implementation and enforcement of such standards of performance.”).

<sup>105</sup> E.g., *W. Virginia v. Env’t Prot. Agency*, 213 L. Ed. 2d 896 (June 30, 2022) (“Agencies have only those powers given to them by Congress, and enabling legislation is generally not an open book to which the agency [may] add pages and change the plot line.” (internal quotations and citations omitted)).

any support for its determination that RULOF is only appropriate for, and should be limited, to these four categories of designated facilities.

The commenter (2443-NMOGA) contends that EPA is again prematurely presuming that states are incapable of submitting satisfactory state plans, yet EPA does not point to any prior examples of states submitting unsatisfactory state plans due to the alleged ambiguity of the current RULOF provisions. The commenter asserts that EPA is attempting to solve a problem that does not yet exist, at the risk of creating great administrative burden to both states and EPA.

b. EPA does not offer a reasoned justification for its change in its long-standing interpretation and application of RULOF.

EPA states that the “RULOF provision [its] proposing in this rule is consistent with how the EPA has approached RULOF in the implementing regulations previously.” The commenter believes that statement is simply not true. The commenter (2443-NMOGA) contends that EPA ignores the significant new procedural requirements being imposed in the RULOF process—and the new standards under which EPA will evaluate and approve RULOF demonstrations. The commenter asserts that proposed requirements and standards are new, more restrictive, and different than how EPA has interpreted and applied CAA section 111(d) for over forty years.<sup>106</sup> As described above, the commenter states that the EPA does not point to any prior examples of states submitting unsatisfactory state plans due to the alleged ambiguity of the current RULOF provisions—nor does EPA provide any actual record evidence of any kind to justify its departure from its longstanding interpretation. According to the commenter, EPA’s failure to acknowledge and justify this departure from its multi-decade interpretation of CAA section 111(d)(1) is arbitrary and capricious.<sup>107</sup>

Commenter (2399-GPA) urges EPA to drop its attempt to revise its rules to limit the discretion given states to implement its authority governing existing sources. According to the commenter, nothing in CAA section 111 provides EPA with the authority to impose what the December 2022 supplemental proposal calls “threshold requirements for considering Remaining Useful Life and Other Factors.” The commenter states that these “threshold requirements” are impermissible substantive conditions on when or how states may exercise the discretion Congress granted the states in considering RULOF to establish existing source emission standards under CAA section 111(d).

Moreover, the commenter (2399-GPA) recommends that EPA likewise not finalize these regulatory changes, which are directly contrary to the text of the statute and the cooperative-federalism structure of CAA section 111(d), which relegates the Agency to a limited role. The commenter argues that EPA cannot unilaterally re-define the roles that Congress assigned to each of EPA and the states through counter-textual interpretations of the terms “satisfactory plan” and “standards of performance.” Further, the proposed multitude of conditions and requirements that states would have to satisfy ill-conceived, lack a record basis, and are collectively so onerous that EPA would deprive states of an option that the commenter believes Congress clearly provided under the statute. For all these reasons (detailed below), the

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<sup>106</sup> See, *supra*, § II.A.

<sup>107</sup> See, e.g., *Fox Television Stations, Inc.*, 556 U.S. at 515.



commenter recommends that EPA withdraw what they contend are various unlawful conditions on the states' use of RULOF.

a. EPA's role under CAA section 111(d) is limited to establishing procedural regulations while states establish standards of performance.

The commenter (2399-GPA) argues that the EPA has erred in the December 2022 supplemental proposal by improperly seeking to alter the respective responsibilities of EPA and the states under CAA section 111(d)(1). In short, while EPA establishes emission limitations for new sources under CAA section 111(b), the commenter asserts that states establish emission limitations for existing sources under CAA section 111(d) with EPA playing a very limited procedural role. According to the commenter, CAA section 111(d)(1) only permits the Administrator to "prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the administrator a plan" for existing sources.<sup>108</sup> Those procedural regulations will differ from section 7410 only in that they "shall permit the [s]tate in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."<sup>109</sup>

The commenter (2399-GPA) further argues that CAA section 111(d)(1) does not authorize the Administrator to impose conditions on the approval of a state plan. Therefore, if such authority exists, it must come from section 110. Yet, the commenter states that the December 2022 supplemental proposed rule never examines EPA's authority under CAA section 110. However, the commenter notes that nothing in CAA section 110 provides EPA with any substantive powers in establishing CAA section 111(d)(1) emission limitations. Section 110(k) of the CAA governs EPA's review of state plans and actions on them. Of relevance, EPA must make a completeness find within 60 days indicating whether or not the state plan meets minimum statutory criteria,<sup>110</sup> and either approve, partially approve, conditionally approve, or disapprove a state plan depending upon whether "it meets all of the applicable requirements of this chapter."<sup>111</sup> Thus, the commenter provides that section 7410, as incorporated by section 7411(d), only authorizes EPA to create a procedural framework for the submission, review, and approval (or disapproval) of a state plan. The commenter asserts that approval or disapproval is based on statutory criteria only (i.e., "applicable requirements of this chapter"). The commenter contends that nothing in either section 7410 or section 7411(d) authorizes EPA to impose additional substantive requirements on when states may use RULOF and EPA has not identified any statutory ambiguity that it is interpreting.

Further, the commenter (2399-GPA) states that the D.C. Circuit very recently held that EPA's interpretation of CAA section 111(d) responsibilities is impermissible. EPA cites to *American Lung Association v. EPA*, 985 F.3d 914 (D.C. Cir. 2021) to summarize the 2019 ACE Rule litigation, 87 Fed. Reg. at 74,812, 74,817, but the commenter notes that it ignored the D.C. Circuit's explanation of the different roles that EPA and the states serve under CAA section

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<sup>108</sup> 42 U.S.C. § 7411(d)(1).

<sup>109</sup> Id.

<sup>110</sup> 42 U.S.C. § 7410(k)(1)(B).

<sup>111</sup> Id. § 7410(k)(3).

111(d). As the court stated: “Once the EPA identifies a best system that meets” the requirements of Section 111(a) “and calculates the degree of emission limitation it allows, the Clean Air Act leaves it to the [s]tates to set their own standards of performance for their existing pollution sources.”<sup>112</sup> “The cooperative-federalism design of [s]ection 7411(d) gives the [s]tates broad discretion in achieving those limitations.”<sup>113</sup> In fact, “under [s]ection 7411(d), the EPA does not impose the ‘best system of emission reduction’ on anyone. Instead, the commenter explains that each state decides for itself what measures to employ to meet the emission limits, and in so doing may elect to consider the ‘remaining useful life’ of its plants and ‘other factors.’”<sup>114</sup> Notably, the commenter believes that this was not merely a concurrence with an agency interpretation that EPA would be free to change in the future; this was the court’s explanation of CAA section 111’s unambiguous “statutory design.”<sup>115</sup> Thus, according to the commenter, both the text of CAA section 111, and a recent D.C. Circuit interpretation of that text, make it clear that Congress did not provide EPA with any authority to regulate how states establish existing source emission limits under CAA section 111(d) or to cabin the “broad discretion” provided to states under that statute.

Response II-19-15: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

### ***19.3.2 Opposition to Inclusion of the Remaining Useful Life and Other Factor Provisions***

Comment: Commenter (2399-GPA) asserts that the very premise underlying EPA’s claimed need for standards dictating how States account for a facility’s remaining useful life is incorrect. The commenter provides that nothing in CAA section 111(d) indicates that Congress intended for individual state considerations to avoid “inconsistent application ... across states.” Yet, the commenter states that the EPA bases its proposal on the unsupported notion that states must mimic the process EPA uses in establishing EGs. Hence, EPA proposes to compel each state to include “a source-specific BSER for the designated facility” that considers the same five factors used by EPA, and “must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the” emission guidelines and the resulting “standard must be in the same form (*e.g.*, numerical rate-based emission standard) as required by the EG OOOOc presumptive standard.” States must also provide analyses of why less stringent emission limitations do not “undermine the control objectives of the EG and CAA section 111(d) itself” and document “the time needed to purchase and install equipment required to comply, the time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance, the expected window of time needed to obtain approvals of outside agencies, the time needed to conduct any required community outreach or public hearings, as well as other potential factors.”

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<sup>112</sup> 985 F.3d at 962 (emphasis added).

<sup>113</sup> *Id.*

<sup>114</sup> *Id.*

<sup>115</sup> *Id.*

The commenter (2399-GPA) expresses concern that the December 2022 supplemental proposed rule provides no legal or record basis for any of these demands. Rather, EPA simply assumes that consistency in both process and results is demanded by CAA section 111(d). That is directly contrary to the “cooperative-federalism design of Section 7411(d)” that “gives the States broad discretion,”<sup>77</sup> and would reduce States to clerks performing paperwork exercises dictated by EPA. Further, EPA’s statement that its proposed process would “generally address all relevant information that states would reasonably consider in evaluating the emission reductions reasonably achievable for a designated facility,” is not supported by any record evidence. In fact, there is no discussion of the processes that states actually have used in setting existing source standards for any source categories. Thus, the December 2022 supplemental proposed rule declares that greater regulation of state analytical processes is required without any evidence of what states have done in the past, whether states have actually arrived at inconsistent results, and if so, that the inconsistencies are undesirable in some way. Instead, the commenter states that the December 2022 supplemental proposed rule seeks to establish standards based upon hypothetical scenarios and unsupported presumptions. Such an approach is clearly arbitrary and capricious.

Response II-19-16: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2399-GPA) asserts that, even if EPA had the authority to impose new conditions on states’ use of RULOF, the December 2022 supplemental proposed rule fails to provide a rational, record-based reasoning for those conditions. Instead, the commenter states that the December 2022 supplemental proposed rule bases its proposed revisions on a series of hypothetical scenarios that do not withstand serious scrutiny. Again, as the commenter provides elsewhere in their comments, they urge EPA to reconsider its approach.

The commenter (2399-GPA) understands the premise in EPA’s proposal is that its regulations regarding RULOF,<sup>116</sup> which were revised only four years ago, now lack “clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency.” States may demonstrate that applying the presumptive standard of performance (1) involves unreasonable costs due to a plant’s age, location, or process design, (2) physically impossible, or (3) involves other factors “that make application of a less stringent standard or final compliance time significantly more reasonable.”<sup>117</sup> The commenter states that the existing regulation employs a rule of reason – a very commonly used standard under the APA – and factor (3) is open-ended, and it must be given that it was Congress’ decision to allow states to consider unenumerated “other factors” instead of creating a definitive list of considerations.

According to the December 2022 supplemental proposed rule, however, 40 CFR 60.24a(e) “does not provide clear parameters for states on how and when to apply” RULOF. More specifically, the commenter (2399-GPA) notes that the EPA worries that “the reference to reasonableness in this provision are potentially subject to widely differing interpretations and inconsistent

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<sup>116</sup> 40 CFR 60.24a(e).

<sup>117</sup> Id.

application among states developing plans, and by the EPA in reviewing them” that “could effectively undermine the overall presumptive level of stringency envisioned by the EPA’s BSER determination and render it meaningless.” The commenter identifies multiple problems with this rationale.

First, the commenter (2399-GPA) states the rationale is entirely speculative. The December 2022 supplemental proposed rule has not identified any questions that have arisen from the actual application of 40 CFR 60.24a(e). In fact, the December 2022 supplemental proposed rule “did not identify any provision in any of the state oil and natural gas regulations that included a less stringent standard for equipment or operations with a shortened lifespan.” In other words, the commenter states that the EPA has no information showing that the proposed revisions are necessary or helpful, as no state has yet used the RULOF provisions for crude oil or natural gas sources.

Second, the commenter (2399-GPA) states that the concern that states “could” apply RULOF in a way that “effectively undermine[s] the overall presumptive level of stringency envisioned by the EPA’s BSER determination and render it meaningless,” is not only speculative, but it misunderstands CAA section 111(d)’s purpose. The commenter notes that the EPA’s BSER determination in its EGs is always a starting point for states under CAA section 111(d), and therefore, it could never be “meaningless” EPA’s proposal asserts. But most importantly, and contrary to the EPA’s concern, the Congress intended those states, under certain circumstances, be free to implement standards less stringent than EPA’s BSER determination. As one court explained, “[a]s with most legislation, the Clean Air Act amendments reflected a congressional compromise ... As one legislative compromise, the Clean Air Act has less stringent regulations regarding existing power plants as compared to newly constructed sources of electricity. In other words, existing plants were ‘grandfathered’ in recognition of the expense of retrofitting pollution-control equipment.”<sup>118</sup>

Thus, the commenter (2399-GPA) asserts that the entire purpose of CAA section 111(d)’s RULOF provision is to allow states to implement emission limitations less stringent than BSER where the states believe that the remaining useful life – and unenumerated “other factors” – warrant it. According to the commenter, revising the implementing regulations to prohibit, or severely restrict, a state’s ability to implement less stringent emission standards when considering “among other factors, the remaining useful life of the existing source,”<sup>119</sup> is contrary to the statutory purpose, the legislative compromise and the principles of federalism embodied in CAA section 111. As discussed above, the commenter states that the notion that existing source emission limits must hew to “the overall presumptive level of stringency envisioned by the EPA’s BSER determination,” is contrary to the statute’s text and structure, which provide the states’ with “broad discretion” in establishing existing source limits.<sup>120</sup> Thus, the commenter

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<sup>118</sup> *United States v. EME Homer City Generation LP*, 823 F. Supp. 2d 274, 279 (W.D. Pa. 2011) (citing CAA section 111(d)); see also *WEPCO v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) (citing legislative history justifying more lenient emission standards for existing sources).

<sup>119</sup> 42 U.S.C. § 7411(d).

<sup>120</sup> *Amer. Lung Ass’n*, 985 F.3d at 962.

contends that ensuring consistency between CAA section 111(b) new source standards and CAA section 111(d) existing source standards is not a legitimate rationale.

Third, the commenter (2399-GPA) provides that CAA section 111(d) does not indicate that Congress believed that consistency between or among state existing source standards was either necessary or desirable. As the D.C. Circuit explained, “each [s]tate decides for itself what measures to employ to meet the emission limits, and in so doing may elect to consider the ‘remaining useful life’ of its plants and ‘other factors.’”<sup>121</sup> The December 2022 supplemental proposed rule does not identify anything in CAA section 111(d) that justifies a contrary interpretation. The commenter suggests that this means that its concern that “the references to reasonableness in” 40 CFR 60.24a(e) “are potentially subject to widely differing interpretations and inconsistent application among the states,” is directly contrary to the statutory framework in CAA section 111 and the broad discretion afforded to individual states to decide “for itself.”

Fourth, the commenter states that the EPA and states have been implementing air emission standards that incorporate the “remaining useful life” of regulated facilities under the Regional Haze program for decades without any concern for “widely differing interpretations and inconsistent application among states developing plans.” As with CAA section 111(d), the commenter notes that the Regional Haze program gives states primary authority to establish air pollutant emission limitations that consider “the remaining useful life of the source” and other factors.<sup>122</sup> The commenter asserts that EPA and the states have collectively handled several dozen Regional Haze plans since 1999 without any indication that the methodology for state consideration of “remaining useful life” was confusing, inappropriately inconsistent, or frustrating the underlying goals of the Regional Haze program. Thus, according to the commenter, the December 2022 supplemental proposed rule’s claim that CAA section 111(d)’s implementing regulations require significant changes to resolve confusion or improper inconsistency surrounding RULOF is contradicted by the absence of such problems under the Regional Haze program.

Response II-19-17: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2446-IPAA) expresses concern that the RULOF provision is impractical, ignores low production wells, and limits state flexibility. The commenter requests that EPA develop a clear process to assess RULOF. The commenter notes that EPA proposes that state plans should include source by source decisions on the application of RULOF. The commenter believes such an approach would be impractical due to overlapping actions. The commenter

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<sup>121</sup> Id.

<sup>122</sup> 42 U.S.C. § 7491(g)(2); see also 40 CFR 51.301 (“remaining useful life” included in the definition of Best Available Retrofit Technology); 60 CFR 51.308(d)(1)(i)(A) (States consider “remaining useful life” in establishing Reasonable Progress Goals); 60 CFR 51.308(e)(1)(ii)(A) (determining Best Available Retrofit Technology); 308(f)(2)(i) (emission reduction measures that consider the “remaining useful life”).

notes that at the same time these individual decisions would be considered, the state would be developing its overall plan and would not know whether EPA would approve it.

The commenter (2446-IPAA) also notes that the proposed rule would only allow that cost unreasonableness be considered in a state's demonstration that a source's remaining useful life based on its retirement date reasonably warrants a less stringent standard for only the following types of designated facilities: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps. A cost unreasonableness determination would not be allowed for any other designated facility types. The commenter expresses concern that this arbitrary position reflects EPA's intention to limit state flexibility. The commenter notes that increasing operating costs for small wells can have a significant impact on their economic viability. The commenter asserts that this framework, ignores low production wells thereby making the facility uneconomic and drives it to shut down. The commenter reports that many low production wells can continue to operate for decades at production rates that may be in the less than 2 boe/day range while posing minimal methane emissions threats. The commenter contends that federal regulation should not be the cause of their demise and states should have the authority to provide for a regulatory framework that allows their continued operation until their normal end of life.

The commenter (2446-IPAA) notices that EPA seems inordinately concerned that different states could create different RULOF approaches for similar facilities. However, the commenter provides that the nature of oil and natural gas production results in different production challenges that do not appear evident from casual comparisons. The commenter encourages EPA to recognize program differences and the resulting emissions management and economic implications. As a part of the federal state partnership, the commenter urges EPA not to impose uniform regulatory requirements on state plans after the state has addressed the different operations under its jurisdiction.

In another instance of EPA trying to limit state ability to develop regulatory approaches – including RULOF decisions – the commenter (2446-IPAA) notes that the EPA proposes that states must use EPA's BSER development approach. However, the commenter asserts that there is no absolute guarantee that EPA's analytical approach is sound or accurate for every state. Moreover, as shown previously with regard to the fugitive emissions analysis, the commenter suggests that the EPA is so wedded to its component count approach that it distorts results. The commenter reports that states may choose to assess issues differently and thereby produce different approaches based on their experience – which in the context of regulating existing sources is far more comprehensive than EPA's experience since its authority is primarily directed at new sources. Perhaps more significantly, the commenter asserts that EPA has effectively applied its NSPS BSER analysis to its CAA section 111(d) assessment where existing sources are affected. According to the commenter, this transposition of a new source analysis to existing sources fails to follow the Congressional intent evident throughout the CAA that existing sources need to be treated differently than new ones. The commenter contends that the EPA rather cavalierly concludes that its new source BSER applies to existing sources without ever making a full analysis. In these regulations applying to oil and natural gas production operations, the commenter has consistently presented information to EPA that the declining nature of oil and natural gas production requires EPA to assess low production wells differently because – at a minimum – the ability of these sources to absorb additional costs differs significantly from new

sources. The commenter states that Congress went further than just distinguishing between new and existing sources by adding the RULOF process to address even more unique problems. According to the commenter, the EPA fails to meet the task demanded of it in addressing existing source BSER and needs to revise its assessments.

Response II-19-18: Please see RULOF discussion in section XIII.C.3 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2037-Climate Action et al) states that, under CAA section 111(d), states have a role in tailoring rules that implement EPA determined standards as applied to particular facilities. The commenter reports that many facilities subject to controls under CAA section 111 are operations that emit only when operating, then are closed and stop emitting at the end of the facilities' useful life. Accordingly, the statute recognizes the concept of "useful life" as a legitimate factor states may consider.<sup>123</sup> For example, a state might determine that an aging power plant, nearing the end of its design life and worth only \$1 million because it can generate power for only one more year, should not be required to install a \$500 million pollution control system that would take months to construct.

But the commenter (2037-Climate Action et al) notes that oil and gas wells, while also subject to federal emission standards under section 111, are quite different from facilities like power plants. If not properly sealed, a well that has little or no remaining value can continue to emit pollutants – the CAA's focus – regardless of whether it is operating, idled, or abandoned. In terms of potential to emit, an unsealed well might be immortal. "Useful life" defies simple application. The commenter requests that EPA define as clearly as it can what conditions will support a decision to exempt wells based on 'remaining useful life,' lest that become a barn door through which resistant jurisdictions can flee without causing facilities to meet federal emission standards. The commenter recommends that EPA should define "useful life" to include the period in which a facility remains in a condition that could emit pollutants, regardless of operational status. For an oil or gas well, the commenter asserts that any condition short of full closure and sealing must be a circumstance that cannot be exempted from emission standards.

The commenter (2307-Climate Action et al) explains that the problem is not merely theoretical. The commenter states that the future life of a well in the petroleum sector is uncertain for at least two reasons. First, the volatile nature of oil and natural gas prices often turn long idle, low-producing wells into valuable assets that receive new investment, a "workover," or are simply put back online because potential returns make the ongoing maintenance and energy

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<sup>123</sup> 42 U.S.C. section 7411(d) provides, in pertinent part, that "Regulations of the Administrator under this paragraph shall permit the [s]tate in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

consumption cost-effective again. The commenter states for example that California has certainly seen a lot of well re-working in response to rising oil prices.

Secondly, the commenter (2307-Climate Action et al) notes that if the past century teaches us anything, it is that the industry can make incredible, sometimes unexpected technological progress. The commenter notes that they have seen dormant wells be profitably redrilled or re-worked using modern drilling and fracking techniques. As a result, wells and fields that had been written off as having little or no useful life became production stars, not because product prices rose, but because production techniques improved.

Response II-19-19: Please see RULOF discussion in section XIII.C.3 of the final preamble.

The EPA finalizes well closure requirements as part of the fugitives emissions monitoring and repair standards in EG OOOOc. Specifically, owners and operators are required to submit a well closure plan to the Administrator within 30 days of the cessation of production from all wells located at the well site as specified in §60.5420c(a)(4)(i). The well closure plan must include a description of the steps necessary to close all wells at the well site, including permanent plugging of all wells; a description of the financial requirements and disclosure of financial assurance to complete closure; and a description of the schedule for completing all activities in the well closure plan. Owner and operators are required to submit a notification as specified in §60.5420c(a)(4)(ii) of intent to close the well site to the Administrator 60 days before the beginning of well closure activities. Furthermore a survey of the well site using OGI is required, including each closed well, after completing all well closure activities outlined in the well closure plan. If any emissions are imaged by the OGI instrument, then steps must be taken to eliminate those emissions and the source of emissions must be resurveyed. These steps are required to be repeated until no emissions are imaged by the OGI instrument.

The EPA recognizes that the oil and natural gas industry has ongoing maintenance and equipment replacement schedules to ensure proper and safe operations. NSPS OOOOb includes definitions for “reconstruction” and “modification” and specifies when those definitions are met. If a designated facility triggers reconstruction or modification, that source would become an affected facility under NSPS OOOOb. Please refer to the final preamble and NSPS OOOOb for additional discussion.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

### ***19.3.3 Proposed RULOF Criteria***

#### **19.3.3.1 Retirement Dates and Capital Expenditures**

Comment: Commenter (2222-WDXNR) recognizes that an ‘outermost retirement date’ may be reasonable for affected source categories. However, the commenter contends that it is important that EPA solicit public comment on the appropriateness of a date prior to issuing a final rule.



Response II-19-20: Please see RUOF discussion in section XIII.C.3 of the final preamble.

Comment: Commenter (2410-CA AG et al) supports the proposed requirements concerning retirement dates and capital expenditures. The commenter suggests that EPA explain why it is proposing to limit what they consider to be the unreasonable cost criterion to four types of oil and gas facilities. The commenter notes that the state plan must identify the source's retirement date and explain why this date qualifies for imposition of a less stringent standard (i.e., why the cost of control is unreasonable in relation to the retirement date and demonstrate unreasonable cost of control for each of the identified compliance options. The commenter notes that EPA is proposing that the only cost factor that should be considered is whether there is a significant capital investment required to design, purchase, and install equipment. The commenter notes that because controlling methane pollution would not require a significant capital investment for certain types of designated oil and gas facilities, under EPA's proposed approach a less stringent standard based on unreasonable cost would be available for the following types of designated facilities only: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps.

Conversely, commenter (2399-GPA) argues that CAA section 111(d)(1) prohibits the proposed "capital investment" limitations to the remaining useful life analysis. The commenter suggests that the EPA's restriction on consideration of cost is likewise unsupported and contrary to the CAA. The commenter states that the December 2022 supplemental proposal "proposes that the only cost factor that" states should be permitted to "consider in a remaining useful life determination of cost unreasonableness is whether there is a significant capital investment required to design, purchase, and install equipment." Under this standard, "EPA does not believe that all types of designated facilities should be eligible for a determination of unreasonable costs associated remaining useful life." Therefore, according to the December 2022 supplemental proposed rule, only "oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps" would be eligible for a state's consideration of remaining useful life and a "cost unreasonableness determination would not be allowed for any other designated facility types."

Again, the commenter (2399-GPA) states that the EPA does not identify any legal authority for such a requirement. Indeed, the commenter believes that CAA section 111(d)(1) expressly prohibits the proposed requirement: "Regulations of the Administrator under this paragraph shall permit the [s]tate in applying a standard of performance to any particular source ... to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies." With respect to the state's consideration of remaining useful life, the commenter suggests that this language is unconditional and unlimited. According to the commenter, the state may consider the remaining useful life of "any particular source" or any "existing source." The commenter adds that the only limitation is placed on the Administrator, not the states. The Administrator "shall permit" the consideration of any source's remaining useful life without any suggestion that Congress granted the Administrator the discretion to constrain the states.

Response II-19-21: Please see RUOF discussion in section XIII.C.3 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

### 19.3.3.2 Impacts of Less Stringent Standards Under RULOF on Impacted Communities

Comment: Commenter (2343-NYU School of Law) recommends that EPA instruct states on how to identify affected communities, how to decide who is vulnerable, and how to analyze impacts to vulnerable communities from adopting less stringent standards based on the facility's remaining useful life.

The commenter (2343-NYU School of Law) recommends that EPA clarify that states must consider the distributional impacts of both the proposed less stringent standard and the alternative if the variance is not granted (i.e., the presumptive level of stringency in the applicable emission guideline from the final rule). For each analysis, the commenter recommends that benefits to each vulnerable community should be disaggregated and, whenever possible, the states' analyses should be quantitative to facilitate comparison. The commenter recommends that EPA help states by providing any available information on quantifying the health harms from the relevant pollutants.

The commenter (2343-NYU School of Law) asserts that once a state has analyzed the allocation of benefits under both scenarios, it would then be in a position to make an informed decision as to whether to pursue a less stringent standard. And, from the perspective of EPA, disaggregating the benefits of each proposed variance would put the agency in a position to evaluate whether ratifying the less stringent standard would harm vulnerable communities, which is prohibited by the Supplemental Proposal when states are relying on a facility's remaining useful life.

Response II-19-22: In the final Implementing Regulations rulemaking, the EPA explained its decision to not finalize the requirement referred to by the commenter. 88 FR 80480 (November 17, 2023). Accordingly, the EPA is also not finalizing such a requirement in this action.

Comment: Commenter (2410-CA AG et al) strongly supports requiring states to consider impacts of a less stringent standard on communities located near the facility. The commenter states that Congress's inclusion of the "other factors" language indicates that additional factors other than remaining useful life could be relevant to determining the appropriate performance standard for individual facilities. Also, the commenter contends that CAA section 111(d)'s language directing that EPA "permit" states to consider remaining useful life indicates that the agency has some discretion regarding how states can apply remaining useful life, among other factors, in establishing performance standards. Given that the purpose of regulating stationary source pollution under CAA section 111 is to address emissions that endanger public health and welfare, the commenter believes that requiring that states take into account how excess pollution (above the level reflected in application of the BSER) may impact the health and welfare of local communities is consistent with the statutory design. Finally, the commenter asserts that EPA's oversight authority in ensuring that state plans do a "satisfactory" job of adopting standards that

reflect the degree of emission reduction from applying the BSER provides additional support for requiring that potential harms from exceeding the EG be adequately considered.

Response II-19-23: In the final Implementing Regulations rulemaking, the EPA explained its decision to not finalize the requirement referred to by the commenter. 88 FR 80480 (November 17, 2023). Accordingly, the EPA is also not finalizing such a requirement in this action.

Comment: Commenter (2428-API) applauds and supports EPA’s overall objective of addressing potential disparate impacts. However, the commenter recommends that EPA consider the proposed requirements to require consideration of EJ impacts because the proposed requirement is not legally supportable. To begin, the commenter notes that the term “other factors” is a generic term in and of itself. But as used in the context of CAA section 111(d), the commenter does not believe that term reasonably means that EJ may be considered in standard setting. First, they provide that CAA section 111(d)(1) states that EPA’s regulations “shall permit” states to consider RULOF in setting existing source emissions standards. This language places responsibility on the states, in the first instance, to determine the “other factors” they deem relevant in setting standards upon consideration of RULOF. According to the commenter, EPA’s role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state’s identification and consideration of other factors is reasonable, the commenter states that then EPA cannot reject the state’s determination on the grounds that EPA believes the term “other factors” should be given a different meaning. The commenter argues that the EPA’s proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA’s broader “cooperative federalism” scheme.

Second, the commenter (2428-API) notes that the term “other factors” must be interpreted in context. By specifying that states may consider “remaining useful life,” Congress indicated that source-specific factors are relevant to the states’ determinations. The commenter contends that, since the term “other factors” is a catch-all phrase that follows the more specific instruction to consider a source specific factor, the term “other factors” must be construed in a similar light. They add that this interpretation is particularly true given that “standards of performance” under CAA section 111(a)(1) are technology-based standards that reflect the BSER determined applicable to affected facilities. The commenter asserts that the EPA’s proposed interpretation of “other factors” is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, the commenter (2428-API) states that CAA section 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, the commenter notes that it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, they state that CAA section 112(f) requires impacts to health and the environment to be considered in determining whether Maximum Achievable Control Technology (MACT) based national emission standards for hazardous air pollutants (NESHAP) are adequately protective to health and the environment. The statute specifies that EPA must provide an “ample margin of safety,” as defined in the Benzene Waste NESHAP. CAA section 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the NAAQS established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, the commenter (2428-API) points out, CAA section 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA section 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. The commenter states that the EPA's goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA section 111 standard setting process.

The commenter (2428-API) adds that the EPA also states that not considering impacts would be “antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally.” The commenter notes that there is no doubt that protecting public health and welfare are overarching goals of the CAA. However, the commenter does not believe that aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, the commenter contends that CAA section 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, the commenter (2428-API) notes that the EPA argues that considering EJ impacts in state standard setting is consistent with the definition of “standard of performance” in CAA section 111(a)(1) and that states must consider such impacts “just as the EPA is statutorily required to take into account these factors in making its BSER determination.” More specifically, EPA asserts that the definition of “standard of performance” “requires the EPA to take into account health and environmental impacts in determining the BSER.” The commenter respectfully disagrees and asserts that there is no language in the CAA section 111(a)(1) definition of “standard of performance” that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, the commenter (2428-API) states that standards of performance are to primarily be based on technology and cost considerations. The only exception is that “nonair quality health and environmental impact[s] and energy requirements” also must be taken into account in setting standards of performance. CAA section 111(a)(1). The commenter believes that the statute thus is clear that the only “health and environmental impacts” that may be considered in setting a standard of performance are nonair health and environmental impacts. The commenter notes that the provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, the commenter asserts that it cannot be grounded in the requirement to consider nonair quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, the commenter believes that the EPA is precluded from interpreting general language in CAA sections 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all these reasons, the commenter (2428-API) requests that EPA reconsider the proposed requirement to require consideration of environmental justice (EJ) impacts when states or EPA implement the RULOF provision.

Response II-19-24: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2399-GPA) contends that the proposed health and welfare components of state emission limitations have no legal or record basis and are impermissibly vague. The commenter provides that the December 2022 supplemental proposed rule imposes several additional demands on states related to impacted communities. These include requiring states “to consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions,” implement “meaningful engagement requirements,” and “describe the health and environmental impacts anticipated ... along with any feedback the state received during meaning engagement.”

The commenter (2399-GPA) supports the important policy goal to protect impacted communities, but not one that EPA is authorized to require states to address as part of a state’s consideration of RULOF. The commenter notes, however, that the text of CAA section 111(d)(1) speaks only of a state’s “consideration” of “the existing source to which such standard applies.” Congress did not require or authorize any other considerations, such as impacts to health or welfare – impacts that Congress frequently included in various CAA analyses when it chose to do so. The commenter states that CAA section 111(d) is specific as to what states may consider (“among other factors, the remaining useful life of the existing source”) and never compels states – through words like “shall” or “must” – to consider anything at all. The commenter suggests that, had Congress intended to direct states to consider generalized “overall health and welfare objectives” in CAA section 111(d) it would have done so.

In addition, the commenter (2399-GPA) states that the record EPA has proffered here does not support the specific mandate that EPA would impose on states through this regulation. First, the commenter notes that the December 2022 supplemental proposed rule declares that these new requirements are necessary “[i]n order to address the potential exacerbation of health and environmental impacts to vulnerable communities as a result of applying a less stringent standard.” The commenter provides that EPA has not, however, offered data or analysis regarding the likelihood of any designated facility, or group of designated facilities, of impacting the health of any vulnerable community or the extent of any such potential impacts. Therefore, there is no record basis supporting the proposal.

Second, the commenter (2399-GPA) provides that the proposed regulatory text is significantly different in several important respects from the preamble explanation providing the supporting rationale. The proposed regulatory text requires a state to demonstrate that the “increased emissions for the duration of the remaining useful life will not result in negative impacts to the surrounding communities, including those most affected by and vulnerable to the health and

environmental impacts of the plan.” Again, the commenter states that the EPA and states may choose to conduct this type of analysis that may offer significant data for the government to consider in fashioning policy, but this language is significantly problematic here in the following respects:

- The state must make some demonstration that the facility’s remaining life emissions “will not result in negative impacts to surrounding communities.” The proposed language does not define a “negative impact” or explain what a state must demonstrate. Neither the preamble nor the proposed regulatory language describes how a state may satisfy EPA that these emissions are acceptable.
- The preamble claims that states must analyze emissions for vulnerable communities, which are not defined. The proposed regulatory language requires a much broader analysis; one that includes all “surrounding communities.” Neither the preamble nor the proposed regulatory language defines “surrounding communities,” so as proposed, states will have no way of knowing how far their analysis must go.
- The need to provide some analysis of emissions, presumably including their concentration and dispersion, over the facility’s remaining life implies that some form of air modeling will be required. For many sources this will be a significant burden layered onto the additional burdens of these regulations imposed on sources and State regulators. However, for other designated facilities, which may include individual pieces of equipment, such as a pneumatic controller, neither the preamble nor the proposed regulatory language provides any indication of what kind of demonstration EPA is expecting.

Therefore, the commenter (2399-GPA) believes that the December 2022 supplemental proposed rule provides a defective rationale for one set of health and welfare requirements while proposing regulatory language that would impose very different requirements. The requirements in the proposed regulatory language are never explained and, therefore, lack the necessary “reasoned explanation.” And, finally, “[e]lementary administrative law norms of fair notice and reasoned decision-making demand that” an agency define what it requires of regulated parties. Here, the proposal (whether that be the December 2022 supplemental proposed rule’s preamble or the proposed regulatory language) does not define key terms (“vulnerable communities,” “surrounding communities,” “those most affected by and vulnerable to the health and environmental impacts of the plan,” “negative impacts”), the type of analysis required, such as air modeling or some unspecified qualitative analysis, or what a state must demonstrate to EPA in order to obtain approval. Therefore, according to the commenter, even if EPA had the legal authority to impose these requirements, they lack record support, are unexplained, impermissibly vague, and otherwise arbitrary and capricious.

Response II-19-25: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

### 19.3.3.3 Contingency Requirements

Comment: Commenter (2399-GPA) states that the December 2022 supplemental proposed rule also proposes “contingency requirements” that would effectively convert a state’s determination that applying EGs to a facility is not reasonably cost-effective into a binding permit term. Two such examples provided in the December 2022 supplemental proposed rule would be that, (1) if low oil prices would make application of the emission guidelines to a facility unreasonably expensive then a federally enforceable permit conditions would require the facility to shut down if oil prices increased (making the emission guidelines more cost effective), and (2) if a short remaining useful life makes application of the emission guidelines unreasonably cost-effective, then the facility’s retirement date must become a federally enforceable permit condition requiring it to shut down on that date.

The commenter (2399-GPA) urges EPA to reconsider this approach. According to the commenter, nothing in the statute authorizes these restrictions on defining the implementation of RULOF – and none is cited in the proposal. Nor does the record for the proposal indicate that such conditions have been used or would be needed. According to the commenter, these “contingency requirements” address purely hypothetical scenarios without any consideration of what states have done in setting emission limits under CAA section 111(d). In addition, EPA previously rejected the requirement to make a facility’s retirement date a federally enforceable permit condition, in a similar circumstance. Under the 2005 Regional Haze Rule, EPA rejected a commenter’s request that, “to the extent that assertions regarding a plant’s remaining useful life influences the BART decision, there must be an enforceable requirement for the plant to shut down by that date.”<sup>124</sup> The commenter provides that the EPA rejected the request, explaining that the CAA would require such a plant to either shut down at the retirement date, face an enforcement action, or install best available retrofit technology (BART) controls. In other words, the facility would be able to adapt to any changes in condition. The commenter states that the December 2022 supplemental proposed rule not only changes EPA’s position on this issue but does so without explanation or even a recognition that it is changing its position.

Response II-19-26: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2410-CA AG et al) notes that where a state seeks to rely on a designated facility’s operational conditions—such as the source’s remaining useful life or restricted capacity—as a basis for setting a less stringent standard, EPA proposes to require enforceable conditions for that facility in the state plan to address the scenario where a source’s operations change. This requirement would address operating conditions such as operation times, operational frequency, process temperature or pressure, and other conditions that are subject to the discretion and control of the designated facility. The commenter supports imposing contingency requirements in instances where a less stringent standard is based on an operational constraint within a facility’s control. The commenter agrees with EPA that, in the absence of an

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<sup>124</sup> 70 Fed. Reg. 39,104, 39,127 (July 6, 2005).

enforceable requirement, a subsequent (unforeseen) change in a facility's operations could result in foregone emission reductions and undermine the level of stringency in the EG.

Response II-19-27: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### 19.3.3.4 Fundamentally Different

Comment: Commenter (2399-GPA) notes that, to satisfy RULOF, EPA has created criteria based on cost, physical impossibility, or technical impracticability, and “other factors specific to the facility (or class of facilities) that are fundamentally different from the factors considered in the determination of the best system of emission reduction” in EPA’s EGs.

The commenter (2399-GPA) urges EPA to reconsider the “fundamentally different” criteria, as they believe it is flawed in at least two ways. First, “fundamentally different” is just as vague and ambiguous as “reasonable,” the word that EPA claims requires additional definition. Second, it practically requires that a state demonstrate that EPA’s presumptive standards are arbitrary and capricious in a specific application. According to the commenter, nothing in CAA section 111(d) indicates that Congress intended for states to consider RULOF only in extreme, outlier scenarios that are “fundamentally different.”

In fact, the commenter (2399-GPA) provides that the December 2022 supplemental proposed rule illustrates how impractical RULOF would become under this “fundamentally different” criterion by claiming that states must demonstrate that BSER costs “would be exorbitant, greater than the industry could bear and survive, excessive, or ‘unreasonable.’” In a more specific example, the December 2022 supplemental proposed rule asserts that, where EPA estimated that the cost-effectiveness of the wet seal centrifugal compressor emission standard to be \$711 per ton of methane removed, to demonstrate unreasonable cost, a State would have to determine that for an “affected facility in their state, the cost effectiveness was \$71,000 per ton of methane removed.” (emphasis added). The commenter contends that the notion that states can only justify unreasonable costs by demonstrating, to EPA’s satisfaction, that cost-effectiveness will be two orders of magnitude higher than the BSER estimate has no basis in the statute, is patently arbitrary and capricious, and would effectively preclude any state from ever establishing emission limitations based on methods that Congress authorized under CAA section 111(d). The December 2022 supplemental proposed rule protests that it only provided the example “for illustrative purposes” and that states do not necessarily need to demonstrate that costs will “be two orders of magnitude higher than the presumptive standard to be considered unreasonable.” However, the commenter notes this is the only example that the December 2022 supplemental proposed rule provided using a cost-effectiveness comparison. Both EPA and courts could refer to this example as indicating that EPA’s interpretation of “unreasonable costs” should require a cost difference so extreme that even four or five times the BSER cost-effectiveness (*i.e.*, approximately \$2,850 to \$3,550 per ton of methane removed) would not be enough to be “unreasonable.”



Comment: Commenter (1633-NRDC) with the supplemental proposal that variances for remaining useful life or other factors should not be granted without a demonstration that a specific source is “fundamentally different” from the other members of the category or subcategory to which it belongs under EPA’s emission guideline. “Fundamentally different” means more than just some difference. It means that the source must be so different that it is not rational to include it in the same set as the other sources in the category or subcategory.

Commenter (1633-NRDC) notes that the proposed rules elaborate the three conditions set forth in the 1975 rules to incorporate this requirement of fundamental difference. The proposed rules explain, for example, that a minor variation in cost-per-ton of emission controls will not make a source fundamentally different from the other members of the category. Some source-to-source cost variation is inevitable in any category. The agrees with EPA’s examples that suggest what is required is an order-of-magnitude difference in cost-per-ton.

Commenter (1633-NRDC) also supports the proposed distinction between capital and operating costs. EPA may determine in an emission guideline that a standard which entails a significant capital cost has a reasonable cost per-ton and is warranted by health and environmental benefits because the capital expenditure can be amortized over a given number of years of operation. The same requirement may have a substantially higher cost-per-ton and may deliver fewer health and environmental benefits if applied to a source that will imminently retire. If that difference is on the order-of-magnitude scale mentioned above, it may be possible for the source to demonstrate to the state, and the state to demonstrate to EPA, that this source is in fundamentally different situation compared with the longer-lived sources on which the guideline was based, and that a variance is appropriate.

Commenter (1633-NRDC) adds conversely, requirements such as leak detection and repair involve operating costs but no significant capital costs. Those annual or per-instance operating costs do not vary with the remaining lifetime of the source. Their cost-effectiveness requires no amortization period. For these requirements there is no basis for determining that a source scheduled to retire soon faces fundamentally different costs than those faced by the category’s general membership. The commenter supports EPA’s proposed determination that remaining useful life variances cannot be granted for LDAR and similar requirements.

Commenter (1633-NRDC) supports EPA’s proposed requirement that retirement dates be enforceable for sources applying for remaining useful life variances.

Response II-19-28: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2410-CA AG et al) notes that the current regulations contain certain threshold criteria that must be triggered for a state to establish a less stringent standard based on the remaining useful life of a facility (or other factors). The commenter contends that while

retaining the threshold requirements in the current regulations that refer to an unreasonable cost of control resulting from plant age, location, or basic process design or physical impossibility of installing necessary control equipment, EPA proposes to modify the current “catchall” third criterion to apply if a state demonstrates that there are other factors specific to the facility (or class of facilities) “that are fundamentally different from the factors considered in the establishment of the emission guidelines.” For example, if the state could demonstrate that the cost-per-ton of pollution reduction at a particular facility would be significantly higher than estimated by EPA in its BSER analysis, that facility may be evaluated for a less stringent standard. The commenter notes that states would not be permitted to invoke the RULOF provision based on minor, non-fundamental differences. The commenter supports EPA’s revisions to the threshold requirements for applying RULOF. The commenter contends that the “fundamentally different” language adds clarification on applying the other factors and is consistent with variance provisions in the Clean Water Act and other environmental laws.

Response II-19-29: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### 19.3.3.5 Variances

##### *Variance Guidance*

Comment: Commenter (1633-NRDC) asserts that EPA must define clear rules to guide states and other stakeholders on when a variance is warranted or what alternative emission limit and compliance deadline should apply. The commenter believes that an absence of rules gives rise to the potential for unequal treatment of similar cases by states or EPA and may incentivize a race to the bottom at the expense of public health and environmental protection. The commenter notes, as explained in the proposal, the 1970 CAA made no provision for source-specific variances. The commenter provides that EPA’s 1975 implementation rules allowed states some leeway for differentiation for specific sources within a category or subcategory through a variance process.

Response II-19-30: Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

##### *Variance Legal Considerations*

Comment: Commenter (2433-EDF et al) recommends that RULOF provisions that allow variances are the exception rather than the norm to maintain the regulation integrity. The commenter strongly supports the December 2022 supplemental proposal’s RULOF provisions which outline the application and review process for variances, as well as the criteria required for each such variance. The commenter provides comments on the processes (etc) in the following paragraphs.

a. The application and review process for RULOF variances

Under the proposal, a state must identify and explain the basis for the variance request, identify all other possible systems of emission reduction for the source, and select an alternative “best system” from this list, as well as a degree of emission limitation based on that system. The state must then impose an enforceable performance standard for the source that reflects the degree of emission limitation associated with the alternative best system and that otherwise complies with CAA section 111(d)’s implementation regulations.

The commenter (2433-EDF et al) asserts that it is critical that in the final rule, EPA establish these provisions as binding requirements (as it has done in the proposal) rather than merely presumptive suggestions (an option for which it requests comment). The commenter believes that non-binding provisions would open the door for states to grant variances for various other reasons that EPA would have to assess on a case-by-case basis. As explained below, the commenter contends that was exactly the problem with the 1975 and 2019 implementing regulations. The commenter believes that the problem would be exacerbated by the large number of sources in the oil and natural gas sector; administrative necessity by itself is sufficient reason for EPA to put binding requirements on variances.

The supplemental proposal also maintains certain conditions that are essential to prevent abuse of the RULOF provision. First, it prohibits states from issuing variances merely because a source wishes to use a different system of emission reduction than the agency’s designated “best system.” The standard set by the state must achieve the degree of emission reduction as provided by the emissions guideline unless the conditions for variances are met. Second, the proposal requires that any operating conditions serving as the basis for a variance be included in the plan as federally enforceable requirements for the source in question. Third, with respect to age-based variances in particular, the proposal establishes a heightened standard of specificity, requiring states to demonstrate that the unit’s retirement date conflicts with at least one of five factors needed to fully satisfy EPA’s guidelines. The commenter (2433-EDF et al) acknowledges that together, these requirements will help prevent abuse of RULOF-based variances while still providing the regulatory flexibility that Congress contemplated in enacting CAA section 111(d).

b. The conditions for receiving RULOF variances.

The commenter (2433-EDF et al) believes that the proposal places reasonable limitations on the circumstances under which variances may be granted. The commenter reports that the 1975 and 2019 regulations stated, without elaboration, that states may establish more lenient standards for an affected source if they demonstrate at least one of three conditions:

- (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
- (2) Physical impossibility of installing necessary control equipment; or

(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.<sup>125</sup>

The commenter (2433-EDF et al) asserts that this language gave states too much room for interpretation and does little to prevent state-based variances from being granted to sources that exhibit no exceptional characteristics compared to the other members of their category or subcategory. The commenter supports the additional restraints that EPA has included in the December 2022 supplemental proposal on the issuance of variances that serve a critical function by helping to ensure that variances are reserved for only truly extraordinary circumstances. Below, the commenter discusses the conditions that EPA has established and provides recommendations for further refinement and improvement of the RULOF provisions from what was proposed in the December 2022 supplemental proposal.

i. Condition #1: Variances based on compliance costs.

The commenter (2433-EDF et al) urges EPA to remove or limit “unreasonable costs of control resulting from . . . basic process design” as a basis for granting variances in the first clause.<sup>126</sup> The commenter acknowledges that this term is not new to EG OOOOc—it also appeared in the 1975 and 2019 regulations—however the commenter questions what purpose it serves, or what it even means. If a source’s “basic process design” requires using outdated technology that cannot incorporate the BSER at a reasonable cost, then that is no reason to grant the source a relaxed standard, particularly since EPA’s “best system” *must* reflect reasonable costs as a general matter. The commenter contends that it does not contravene Congress’s intent if certain obsolete sources end up retiring rather than incurring the costs required to install the “best system” technology, particularly where doing so would not result in stranded assets. The commenter recommends that EPA thus limit the first category of variances to unreasonable costs based on plant age or location. Alternatively, the commenter recommends that the agency provide clearer guidance and limitations on when states may grant variances reflecting “basic process design” considerations.

The commenter (2433-EDF et al) also strongly supports EPA’s proposal to limit possible RULOF variances based on compliance costs resulting from a source’s remaining useful life to only four subcategories of sources in the oil and gas source category: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps. The commenter agrees with EPA’s explanation that these are the only sources that must make significant capital expenditures to comply with the proposed EG OOOOc standards.

The commenter (2433-EDF et al) also supports EPA in —appropriately—not permitting variances based on age-related compliance costs for affected facilities other than the four types noted above. In the commenter’s submission on the November 2021 proposal, they explained that Congress’s primary reason for enacting the RULOF provision was to avoid imposing otherwise unreasonable capital costs on an aging facility that will close before the period assumed for amortizing those costs for other members of the relevant category or subcategory.<sup>127</sup>

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<sup>125</sup> 40 CFR 60.24(f), 60.24a(e).

<sup>126</sup> Proposed 40 CFR 60.5365c(a)(1).

<sup>127</sup> See 2022 Joint Environmental Comments, *supra* note 1, at 214–15.

The commenter states that this concern simply does not apply where compliance requires no significant upfront capital investment in the first place—which is true for all the EG OOOOc-affected sources apart from oil wells with associated gas, storage tanks, and pneumatic equipment. The commenter agrees that the supplemental rule’s RULOF provisions therefore adhere to Congress’s intent and ensure that sources do not receive a windfall in terms of relaxed standards merely because they are old and nearing retirement.

The commenter (2433-EDF et al) describes another way to see the same point: the annualized cost-effectiveness of a measure that has no upfront capital investments is the same regardless of the remaining useful life of the source. Since EPA determined the annualized cost-effectiveness of the measure to be reasonable in setting BSER, that annualized cost-effectiveness remains reasonable for a source with a relatively short remaining useful life. In other words, the commenter states that remaining useful life does not create any difference between the aging facility and EPA’s BSER determination under these circumstances, let alone a “fundamental difference.”<sup>128</sup>

The commenter (2433-EDF et al) asserts that even for sources that do require capital investments for compliance, the supplemental rule appropriately establishes at least *three* other important limiting conditions before they can qualify for a variance. *First*, as EPA explains in the preamble, costs associated with a source’s remaining useful life must not merely increase for a variance to be warranted, but must rise to the level of *unreasonableness*, as determined by the agency, in terms of dollars spent per ton of pollution abated. The commenter agrees that this is wholly appropriate as it responds to Congress’s concern about stranded assets without allowing sources to wrongly benefit from reasonable increases in control costs and does not account for a particular sources’ margin of profitability, a consideration that should not be relevant to pollution control decisions. As already noted, a cost differential must be fundamental, not minor, to be considered unreasonable.

*Second*, the supplemental proposal requires sources receiving age-based variances for any reason—including reasons unrelated to cost—to demonstrate that “[t]he increased emissions for the duration of the remaining useful life will not result in negative impacts to the surrounding communities, including those most affected by and vulnerable to the health and environmental impacts of the plan.” The commenter (2433-EDF et al) believes that this is a critically important guardrail that appropriately balances the need for regulatory flexibility with CAA section 111’s lodestar of health and environmental protection, and it also specifically requires an evaluation of how vulnerable communities will be affected by variances. The commenter asserts that this sort of balancing fully aligns with the language of CAA section 111(d), which does not direct that sources are necessarily entitled to age-based variances under any particular circumstances. Rather, the provision *allows* states to “*take into consideration*” RULOF when establishing performance standards for particular sources. States must weigh these considerations against other factors—namely, health and environmental impacts—when determining whether to grant a variance.

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<sup>128</sup> As discussed in greater detail below, the commenter urges that the “fundamentally different” language that EPA proposes to include under the third variance condition (i.e., the “other factors” condition) apply to all conditions for receiving a variance under CAA section 111(d).

The commenter (2433-EDF et al) encourages EPA to extend this community-protection requirement to all variance requests, regardless which clause they fall under. As currently written, the proposed RULOF provisions requires that states “consider the potential health and environmental impacts and benefits of control to any community most affected by and vulnerable to impacts from the designated facility” whenever it calculates a less stringent standard for a source, regardless of the variance category. The commenter believes that this is an improvement from the status quo, but it is less protective than the condition that applies specifically to age-based variances, which *prohibits* a state from granting a less stringent standard for any source unless it can demonstrate that the increased emissions resulting from the variance “not result in negative impacts to the surrounding communities.” The commenter recommends that EPA include this requirement regardless of the variance clause the state is invoking when calculating a less stringent standard for any source.

*Third*, for any source receiving an age-based variance, the state must establish a federally enforceable retirement commitment in the plan. This will discourage unwarranted variance applications and will ensure that excess pollution resulting from variances will be of limited duration. However, the commenter (2433-EDF et al) urges EPA to improve this requirement in several regards. First, the proposal does not specify any timeframe within which a source receiving an aged-based variance must retire. The commenter requests that EPA clarify this to require that a source receiving a variance of this nature retire at the expiration of the amortization schedule that the source owner has used to demonstrate unreasonable compliance cost, subject to a reasonable capital recovery window and interest rate specified by EPA. Furthermore, the proposed regulations provide that “if a designated facility’s retirement date is imminent, the plan may apply a standard that reflects the designated facility’s business as usual.” The commenter notes that EPA does not define “imminent” in this context, leaving it susceptible to an inappropriately expansive definition in state plans. The commenter requests that EPA establish a clear definition that limits “imminent” retirements to those that are very near—no more than one to two years.

The commenter (2433-EDF et al) further urges EPA to drop the proposed “escape hatch” that would allow a source benefiting from a variance to abrogate its retirement commitment. Specifically, the commenter recommends that EPA delete this provision: “If an owner or operator of such a designated facility elects not to retire the designated facility as scheduled, the designated facility must achieve compliance with the standard listed in the Model Rule for the designated facility by the date otherwise required for the designated facility.”<sup>129</sup> The commenter contends that this is inherently contradictory: a retirement date cannot be “an enforceable commitment” if a source may “elect[] not to retire” by that date. Even if the source in question must meet the unmodified standards after that point, there is no provision for making up the extra pollution allowed during the variance period. Furthermore, the commenter adds that they believe that this provision will allow sources and states to adopt spurious retirement dates that they never intend to honor, effectively delaying compliance with the original standard.

In fact, the commenter (2433-EDF et al) asserts that if the “escape hatch” provision were to be used, it would undermine the equivalency determination EPA must make under the IRA. In this case, the commenter suggests that the state plan at issue might fall short of achieving the

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<sup>129</sup> Proposed 40 CFR 60.5365c(4).

emission reductions that would have resulted if the emission standards in the November 2021 proposed emission guidelines were fully implemented. Furthermore, the commenter states that CAA section 111(d) plans must be subject to “similar” procedures as CAA section 110 SIPs. The commenter notes that among those procedures is an anti-backsliding provision, CAA section 110(l), which prohibits revisions that interfere with the national ambient air quality standards (NAAQS) or other requirements of the Act. This suggests such backsliding, as in the case here of a plan that replaces a retirement with a provision that allows the source to continue to emit pollution, should not be allowed.

ii. Condition #2: Variances based on impossibility or technical infeasibility.

The commenter (2433-EDF et al) urges EPA to amend the second clause to remove “technological infeasibility . . . of installing necessary control equipment” as a potential basis for a variance.”<sup>130</sup> The commenter states that under the 1975 and 2019 regulation this clause was limited to situations of “physical impossibility.” The commenter expresses concern that “technical infeasibility” is a highly imprecise term that is susceptible to abuse and overapplication, and EPA has provided no definition or guidance on the term. There may, for example, be instances in which a source must undertake some small, additional, and cost-effective modification in order to install a control technology and on that account seek—inappropriately—a variance based on “technically infeasible.”

The commenter (2433-EDF et al) states that to the extent that a source truly is uniquely situated from a technical standpoint, the third variance clause already encompasses it with the “fundamental difference” limitation that we recommend apply to all three clauses (see below). The commenter suggests that it is not clear what other bases for technological infeasibility these clauses would not already cover, particularly since EPA has also already proposed to allow the application of alternative standards at certain facilities based on technical infeasibility.<sup>131</sup> Accordingly, the commenter urges EPA to remove “technical feasibility” as a basis for allowing variances, or at least to make clear that it too is subject to the requirement of fundamental difference. If the agency does retain this factor, the commenter requests that EPA provide much more specific guidance and limitations on its application.

iii. Condition #3: Limiting “other factors” to “fundamentally different factors.”

The commenter (2433-EDF et al) contends that under the 1975 and 2019 RULOF provisions, the non-specific “other factors” exemption in clause (3) is vulnerable to abuse by sources seeking to avoid otherwise applicable pollution control requirements. However, the commenter notes that the December 2022 supplemental proposal now inserts important limiting factors into the “other factors” exemption process. First, the “other factors” category now reads as follows: “other factors . . . that are fundamentally different from the factors considered in the determination of the best system of emission reduction in the emission guidelines.” The commenter states that “fundamentally different” means more than just “some difference.” Rather, the commenter

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<sup>130</sup> Proposed 40 CFR 60.5365c(a)(2).

<sup>131</sup> For example, the commenter states that the EPA has proposed to allow flaring of associated gas at oil wells if it is technically infeasible to route to a sales line, use onsite, use for another beneficial use, or reinject or inject the gas. 87 Fed. Reg. at 74780.

suggests that the source must be so different that it is not rational to expect it to achieve the same degree of emission limitation as other sources in the category or subcategory. The commenter supports the “fundamentally different” qualifier in that it will prevent a state from displacing EPA’s judgment regarding the emission limitation that reflects the BSER for a category or subcategory on minor and unexplained or unproven grounds.

The commenter (2433-EDF et al) states that EPA has employed this definition of “fundamentally different” for decades in the context of the Clean Water Act. There, EPA may grant a “fundamentally different factor” variance from national effluent limitations for a specific point source.<sup>132</sup> But that variance is only permissible in abnormal circumstances, such as when imposing the national effluent limitation would result in a removal cost “wholly out of proportion” with EPA’s estimated removal costs.<sup>133</sup> Thus, under one of the CAA’s companion statutes, a “minor difference” will not justify a “fundamentally different factor” variance. The commenter asserts that there is no reason to read EPA’s proposed language here any differently.

Furthermore, as noted above, the commenter (2433-EDF et al) urges EPA to extend the “fundamentally different” qualifier to all three variance clauses. Any variance is appropriate only if the emission guideline EPA did not already consider the factors at play in determining the emission limitation that reflects the “best system of emission reduction” for the relevant source category or subcategory. For example, the first clause permits variances based on unreasonable costs resulting from plant location. The commenter recommends that a state should have to demonstrate that compliance cost differences for the source seeking a variance are “fundamentally” different from the costs that are representative of other sources in the relevant category or subcategory. Likewise, under the second clause, to invoke “physical impossibility,” a state should have to demonstrate that a source’s physical configuration poses an obstacle so fundamental that the emission limitation cannot be met at all, or only at fundamentally (order of magnitude) higher cost compared to other members of the relevant category or subcategory.

The commenter (2433-EDF et al) suggests that EPA provide greater clarity in the regulatory text regarding the nature of “fundamental differences.” According to the preamble, a “fundamental difference” must relate to a particular factor that is relevant to EPA’s determination of the “best system” for a category or subcategory, on the one hand, and that same factor as applied to the specific facility seeking a variance. Yet the proposed rule’s regulatory text does not quite capture this: it refers to “other factors specific to the facility (or class of facilities) that are fundamentally different from the factors considered in the determination of the best system of emission reduction in the emission guidelines.” The commenter states that this text could be interpreted to allow states to grant variances based on extra-statutory factors that EPA did not and could not have considered in setting BSER, such as local political opposition to stringent regulations.

Instead, the commenter (2433-EDF et al) suggests that the provision should read along the following lines: “other factors considered by EPA in determining the best system of emission reductions which, when applied to the specific facility, are fundamentally different from EPA’s finding for the category or sub-category.” Thus, when EPA asks whether there are “other considerations” under which variances are appropriate,” those considerations themselves must

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<sup>132</sup> See 40 CFR pt. 125, subpart D.

<sup>133</sup> 40 CFR 125.31(b)(3)(i) (emphasis added).



be relevant to the statutory factors EPA considered in determining BSER, such as cost and degree of emissions reduction, even while the application of those factors to the facility in question result in fundamental differences.

c. Granting RULOF variances for source limitations that are more stringent than EPA's proposed guidelines.

Finally, the commenter (2433-EDF et al) supports EPA's interpretation of CAA section 111(d) as allowing EPA to approve a state plan with standards for a category, subcategory, or individual source that are *more* stringent than the emission limitations in EPA's guidelines.

Since 1975, the commenter (2433-EDF et al) states that the EPA has interpreted the statute to require state plans that are "*no less stringent* than the corresponding emission guideline(s)," <sup>134</sup> a formulation that clearly contemplates more stringent standards. According to the commenter, this squares with the CAA itself, which directs EPA to approve only those plans that are "satisfactory." <sup>135</sup> The commenter believes that the notion that EPA could reject as somehow less than "satisfactory" a state plan that not only achieved but exceeded the emission reductions required by the agency's guidelines would contradict the logic of the Supreme Court's holding in *Union Electric Company v. EPA*. <sup>136</sup> There, the commenter provides that the Court ruled that EPA may not reject a SIP under CAA section 110 of the Act on the grounds that the plan exceeds the minimum federal requirements. <sup>137</sup> As the Court explained, legislative history, along with the "structure and purpose" of the Act, confirm that SIPs must "meet the '*minimum* conditions' of the [provision]," but that "[b]eyond that, if a [s]tate makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it or lose a certain industry if attainment is not possible," EPA may not thereby reject the plan on the grounds that it is too stringent. <sup>138</sup>

As the court further explained, CAA section 116 of the Act specifically preserves state authority to adopt standards more protective than EPA's under this provision of the statute. Thus, the commenter notes that if EPA were permitted (or required) to reject SIPs as *overly* (as opposed to insufficiently) protective of health and the environment,

[it] would not only require the Administrator to expend considerable time and energy determining whether a state plan was precisely tailored to meet the federal standards, but would simultaneously require States desiring stricter standards to enact and enforce two sets of emission standards, one federally approved plan and one stricter state plan. We find no basis in the Amendments for visiting such wasteful burdens upon the States and the Administrator, and so we reject the argument of Amici. <sup>139</sup>

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<sup>134</sup> 40 CFR 60.24(c), 60.24a(c).

<sup>135</sup> 42 U.S.C. § 7411(d)(2)(A).

<sup>136</sup> 427 U.S. 246 (1976).

<sup>137</sup> Id. at 265.

<sup>138</sup> Id. at 264-65 (emphasis added).

<sup>139</sup> Id. at 264.

The commenter (2433-EDF et al) contends that all these principles apply equally to CAA section 111(d) plans as to CAA section 110 plans. Indeed, the commenter states that Congress explicitly modeled CAA section 111(d) on CAA section 110, directing the Administrator to “establish a procedure similar to that provided by section 7410 of this title”<sup>140</sup> by which a state submit plans achieving the federal emission reduction requirements for sources within their borders. Thus, for all the reasons described in *Union Electric*, the commenter believes that the EPA rightly concludes that it may not reject section 111(d) state plans that are more stringent than the federal emission guidelines.

Response II-19-31: Please see RULOF discussion in section XIII.C.3 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### ***19.3.4 Information Sources***

Comment: Commenter (2337-KDHE) asserts that there is no legitimate reason for EPA to restrict sources of information if sources are adequately documented according to established principles in scientific literature. The commenter contends that proposing a list of sources – and requiring EPA regional offices decide whether a source meets requirements - is contrary to the goal of cooperative federalism and has nothing to do with legitimacy, verifiability, or transparency.

Response II-19-32: The EPA has not finalized the provision referred to in this comment.

#### ***19.3.5 Low Producing Well Considerations***

Comment: Commenter (2337-KDHE) states that environmental justice (EJ) is an “other factor” in the context of RULOF. The commenter recommends that EPA waive compliance of proposed monitoring requirements for low production wells for EJ reasons, at least in the following counties: Barber, Chautauqua, Coffey, Finney, Grant, Greenwood, Haskell, Kearny, Ness, Rooks, Russell, Seward, Stafford, Stevens, Wilson, and Woodson.

The commenter (2337-KDHE) reports that of its total 105 counties, Kansas has 29 counties that currently have more than 1,000 producing oil and/or gas wells within their borders. Among these, there are 16 counties, found chiefly in the southwest and southeast parts of the state, which the 2020 U.S. Census shows to have at least one EJ demographic index at least five percent above the corresponding average U.S. value.<sup>141</sup> The commenter states that the demographic indices analyzed were persons less than five, persons greater than or equal to 65, percent people of color, percent limited English speaking households, less than high school education, and persons in poverty. The commenter notes, for example, Stevens County, which had 2,159 producing wells in 2021, shows limited English-speaking households 7.9 percent above the U.S.

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<sup>140</sup> 42 U.S.C. § 7411(d)(1).

<sup>141</sup> See <https://www.census.gov/quickfacts/>.

average (21.7%), and shows persons with less than high school education 15.0 percent above the U.S. average (11.1%). Moreover, the commenter reports that the 2020 average population density for these 16 counties is 10.3 persons per square mile, which is 89 percent below the national average (93.8 persons per square mile). The commenter states that in these rural counties the oil and gas industry is a primary economic mainstay, and that the closure of producing wells has serious negative impacts to surrounding communities.<sup>142</sup> The commenter provides that in this respect and combined with the certain knowledge that owners and operators of low producing wells cannot afford to comply with the proposed rule as written, the rule is not promoting EJ; on the contrary, the commenter believes that the rule would itself instead seriously impact many EJ communities.

Response II-19-33: The EPA has not finalized separate requirements for low production wells. However, the EPA has finalized standards for fugitive emissions that take into account the size of the well. See section X.A of the final rule preamble.

Comment: Commenter (2240-Rose Rock) recommends that EPA allow states more flexibility to develop specific requirements for existing sources without overburdening state resources. The commenter asserts that the proposed rule will vastly increase the resources required to manage and regulate existing sources without providing a means for additional funding. The commenter reposts that the Oklahoma Department of Environmental Quality (OK DEQ) has estimated that under the proposed rule, the number of oil and gas permitted facilities would go from approximately 10,000 to over 200,000. Most of these facilities are low producing and have low emissions.

Response II-19-34: The EPA does intend on working with tribes and states to develop plans tailored to the factors concerning the states. The plan development process, under which performance standards for existing sources are established within their jurisdiction and have the discretion to consider remaining useful life and other factors, is one that Congress established through the text and structure of CAA section 111(d). See discussions in section V.B.2.<sup>143</sup> and section V.B.3.<sup>144</sup> of the December 2022 Supplemental and section XIII of the final preamble and final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

The new standards will work hand-in-hand with new resources and programs in the Inflation Reduction Act, which will incentivize early implementation of innovative methane reduction technologies and support methane mitigation and monitoring activities. These efforts will achieve greater methane emissions reductions more quickly. For more information on the IRA, the Administration has created a guidebook that provides an overview of the clean energy, climate mitigation and resilience, agriculture, and conservation-related tax incentives and

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<sup>142</sup> See "Marginal Well Report (2016)" [https://iogcc.ok.gov/sites/g/files/gmc836/f/marginal\\_well\\_2016-final.pdf](https://iogcc.ok.gov/sites/g/files/gmc836/f/marginal_well_2016-final.pdf) found at <https://iogcc.ok.gov/publications>.

<sup>143</sup> 87 FR 74812.

<sup>144</sup> 87 FR 74816.

investment programs, including who is eligible to apply for funding and for what activities. See <https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/> .

Comment: Commenter (2283-Endeavor Energy) recommends that EPA take additional time to develop EGs that reflect the realities of older existing sources as required by the CAA. The commenter reports that because many older sites do not produce as much oil or gas, these new compliance obligations could very well alter the "remaining useful life" of the well and cause wells to be shut in or prematurely abandoned. The commenter states that this is the case for many producers and could have far-reaching impacts on domestic oil and gas production. The commenter expresses concern that the overly prescriptive and inflexible approach proposed by EPA does not properly reflect the CAA statutory requirement that directs EPA to ensure that its EGs permit the states to take remaining useful life and other factors in account-

Response II-19-35: Please see discussion in section XIII.C. of the final preamble regarding state's flexibilities in establishing standards in state plans.

Comment: Commenter (2201-WVHC) urges EPA to avoid any possibility that states could make categorical exclusions of small gas wells. The commenter believes that an attempt to provide state flexibility has the potential to create an enormous, dangerous loophole that makes the rule much less effective. The commenter reports that West Virginia has tens of thousands of small gas wells that are either abandoned and have no production that is collected and sold or have small production. A substantial fraction of these wells are leaking methane into the atmosphere. Collectively—and in some cases individually—the commenter reports that these legions of small wells are making a dramatic contribution to the problem of leaking methane.

Response II-19-36: Please see discussion in section XIII.C. of the final preamble regarding state's flexibilities in establishing standards in state plans.

Comment: Commenter (2434-Private Citizen) urges EPA to make the RULOF provisions very strict, so that it is rare for a state to be able to grant an exemption based on RULOF. Older or smaller gas wells often leak quite a large amount of methane and VOCs, and exempting these older or smaller wells due to limited Remaining Useful Life would still harm human health. Companies need to be responsible for wells that they own, and make sure they don't hurt children and seniors even if the well is not being used. They need to be capped and sealed, and tested to be sure the seal is working properly and no methane is leaking.

Response II-19-37: Please see RULOF discussion in section XIII.C.3 of the final preamble.

## **19.4 Considerations of Impacted Communities**

### ***19.4.1 Support for Meaningful Engagement***

Comment: Several commenters (2177-Ute, 2249-NACAA, 2296-NMED, 2303-NTAA, 2447-CleanAir) express support for meaningful engagement. Some of the commenters specifically request that EPA provide relevant guidance and training material and allow for new and existing technology. Examples of some of the comments provided are presented in the following

paragraphs. Commenter (2177-Ute) agrees that states must coordinate with tribes that are within the borders of the state, and coordinate with neighboring tribes in the same manner as neighboring states. The commenter asserts that it is important to consider that methane is not a regional pollutant, and there are no NAAQS in place. The commenter states that reduction, or increases in, methane would not have a significant impact on neighboring states or tribes. The commenter states that there could be significant impact if a state or tribal plan caused operators to install combustion equipment (generators, air compressors, etc.) to comply with proposed regulations, and this equipment caused increases in criteria pollutant and ozone precursors, which caused or contributed to NAAQS violations.

Commenter (2447-CleanAir) requests that EPA provide guidance on undertaking robust, inclusive and meaningful outreach and engagement with affected communities and tribes when developing state plans to establish methane reduction standards for existing sources as prescribed under section 111 (d) of the CAA, while also intervening when states that do not submit plans for EPA review and do not have existing and/or refuse to develop new programs that are as effective as the presumptive standards.

Commenter (2303-NTAA) requests that EPA provide assistance and resources, including funding, to Tribes, if they want it, to develop and implement plans and/or permitting programs. Additionally, with respect to Tribes that have standards or requirements in place prior to finalizing this rulemaking, the commenter requests that EPA continue its work with them to promote ease of implementation and consistency with this rulemaking.

Commenter (2249-NACAA) supports robust public engagement, especially with underserved and disproportionately impacted communities, and requests that EPA provide specific criteria and assist implementing agencies by providing resources, guidance, training, and other support.

The commenter (2249-NACAA) notes that EPA's December 2022 supplemental proposal calls for a "robust and meaningful public participation process" with provisions "to require states to identify and conduct meaningful engagement with underserved and overburdened communities as they develop state plans." Further, the commenter notes that this outreach and engagement would include sharing information with all stakeholders throughout the plan development process and seeking their input before a plan is adopted and submitted to EPA. This commenter reports that this aligns with their commitment to environmental justice.<sup>145</sup> Should EPA mandate more robust public engagement and make it a federal requirement for plan approval, the commenter asserts that EPA must be more specific about what will be approvable and be up-front about providing guidance to states that identifies communication objectives as well as outlining the process and methods of engagement.

The commenter (2249-NACAA) notes that some states have conducted robust analyses and implemented sophisticated programs, but not all agencies have done this work. Where agencies have completed their own analyses and developed tools and programs in consultation with their local communities and advisory groups, the commenter recommends that EPA allow these to

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<sup>145</sup> NACAA's "Mission & Values" and "Statement & Direction for Racial Justice" are available at [http://www.4cleanair.org/sites/default/files/Documents/NACAAMissionValuesGoalsandRacialJusticeStatement-10\\_19\\_2020-noQ.pdf](http://www.4cleanair.org/sites/default/files/Documents/NACAAMissionValuesGoalsandRacialJusticeStatement-10_19_2020-noQ.pdf).

serve compliance needs, rather than simply mandating national adoption of federal tools. Some of the commenter's members are at the cutting edge of achieving meaningful involvement of vulnerable communities in agency decision-making, with programs that have far longer track records and that are more robust than anything at the federal level. The commenter recommends that EPA draw from and benefit from their experience. State and local programs with deep experience in advancing clean air protection with and for vulnerable communities have learned that these efforts are very time- and resource-intensive, not just for agencies but for the communities themselves. Given the tremendous variety of communities, their needs, and their constraints, the commenter urges EPA to set expectations realistically and allow for the flexibility to truly meet the unique needs of these communities, as well as to reflect the economics and demographics of individual states.

Commenter (2296-NMED) supports EPA's meaningful engagement and reasonable notice requirements. The commenter recommends that EPA permit both new and traditional communication technologies to qualify as meaningful public engagement. The commenter believes that requiring states to share information and solicit input from stakeholders at critical junctures during plan development will ensure communities have abundant opportunities to participate in the plan development process.

The commenter (2296-NMED) asserts that the proposal to give the reasonable notice requirement additional and separate meaning from "public hearing" will ensure that the public has reasonable notice of relevant information, as well as the opportunity to participate in the state plan development. The commenter contends that requiring states to provide this opportunity to stakeholders directly addresses a major issue of environmental inequity: the ability for stakeholders to participate in the process that determines impacts and risks to their health and environment. According to the commenter, requiring the opportunity for stakeholders to participate will necessitate that a state not only holds a public hearing but guarantees all interested stakeholders have the chance to participate in the development process.

The commenter (2296-NMED) reports that modern communications technology has made it much easier for states to effectively communicate with various communities and stakeholders. While there may be barriers involving accessibility to these technologies that should be considered, the commenter recommends that these technologies should still be utilized during the meaningful engagement process. These technologies include video conferencing, social media, and smart phone apps. The commenter states that video conferencing can be an effective planning tool that allows for planners and state officials to communicate with community members and other stakeholders.

Commenter (2315-NY DEC) recommends the development of a plan that identifies communication objectives, as well as outlines the process and methods of engagement. The commenter has a history of community engagement with respect to air quality concerns and therefore recommends that EPA look to some of their previous work on the Peace Bridge Air Study,<sup>146</sup> Albany's South End Neighborhood Air Quality Initiative,<sup>147</sup> Tonawanda Community

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<sup>146</sup> <https://www.dec.ny.gov/chemical/83984.html>.

<sup>147</sup> <https://www.dec.ny.gov/chemical/108978.html>.

Air Quality Study,<sup>148</sup> Brookhaven Air Quality Improvement Actions,<sup>149</sup> Dunn Landfill<sup>150</sup> and their Community Air Screen Program.<sup>151</sup>

Response II-19-38: Please see the discussion on the topic of meaningful engagement in section XIII.C.6 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### ***19.4.2 Meaningful Engagement Criteria are Unclear and Burdensome***

Comment: Several commenters (2157-TDEC, 2186-MDNR, 2218-TCEQ, 2222-WDNR, 2237-ICND, 2258-MSD, 2288-NDDEQ, 2310-MDEQ, 2319-ADEM, 2322-ADEE, 2323-ADEQ, 2330-KDAQ, 2393-OSEE) express concern with the lack of clarity surrounding meaningful engagement criteria. The commenters request that EPA provide clear definitions and evaluation criteria that EPA will use to determine if sufficient meaningful engagement was completed. In general, the commenters recommend that the meaningful engagement requirements be removed. Some commenters question the need for additional requirements where requirements are included in existing state programs. The commenters believe additional requirements are burdensome and unnecessary. Examples of some of the comments provided are presented in the following paragraphs.

Commenters (2237-ICND, 2288-NDDEQ) note that North Dakota has procedures to address meaningful engagement, including Title VI and Environmental Justice. The commenters contend that EPA's rule as proposed includes vague requirements of "development of public participation strategies" and "early outreach, sharing information, and soliciting input." The commenters believe that these requirements all appear to be already met through the established public hearing requirements along with the Title VI and Environmental Justice programs. By including meaningful engagement as a requirement of the state plan, and as such as part of the "minimum criteria for completeness" but not defining explicitly how it must be fulfilled, the commenters assert that EPA also hides the criteria by which it will judge the plans and plan revisions. The commenters view the requirements around "meaningful engagement" to be either too vague to confidently fulfill under the threat of EPA disapproval, or duplicative of the already established and widely accepted public hearing process.

Commenter (2222-WDNR) requests that EPA provide clear evaluation criteria that EPA will use to determine if sufficient meaningful engagement was done during the state plan development process and how EPA will consider this meaningful engagement criteria when assessing approvability of state plans. The commenter recommends that EPA provide states general criteria to identify the meaningful engagement process necessary given the state-specific factors covered

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<sup>148</sup> <https://www.dec.ny.gov/chemical/59464.html>.

<sup>149</sup> <https://www.dec.ny.gov/chemical/111038.html>.

<sup>150</sup> <https://www.dec.ny.gov/chemical/117071.html>.

<sup>151</sup> <https://www.dec.ny.gov/chemical/81629.htm>.

by the state plan. The commenter suggests that these factors could include the total emissions reductions expected by the rule and geographic proximity of large emission sources.

The commenter (2222-WDNR) notes that states seeking to adopt EPA's model rule language have little flexibility to modify regulatory requirements in response to public input. The commenter recommends that EPA take responsibility to ensure its model rule and federal plan process meets the stated meaningful engagement criteria before finalizing model rule language and allow states to reference EPA's process when adopting EPA language.

Commenter (2186-MDNR) requests that EPA provide clarity on what constitutes meaningful engagement with the target populations and the specific actions necessary during the state development process to meet this new requirement. The commenter requests clarification on the criteria used to evaluate meaningful engagement in state plans. Specific questions include:

*Identifying overburdened areas:*

1. What is the definition of an overburdened or underserved area?
2. What are the process and data sets states need to use to identify these areas?
3. What is the process for selecting the extent of such areas?
  - a. Should these areas be defined as a small neighborhood or multi-block area, is it a census tract, is it a city, is it a township, is it a county, is it an entire metropolitan statistical area, could it be an entire state or multi-state region?
4. How close to an affected facility does the overburdened area need to be located to be considered impacted by the action?

*Meaningful engagement requirements for overburdened areas:*

1. What are the minimum requirements for states to ensure they are complying with the new meaningful engagement provisions?
  - a. Are states required to hold a meeting in every identified area?
  - b. Are virtual meetings allowed, or do they need to be in-person?
  - c. Does one meeting satisfy the requirement, or must states hold numerous public engagement meetings?
  - d. Are newspaper ads or mail outs required?
  - e. At what stage in the plan development process do the new engagement practices need to occur: e.g., before any work is done, before the public comment period, during the public comment period, after the public comment period, all of these?

The commenter (2186-MDNR) reports that the state Air Program strives to provide meaningful public engagement in all state plans it develops, meeting and usually exceeding all required public notice and comment requirements. However, when EPA establishes new administrative or



procedural requirements that states must follow, the commenter asserts that clarity and certainty is essential. The commenter contends that the proposed rule does not provide this, and states will struggle trying to ensure they are meeting these requirements if the final rule does not clearly answer all these questions.

Additionally, the commenter (2186-MDNR) notes that this new meaningful engagement requirement requires state resources. The commenter contends that federal grants or other new funding mechanisms will be necessary to assist states with these new requirements. The resources needed will vary depending on some of the answers to the questions listed above by the commenter. The commenter reports that businesses and governments across the country are struggling to recruit and retain qualified staff members to carry out essential duties. The commenter urges EPA to recognize this reality and adequately address it as it considers the new requirements it promulgates.

Commenter (2330-KDAQ) requests that EPA provide clarity on what it means to perform meaningful engagement. The commenter contends that it is inappropriate to require additional meaningful engagement without clearly stating expectations. Further, the commenter asserts that EPA's intention "to propose similar meaningful engagement provisions to this provision under the implementing regulations in a separate upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d)." is a piecemeal approach that is not sufficient to allow meaningful comment on this proposed rulemaking. The commenter recommends that EPA re-propose the complete rulemaking in its entirety and with full requirements so that the impacts can be evaluated.

The commenter (2330-KDAQ) states that EPA requesting public comment on broad topics of meaningful engagement does not allow states to evaluate the costs or implications of actual requirements. The commenter believes that this is more appropriate for an Advanced Notice of Proposed Rulemaking and not a proposed rule.

The commenter (2330-KDAQ) supports the flexibility of requesting alternate meaningful engagement procedures that in fact provide for adequate notice to and meaningful engagement of the public. The commenter already provides regulatory notice to the public throughout the process of any regulatory change through its State Legislature and certain permitting actions. The commenter states that this is especially important where EPA is expanding meaningful engagement procedures in a way that has not been previously required.

Commenter (2323-ADEQ) expresses concern that the vagueness in EPA's approach to "meaningful engagement" could lead to confusion and inconsistent results. The commenter requests that EPA either provide additional structure regarding this requirement or remove it from EPA's proposed completeness criteria for this EG.

The commenter (2323-ADEQ) agrees that it is important to engage the pertinent stakeholders in the development of state plans (and state implementation plans) that will impact them. However, the commenter notes that the proposed rule does not make it clear what steps are necessary for this state plan submittal to be meet the completeness criteria. While the draft rule seems to be written broadly to account for a wide range of circumstances nationwide, the commenter believes

that it leaves the meaning subject to interpretation. Generally, the commenter urges EPA to provide flexibility for states to allow them to address their local needs and conditions. However, the commenter expresses concern that the vagueness of these proposed requirements could lead to unnecessary level of conflict regarding their interpretation as to what is satisfactory for a completeness determination.

The commenter (2323-ADEQ) notes that while the rule provides factors that must be considered by the state, it is unclear how EPA will assess the adequacy of strategies to address these barriers to participation. Compared to the current SIP requirements in 40 CFR Part 51, Subpart F, which provides clear directions for states in their SIP development process, the commenter believes that the proposed rule's approach is rather nebulous. According to the commenter, the vague definition of meaningful engagement and EPA's ability to find a plan incomplete or disapprove if EPA determines the engagement to not meet that vague definition, could lead to a scenario where state plans are disapproved because EPA disagrees with the outreach approach selected by the state, intruding upon the outreach and plan development process that has traditionally been the states' expertise and knowledge of their own state.

Therefore, the commenter (2323-ADEQ) requests that EPA either more clearly define what actions are necessary to satisfy the meaningful engagement requirement or de-couple the meaningful engagement from the completeness determination. The commenter believes that providing greater clarity for these requirements will help states focus their outreach efforts in the most effective manner, based on their unique knowledge of issues within each state, while preserving scarce agency resources.

Commenter (2310-MDEQ) requests that EPA provide more specificity regarding meaningful public engagement because the proposed definition is subjective and open to interpretation, which may differ between states and EPA. The commenter contends that approvability of a state plan cannot be decided on subjective criteria. In addition, the commenter requests that EPA engage meaningfully with the oil and gas producing states.

Commenter (2258-MSD) recommends that EPA eliminate the new requirements for meaningful engagement. The commenter notes that each state has mandated procedures that must be followed when adopting new regulations, including public comment and public hearings. The commenter notes that EPA's existing regulations at 40 CFR 60.23a outline the basic requirements for state plan adoption while respecting individual state differences. The commenter contends that the requirements in 40 CFR 60.23a are adequate.

Commenter (2218-TCEQ) asserts that EPA's proposed meaningful engagement requirements are burdensome and unnecessary. They explain that states are already required to provide public notice and do so through a variety of mechanisms that have been previously approved by the EPA. The commenter recommends that the proposed meaningful engagement requirements and modification of the EPA's interpretation of "reasonable notice" be excluded. However, if the EPA moves forward to finalize the requirements, the commenter urges EPA to provide states with specific criteria for what is required and what would be approvable in a state plan regarding these requirements. To ensure states have adequate opportunity to provide feedback, the commenter recommends that EPA propose and take public comments on a clear definition of

pertinent stakeholders and guidance on how to identify pertinent stakeholders and specific requirements for “reasonable notice” for purposes of the state plan. The commenter recommends that the definition and guidance be finalized with the rule and at least three years before a state plan is due. If the EPA requires reasonable notice and meaningful engagement in state plans, the commenter recommends that EPA clearly describe what would be approvable while allowing states flexibility to meet the requirements. In addition, the commenter states that EPA must propose and take public comment on the requirements before finalizing them.

The commenter (2218-TCEQ) notes that completeness criteria for state plans is found at 40 CFR 40 CFR 60.27a(g) and includes public participation requirements that require states to conduct at least one public hearing after reasonable notice. The commenter states that these criteria are and have been adequate to ensure stakeholder and public participation in the development of the state plan. Therefore, the commenter believes they should not be changed for this plan. Additionally, they suggest that existing public notice requirements which do not address meaningful engagement requirements are appropriate and already adequately provide for public engagement with state actions to develop state plans. The commenter states that it is not evident that adding ill-defined engagement provisions would substantively improve the state plan development process; however, adding such provisions would significantly burden states with new costs associated with attempting to interpret and implement the provisions with no clear criteria for EPA approval.

The commenter (2218-TCEQ) reports that they meet state and federal notice public participation requirements by making materials publicly available, accepting public comments, and publishing public notices of public meetings and rule and state plan revisions. The commenter makes the public aware of proposals using a variety of venues including its website, various listservs, newspapers, the Texas Register, and social media outlets. In addition, formal public comments can be made electronically, at public hearings, via U.S. Mail or fax, or hand delivery. The commenter reports that they also amended public notice and participation requirements in 30 Texas Administrative Code (TAC) Chapters 39 and 55 in 2021 and developed agency public participation and language access plans to ensure meaningful public participation for new actions; changes to agency policies, procedures, general permits, and regulations that may affect the public; and for activities that are likely to have significant interest from the public and the regulated communities. New requirements include alternative language notices for public meetings, interpretation services at public meetings, evaluation of the need to provide responses to comments in alternative languages, the provision of plain-language summaries for proposed projects as well as the translation and posting of the summaries on the commission’s website when alternative language publication is required. The commenter provides that EPA has found that their public notice and participation measures to be adequate and offers no defensible reason why public notice and participation opportunities should be changed for this state plan.

While the proposed meaningful engagement requirements are not clearly described, the commenter (2218-TCEQ) believes that resources needed to fulfill them will be significant and burdensome to states. According to the commenter, fulfilling meaningful engagement requirements will cause states to incur costs associated with identifying and contacting stakeholders, renting of rooms or spaces for multiple public meetings, travel, and associated staff time. The commenter states that it is also overly burdensome for the EPA to require states to

conduct meaningful engagement when adopting the model rule since the EPA already conducted meaningful engagement when setting the standards. The commenter notes that Texas is a large state and based on the December 2022 proposed supplemental rulemaking, there will be a vast number of affected facilities located throughout the state. Further, the commenter believes that the proposed 18 months to submit state plans is insufficient with the additional time needed to meet these requirements.

Commenter (2157-TDEC) states that meaningful engagement should not be required for states that adopt EPA's standard with no exceptions for RUOF as it is assumed that EPA has already conducted meaningful engagement prior to issuing its own guidelines. Therefore, the commenter believes that additional engagement efforts by states for the same plan are unnecessarily duplicative and superfluous. If the EPA proceeds with this requirement, the commenter requests EPA clarify what a state will be expected to do with the information learned during meaningful engagement regarding a state plan that adopts EPA's requirements verbatim.

The commenter (2157-TDEC) reports that Tennessee's Uniform Administrative Procedures Act, procedures established by the Tennessee Governor's Office, and EPA rules and procedures require all state plans to include regulatory provisions for the: 1) review of pre-draft rule by EPA's regional office, 2) review and approval by the Tennessee Governor's Office, 3) preview of the draft rule to the Tennessee Air Pollution Control Board, 4) posting of proposed rule on Secretary of State's administrative register website at least 45 days prior to public hearing, 5) an EPA-mandated 30-day public notice, 6) an EPA 30-day pre-hearing review, 7) a public hearing conducted by TDEC, 8) TDEC's review of and response to public comments, 9) approval by Tennessee Air Pollution Control Board, 10) review of adopted rule by Governor's Office, 11) approval of adopted rule by Attorney General's Office, 12) filing of final rule with Secretary of State's Office, 13) a 120-day post-filing period for the rule to become effective, and 14) review of final rule by General Assembly's Joint Government Operations Committee. The commenter reports that the process will take up almost all the 18-month regulatory timeframe for submitting a plan to EPA for approval and cannot be initiated until the Division of Air Pollution Control has developed a draft state plan<sup>152</sup>. The commenter contends that EPA's shortened timeframe to prepare state plans makes the additional "meaningful engagement" required by the December 2022 proposal nearly impossible. The commenter urges EPA to consider whether plans completed in 18 months or meaningful engagement is the priority of the agency.

Commenter (2322-ADEE) believes that the meaningful engagement requirements are burdensome and may be difficult for states to achieve due to the increased amount of stakeholders. The commenter questions why state plans would need to demonstrate additional "meaningful engagement" outreach efforts, when EPA has deemed the proposed rule to have inconsequential effects on communities that are the focus of the executive order.

The commenter (2322-ADEE) notes that the December 2022 supplemental proposal removes the 3-ton per year threshold triggering requirements for "wellhead only sites," and many more communities and stakeholders would need to be included in state outreach than the original

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<sup>152</sup> Because this rule has the potential to substantially add to our workload, the commenter states that Tennessee will also need to consider whether other rule changes are necessary to cover the increased workload with new or increased fees.

proposal, which already included a vast number of stakeholders. The commenter states that the varying degrees of interest level, knowledge, and economic dependence on regulated sources that spans this diverse group of stakeholders will require state regulators to engage in intense targeted framing and explication of highly technical information. The commenter explains that it will not be a one-size outreach effort, and to produce fact sheets, presentations, and hold meetings on this scale will require months for states to prepare. The commenter contends that several more months will be necessary to roll out to the public in “meaningful engagement.” The commenter adds that the process is not intended to be a one-way street when engaging with stakeholders, and collaboration requires a public information and education period, a period to allow for presentation of stakeholder concerns, a period of time for regulator consideration and response to those concerns, and in many cases, further explanation and rationale developed and presented to support regulator decisions where stakeholders are not satisfied with initial responses. They further add that a state could expect this process to stretch out from eight to twelve months prior to beginning administrative procedures for rulemaking and SIP proposal, which themselves take an additional twelve to eighteen months to complete.

The commenter (2322-ADEE) contend that the rushed timeline EPA proposed leaves them with the following choices:

- a) forego submitting a plan and decide whether to take delegation of a federal plan;
- b) submit a plan based on EPA’s BSER without the ability to consider remaining useful life and other factors as allowed under the CAA or provide adequate meaningful engagement; or
- c) miss the deadline for submittal by performing its due diligence in engagement and technical analysis prior to adopting a plan.

The commenter (2322-ADEE) believes that the first and second options create an illusory collaborative environment, in which interested parties who present their concerns to state regulators will feel disenfranchised, as there will be little room for change once outreach begins. According to the commenter, this has a real possibility of degrading the community-regulator relationship. The commenter believes that EPA’s efforts to include all relevant stakeholders in information sharing and decision-making may cause more harm than good in this instance. Lastly, the commenter states that the third option results in wasted effort as missing the deadline would trigger a requirement for EPA to develop and implement a federal plan.

Commenter (2393-OSEE) requests that EPA re-assess the meaningful engagement requirements. The commenter supports robust public participation in state rulemaking efforts and provides that it already has existing mechanisms in place. The commenter reports that the state conducts public participation processes in accordance with the law. The commenter’s current method of notifying its citizens of hearings and other opportunities for public comment is through its website and through a dedicated listserv using GovDelivery. The commenter believes that the burden on the state to reach out to nearly every community across the state in some individual way and list the pertinent stakeholders in its state plan would waste valuable resources and staff

time and only delay actual implementation of the provisions of the emissions guidelines by delaying the state's ability to create a CAA section 111(d) plan.

In addition, the commenter (2393-OSEE) asserts that many states will be either using EPA's model rule or justifying equivalency of state rules that are already in place. The commenter believes that it is entirely possible that a state plan using the EPA-prescribed BSER will, during the meaningful engagement period, receive comments from the community that the state has not gone far enough in its plan. The commenter believes that this creates a logistical and regulatory conundrum since, theoretically, EPA's rulemaking should be presumptively approvable. Furthermore, they add that some states cannot be more stringent than federal rules. The commenter reports that other states, like Oklahoma, are required to meet additional statutory burdens when promulgating rules more stringent than corresponding federal rules. In either case, the result is often that the state requirements remain equivalent to the federal requirements. Therefore, the commenter states that "meaningful engagement," as proposed by EPA and when taken to its logical conclusion, sets up states and the public for confusion and frustration due to a potential disconnect between the perceived outcomes. Thus, the commenter asserts that EPA's concept of meaningful engagement is more appropriate on the federal level before EPA sets the regulatory baseline.

The commenter (2393-OSEE) reports that this same idea is borne out by comments made at EPA's "Pre-proposal outreach-Meaningful Engagement Discussion with Communities" held on July 26, 2022 (Docket Document ID #EPA-HQ-OAR-2021-0317-1526). The very first commenter stated that "meaningful engagement should start with an expectation that through their feedback, stakeholders will have the ability to change the outcome." The commenter went on to say that "there needs to be a process created where community members have a sense that their comments will have an effect on the final outcome." Another commenter similarly stated, "if engagement has no impact, people do not see the point in participating in the process." Additional similar ideas and concerns can be found throughout the Question-and-Answer document. When asked at what point in the regulatory process should engagement begin, one commenter said "as soon as ideation turns to staff consideration. After the feasibility is considered, it is already too late to begin attempting engagement." By this commenter's standards, by the time the state is trying to implement EPA's EGs into state rules and a state plan, it is much too late for meaningful engagement.

The commenter (2393-OSEE) acknowledges that state plans that incorporate RULOF in their decision-making is one place where meaningful engagement truly has meaning. The commenter states that when RULOF is taken into consideration for a facility, the facility may no longer be strictly following the model rule requirements but rather be granted alternate requirements. In these scenarios, the commenter recommends that the public should have an opportunity to review and comment if they object to the RULOF decisions made by the state. This allows the public to potentially affect a change in what the state was proposing (i.e., meaningful engagement). The state will also have a defined audience for its meaningful engagement as it would be appropriate to engage the communities nearby the RULOF facilities.

Commenter (2319-ADEM) asserts that additional meaningful engagement requirements are redundant in many cases. The commenter notes that EPA has already required states to consider disadvantaged communities when developing permits/rules in these areas.

Additionally, the commenter (2319-ADEM) asserts that most states do not have the adequate resources that would be required to conduct outreach to the extent that this proposal would require. The commenter states that depending on the type of industry for which a rule or plan is being developed, outreach of this type could be extremely resource-intensive and nearly impossible to ensure that all affected communities are directly contacted. For example, the commenter points out that there are gas and oil well heads located throughout many states. The commenter contends that to ensure that each community located near one of the well heads are directly contacted would undoubtedly exceed the financial and physical resources of most of these states. The commenter believes that notification in prominent and regional newspapers and similar publications is the only practical way to provide reasonable, cost-effective, and efficient outreach in these areas.

Response II-19-39: Please see the discussion on the topic of meaningful engagement in section XIII.C.6 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

Comment: Commenter (2393-OOSEE) notes a typographical error in the proposed language of 40 CFR 60.5363c(a)(6), which currently reads:

(5) Certification and evidence of meaningful engagement on such plan or plan revisions as specified in §60.5365c, including a list of identified pertinent stakeholders and a summary of the engagement conducted, a summary of stakeholder input received, and a description of any action or changes made as a result of the engagement.

The commenter (2393-OOSEE) believes that the reference to 40 CFR 60.5365c should instead be 40 CFR 60.5366c for meaningful engagement. Furthermore, the commenter adds that Table 2 and Table 4 are currently fully titled “Table 2 to Subpart OOOOb” and “Table 4 to Subpart OOOOb.” The commenter requests that EPA update the names of the tables to reflect they are part of EG OOOOc.

Response II-19-40: Please see the discussion on the topic of meaningful engagement in section XIII.C.6 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

### ***19.4.3 Affected Community Definition***

Comment: Several commenters (2202-TXOGA, 2218-TCEQ, 2237-ICND, 2288-NDDEQ, 2343-IPI NYU) request that EPA provide guidance and definitions of pertinent stakeholder definition. In general, the commenters assert that EPA's language is unclear. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (2218-TCEQ) believes that the proposed definition of pertinent stakeholders at 40 CFR 60.5366c(b) is not adequate for states to identify individuals or groups with whom meaningful engagement should be conducted for purposes of a state plan. The vagueness of the proposal may increase the likelihood of legal challenges to state plans or state plan disapproval because the EPA's interpretation of the requirements is not clear. The commenter contends that EPA must propose specific criteria that states may use to identify stakeholders as "most" affected as well as acceptable methods for states to use to make such a determination before meaningful engagement requirements are finalized. As proposed, the commenter states it is not clear how states would identify pertinent stakeholders, what criteria the EPA would use to determine whether pertinent stakeholders identified by states are appropriate, or that the criteria would not change in the future. The commenter asserts that states, not the EPA, are in the best position to identify pertinent stakeholders for their plans.

Commenters (2237-ICND, 2288-NDDEQ) note that "pertinent stakeholders" "include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision". The commenters believe that the current "pertinent stakeholder" language inclusion of the phrase "but are not limited to" is over-generalized. While it is appropriate that entities most affected/vulnerable to the impacts should be involved, the commenters believe that the language is too broad.

The commenters (2237-ICND, 2288-NDDEQ) contend that it would make sense that a pertinent stakeholder should at least be within the political boundary that the plan or plan revision applies, however proximity is not addressed. As wind-borne pollutants ignore such political boundaries, the commenter questions whether the State of Minnesota is a "pertinent stakeholder", being predominantly downwind of North Dakota. In the same manner the commenter questions whether the State of Montana, with multiple oil and gas fields straddling the state border with North Dakota, and whether Canada with similar fields on North Dakota's international northern border are "pertinent stakeholders".

Commenter (2202-TXOGA) recommends that EPA identify "communities most affected by and vulnerable to the impacts from the designated considered in a state plan for RULOF provisions." The commenter notes that EPA expresses an expectation that "these communities will be identified by the state as pertinent stakeholders under the proposed meaningful engagement requirements" which suggests that EPA has something in the nature of geographical proximity in mind. But where the designated pollutant at issue is a GHG, and the "impacts" from the emissions of that GHG are identified as stemming from the global phenomenon of anthropogenic climate change, the commenter believes that "communities most affected by and vulnerable to" any given designated facility would not necessarily be people living in close proximity but rather



people living in different locales throughout the country (and throughout the world). The commenter believes that identifying stakeholders using geographic criteria is not reasonable.

Commenter (2343-NYU-School of Law) recommends that EPA provide guidance on identifying affected communities, and vulnerable populations. The commenter suggests that communities be identified by first determining which pollutants would be more prevalent under the less stringent standard – and by how much. Then, they suggest that states identify the relevant affected communities for each of these pollutants in light of the pollutant’s media, exposure pathways, and exposure factors related to human behaviors. The commenter notes that affected communities may include not only the individuals who live within the areas where people are exposed, but also anyone who works or recreates there.

The commenter (2343-NYU-School of Law) recommends that EPA assist states by providing information on which pollutants would generally be expected to increase because of less stringent standards and information about their typical spatial distributions, exposure pathways, and exposure factors. It would be the responsibility of states to apply this information at the facility level based on site-specific considerations. At a specific facility, the commenter believes that it could be possible to analyze how wind patterns would shape the distribution of air pollutants under a less stringent standard.<sup>153</sup>

In short, to analyze exactly which communities would be affected by a less stringent standard, the commenter (2343-NYU-School of Law) states that it is necessary to think through which pollutants will increase and how the physical properties of those pollutants will translate into increased doses for individuals in specific areas. If states attempted to identify affected communities by selecting inappropriate (e.g., too large) geographic units, the commenter believes that it would create an inaccurate picture of whose health might be impacted by adopting a less stringent standard. They add that the same would be true if a state did not consider which communities live downwind of an air pollutant.

The commenter (2343-NYU-School of Law) notes that neither the December 2022 supplemental proposal nor the proposed regulatory text provides authoritative guidance on how states should identify, among all affected communities, the subset of people who are particularly vulnerable. Instead, the December 2022 supplemental proposal notes generally that “increased vulnerability of communities may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities.”

The commenter (2343-NYU-School of Law) recommends that EPA provide additional direction on identifying vulnerable communities so that states can more accurately assess how adopting less stringent standards for specific facilities would affect these groups. The commenter contends that increasing the accuracy of state assessments would improve the quality of decision-making and prevent harm to vulnerable communities that might have been obscured by flawed or incomplete analyses. Additionally, the commenter believes that more guidance from EPA on identifying vulnerable communities would help standardize states’ analyses, which would allow

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<sup>153</sup> See Revesz & Yi, *supra* note 41, at 86.

EPA to more consistently evaluate requests to adopt less stringent standards and thus promote regulatory certainty for states.

The commenter (2343-NYU-School of Law) reports that there are multiple types of guidance that EPA could offer states in the final rule about how to identify vulnerable communities among the affected communities. The commenters suggests that the EPA might enumerate minimum considerations relevant for identifying vulnerable groups. They add that these considerations might include any factors that dictate a community's cumulative dose of a pollutant, such as proximity to other sources of emissions and shared behavior (e.g., occupation). Separately, the commenter notes that a community may be vulnerable to a pollutant, not because of other exposures, but because of other factors that cause it to suffer worse health harms than others would experience at the same dose. These susceptibility factors include pre-existing disease, age, access to medical care, stress, diet, and exposure to similarly acting toxins.

Additionally, because states may face data constraints when identifying vulnerable communities, the commenter (2343-NYU-School of Law) recommends that EPA help states by including certain data and resources in the final rule. For example, for each pollutant that is relevant in this context, the commenter suggests that EPA indicate which communities have historically been most vulnerable. Or, the commenter suggests that the EPA might point states to resources that would help them estimate cumulative doses and susceptibility factors for each pollutant. The commenter recommends that EPA advise whether there is any overlap between the factors that would make a community vulnerable to increased pollution from a less stringent standard at a particular facility and the factors that cause a community to be "disadvantaged" (and thus prioritized for Justice40 investments) according to the Council on Environmental Quality's recent Climate and Economic Justice Screening Tool. Similarly, the commenter suggests that EPA examine whether any data available through EPA's EJ Screen tool (e.g., ozone or air toxics cancer risk) may assist states in identifying communities that would be vulnerable to increased pollution from application of a less stringent standard at a facility.

Response II-19-41: Please see the discussion on the topic of meaningful engagement in section XIII.C.6 of the final preamble.

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052. The final Subpart Ba is published at 88 FR 80480 (November 17, 2023).

#### ***19.4.4 Consultation Between EPA and State, Tribes, and Local Air Agencies***

Comment: Several commenters (2220-WDEQ, 2225-WESTAR, 2241-UDNR, 2296-NMED, 2403-PAO) request that EPA engage with oil and gas-producing states, Tribes, and local air agencies that will be affected by this rule. Some commenters identify specific agencies and highlight the need for continued engagement. Specific comments provided are presented in the following paragraphs.

Commenter (2241-UDNR) requests that EPA continue to coordinate with the State's County Resource Management Plans (RMPs), particularly Utah's top natural gas producing counties of Uintah, Carbon, Duchesne, and San Juan. Further, the commenter adds that EPA ensure that current and future actions taken in furtherance of the proposed rule remain consistent with said plans to the maximum extent possible.

Commenter (2296-NMED) provides comments on EPA coordinated engagement regarding emissions crossing state borders. The commenter suggests that states, local governments, community organizations, and other stakeholders may find it helpful to create organized groups that can help address interstate air quality issues. For example, the commenter participates in the Four Corners Air Quality Group, which could serve as a model for such coordination. The commenter reports that New Mexico, along with the Navajo Nation, Colorado, Arizona, and Utah meet regularly to address common air quality issues in the region. The commenter explains that the Four Corners Air Quality Group also has a variety of different stakeholders including community members and organizations and industry leaders. They add that the goals and functions of any cross-border groups can, and should, be crafted to the unique needs of the area(s) in which they serve. These organizations can open a dialogue between all stakeholders and include government officials and staff members who can directly address any issues of concern.

Commenter (2225-WESTAR) urges EPA to recognize states' roles as regulatory partner and foster a sense of shared accountability. The commenter requests that EPA do more to engage with oil and gas-producing states, tribes, and local air agencies that will be affected by this rule.

The commenter (2225-WESTAR) notes that states have the responsibility for implementing many important air quality rules, objectives, and policies. The commenter contends that EPA and states' relationship is based on a foundation of transparency and early collaboration. However, the commenter reports that as it applies to the promulgation of this rule in particular, states have felt early collaboration and meaningful engagement to be lacking. The commenter believes that EPA has missed a wealth of information and practical control program knowledge as well as the broadest perspective of how emissions for this sector are managed, by not reaching out through the standing western and national oil and gas working groups that bring together state, tribal, and local air quality agencies.

Commenter (2225-WESTAR) requests that EPA do more to engage with oil and gas-producing states, tribes, and local air agencies that will be affected by this rule. The commenter expresses that states have the responsibility for implementing many important air quality rules, objectives, and policies. The commenter believes that it is critical that a relationship exists between EPA and states that recognizes states' roles as regulatory partners, fosters a sense of shared accountability, and is based on a foundation of transparency and early collaboration. The commenter asserts that, as it applies to the promulgation of this rule in particular, states have felt early collaboration and meaningful engagement to be lacking. The commenter contends that EPA has missed a wealth of information and practical control program knowledge as well as the broadest perspective of how emissions for this sector are managed, by not reaching out through the

standing western and national oil & gas working groups that bring together state, tribal, and local air quality agencies.

The commenter (2225-WESTAR) believes that a plan to meet with state, tribal, and local air agencies, gather necessary information, and conduct analyses to address the control concepts proposed are all necessary steps to develop effective and efficient regulations. The commenter previously encouraged EPA to provide ample time for public comment and engagement. However, the commenter notes that EPA did not engage or provide opportunities to engage in potentially constructive dialogues with states, tribes, and local air agencies between the November 2021 proposed rule and the December 2022 publication of the supplemental proposal. The December 2022 supplemental proposal significantly broadens the November 2021 proposal, and the commenter contends that local air agencies were not given adequate time to assess the impact these significant policy and technical requirements may have on their air programs. According to the commenter, a 60-day comment period makes it difficult for states, Tribal, and local air programs to provide more substantial comments and input based on their experience and knowledge. Commenter (2220-WDEQ) urges EPA to conduct meaningful engagement with state agencies to gather perspectives and input. The commenter supports workable flexibilities instead of a “one-size-fits-all” approach to implementing environmental laws. The commenter recommends that EPA consider workable flexibilities in developing a final rule and urges EPA to engage with state co-regulators early and often to ensure that any new regulation is appropriate and can be reasonably implemented.

The commenter (2220-WDEQ) reports that there is a large number of recurring concerns with the proposed regulatory texts that are shared by other state-level agencies. The commenter asserts that this amplifies implementation issues. The commenter states that state-level regulatory agencies serve as co-regulators with EPA. To develop effective environmental regulations that both achieve emission reductions and can be practicably implemented, the commenter stresses the importance that EPA conduct meaningful engagement with state agencies to gather perspectives and input for formulating final rules. The commenter expresses disappointment that EPA did not respond to reasonable comment period extension requests on the supplemental proposal from Association of Air Pollution Control Agencies (AAPCA) state, local, and tribal member agencies Kentucky Department of Air Quality (KY DAQ), Oklahoma Department of Environmental Quality (KDEQ) Pennsylvania Department of Environmental Protection (PA DEP), Texas Commission on Environmental Quality (TCEQ), the Ute Indian Tribe, and Wyoming Department of Environmental Quality (WDEQ), as well as AAPCA itself.

The commenter (2220-WDEQ) further notes that state plan requirements were not the only overlapping area of concern cited by other state agencies and air quality organizations in the supplemental proposal. The commenter requests that EPA consider the other overlapping concerns raised by the Western States Air Resources Council (WESTAR) in its comments on the supplemental proposal. The commenter states that WESTAR serves as the multi-jurisdictional organization for state, local, and tribal member agencies in the Western U.S. and represents a broad spectrum of air quality perspectives. The commenter reports that members of WESTAR have raised overlapping concerns with the state plan requirements, requirements pertaining to the Super Emitter Response Program, etc., within the December 2022 supplemental proposal indicates that there are significant implementation issues with the supplemental proposal.

The commenter (2220-WDEQ) asserts that EPA has not meaningfully engaged with state agencies on either the original or supplemental proposal. The commenter reports that EPA did not respond, acknowledge nor engage with the commenter upon submission of comments. The commenter acknowledges that EPA conducted a sparse number of virtual public listening and stakeholder engagement sessions on the proposed rule in summer 2021, there were none held in the interim between the close of the public comment period on the November 2021 proposed rule and the issuance of the December 2022 supplemental proposal. Furthermore, the commenter notes that EPA held no in-person meetings with state agencies to our knowledge, and the commenter was not provided with the opportunity to engage in constructive dialogues with EPA about the proposed rule or supplemental proposal.

The commenter (2220-WDEQ) reports that in the supplemental proposal, EPA has clearly focused on the concept of “meaningful engagement.” However, in the commenter’s experience, EPA has not followed these practices in its promulgation of the original proposed rule or the supplemental proposal.

The commenter (2220-WDEQ) believes that it is disingenuous and unreasonable for EPA to propose such extensive meaningful engagement requirements that state, local, and tribal agencies must follow in developing state plans when EPA has not adhered to any of those same requirements in the development of the proposed rules. The commenter believes that EPA is enacting a double-standard that is not consistent with its own legal requirements it proposes for state-level agencies. Furthermore, the commenter asserts that EPA’s actions are not consistent with the basic tenets of cooperative federalism.

Commenter (2429-WOC) states that there is a continued need for state consultation cooperation and support through the state implementation process to ensure that the rule is effective and politically durable.

The commenter (2429-WOC) states that Wyoming is a rural, conservative state that is heavily dependent on the taxes paid by the fossil fuel industry. The commenter contends that Wyoming experienced the whiplash of agency rulemaking from administration to administration. The commenter encourages EPA to recognize the limited capacity of state environmental agencies to respond to the administrative and staffing burden the supplemental rules likely impose. Specifically in Wyoming, a combination of Covid-era state budget cuts and agency position vacancies will make the implementation of these rules difficult without considerable federal resources and support. The commenter encourages EPA to be proactive in its outreach efforts to work with state agencies, involve them in decision making, and be responsive to their concerns. The commenter also encourages strong federal coordination and assistance in helping to identify funding opportunities from recent legislation (such as the Inflation Reduction Act (IRA) and Bipartisan Infrastructure Act) that might provide assistance, recognizing that the states most in need of these resources will likely have the fewest resources to independently pursue them.

Commenter (2403-PAO) requests that EPA coordinate with states and incorporate ways to reduce process requirements to allow states the flexibility (as allowed by the CAA) to develop and implement state specific requirements for existing emission sources. The commenter (2403-PAO) asserts that by dividing regulatory authority under CAA section 111 into separate

programs for new and existing sources, Congress clearly recognized that existing sources are less able to comply with new regulatory requirements than new sources. The commenter notes that if states do not adhere to the presumptive standards for existing sources, state delegated agencies would be required to conduct lengthy analysis and write major regulations or face imposition of a federal plan. The commenter contends that EPA is basically forcing states to “accept” the proposed standards.

Response II-19-42: The EPA’s extensive public engagement in the development of this action is discussed in section VII of the final rule preamble. The EPA remains committed to working with states as they develop and submit state plans to the Agency for review. The EPA strives to maintain consistency in its collaboration with states to ensure that implementation of the EG will be uniform.

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#### ***19.4.5 Prescription of Meaningful Engagement Requirements Exceed EPA’s Regulatory Authority***

Comment: Several commenters (2202-TXOGA, 2258-MSA, 2292-WVAG et al, 2428-API) assert that EPA does not have authority under the CAA to prescribe meaningful engagement requirements. Examples of provided comments are presented in the following paragraphs.

Commenter (2258-MSA) expresses concern that EPA could reject a state plan, no matter how environmentally stringent its provisions are, based solely on EPA’s opinion regarding the extent of “meaningful engagement”. The commenter asserts that the CAA only empowers EPA to evaluate the environmental adequacy of a state plan.

Commenter (2202-TXOGA) states that EPA has failed to identify the source of its authority under CAA to impose meaningful engagement requirements. The commenter notes that the proposed approach requires further explanation. The commenter reports that while the December 2022 supplemental proposal has provided considerably more detail regarding the parameters of its proposed “meaningful engagement” requirements, EPA has failed to identify the source of its authority under the CAA to impose such requirements on the states.<sup>154</sup> The commenter states that the preamble merely makes reference to CAA section 111(d), points to the “public health and welfare objectives of section 111(d)” of the CAA in “regulating specific existing sources,” and concludes that it is “reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives.” According to the commenter, whether the proposed new “meaningful engagement” requirements are “reasonable”

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<sup>154</sup> The commenter notes that EPA states providing notification of public engagement through the internet may not be sufficient because there “cannot be a presumption that such notification is adequate in reaching all those who are impacted by a CAA section 111(d) state plan and would benefit the most from participating in a public hearing.” 87 Fed. Reg. at 74,829. Historically, public notice has been provided in the *Federal Register*, either in print copy or on the internet, and Congress has not indicated that such notice is insufficient as a legal matter.

or not in this context cannot substitute for identifying the source of authority to impose them on state agencies, particularly without providing an explanation of what “meaningful engagement” even means. The commenter adds that the preamble invokes CAA section 301(a)(1), describing that residual rulemaking provision, as it has previously done in analogous circumstances, as an open-ended grant of authority to the Agency to “prescribe such regulations ‘as are necessary to carry out to [its] functions under [the CAA].’” The commenter suggests that resorting to CAA 301(a)(1) here is telling, in that it reveals no express grant of authority for the proposed “meaningful engagement” requirements exists. The commenter reports that set forth in a section of the CAA entitled “Administration,” CAA section 301(a)(1) references the authority of the Administrator “to prescribe such regulations as are necessary to carry out his functions” under the CAA. The commenter states that this language, which speaks to the Administrator’s having some limited authority to adopt rules in furtherance of his own “functions” under the CAA, has never been construed as conferring on EPA any sort of open-ended, substantive authority to adopt whatever rules the Agency may deem to be necessary to advance policy goals. To the contrary, the commenter reports that in those cases where the U.S. Court of Appeals for the D.C. Circuit has addressed the matter, the court has emphasized the circumscribed reach of the Administrator’s rulemaking authority under CAA section 301(a)(1).<sup>155</sup>

The commenter (2202-TXOGA) believes that even this caselaw may be read as overstating the scope of EPA’s authority under CAA section 301(a)(1), insofar as it appears that, to date, the D.C. Circuit has not had occasion to focus on the potential significance of Congress’s use of the term “functions” in the provision. The commenter reports more details in this respect in *Gonzales v. Oregon*,<sup>156</sup> where the Supreme Court had occasion to address a provision of the Controlled Substances Act (“CSA”) – i.e., 21 U.S.C Section 871(b) – the language of which parallels in significant part that of CAA section 301(a)(1), and which provides that the Attorney General of the U.S. “may promulgate and enforce any rules, regulations, and procedures which he may *deem necessary* and appropriate for *the efficient execution of his functions* under this subchapter.” (emphases added). After observing that the “limits on the Attorney General’s authority to define medical standards for the care and treatment of patients” under other portions of the CSA “bear . . . on the proper interpretation of § 871(b),” the Court found that the provision’s reference to the Attorney General’s being authorized to “best determine how to execute ‘his functions’” did not extend so far as to allow the Attorney General to “define the substantive standards of medical practice as part of his authority.”<sup>157</sup> The Court explained that it “would go . . . against the plain language of the text to treat a delegation for the ‘*execution*’ of *his functions* as a further delegation to define other functions well beyond the statute’s specific grants of authority.”<sup>158</sup> “When Congress chooses to delegate a power of this extent,” the Court continued, “it does so *not by referring back to the administrator’s functions* but by giving authority over the provisions of the statute he is to interpret.”<sup>159</sup>

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<sup>155</sup> See, e.g., *NRDC v. EPA*, 749 F.3d 1055, 1063 (D.C. Cir. 2014) (“EPA’s authority to issue ancillary regulations is not open-ended, particularly when there is statutory language on point.”); accord *American Petroleum Institute v. EPA*, 52 F.2d 1113 (D.C. Cir. 1995); *NRDC v. Reilly*, 976 F.2d 36 (D.C. Cir. 1992); *Sierra Club v. EPA*, 719 F.2d 436 (D.C. Cir. 1983).

<sup>156</sup> 546 U.S. 243 (2006).

<sup>157</sup> *Id.* at 264.

<sup>158</sup> *Id.* at 264-65.

<sup>159</sup> *Id.* at 265.

The commenter (2202-TXOGA) notes that EPA indicates a view that the “proposed meaningful engagement requirements” would serve to “effectuate the EPA’s *function* under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section.” But under the Court’s reasoning in *Gonzales*, the promulgation of rules establishing preferred “meaningful engagement” requirements are not an obvious “function” of the Administrator within the meaning of CAA section 301(a)(1), insofar as EPA can point to nothing that either directs or authorizes the Administrator to adopt such rules. And, in any event, by characterizing the proposed new requirements as “effectuating” EPA’s “function” under CAA section 111(d) in “prescribing a process under which states submit plans to implement the statutory directives of this section,” the commenter believes that EPA is tacitly conceding that the new requirements are not “*necessary* to carry out [the Administrator’s] functions” under the CAA. After all, the commenter contends that a process under which states submit such plans has been in place for nearly 50 years now, without there being any such requirements in place. Given this, the commenter believes that such requirements are not readily characterized as “necessary,” within the meaning of CAA section 301(a)(1).

Commenter (2292-WVAG et al) asserts that the CAA does not support EPA’s proposal to dictate day-to-day details of state administrative processes while measuring those processes against some undisclosed standard. The commenter expresses concern with the lack of guidance provided to states. The commenter notes that EPA has constructed new obstacles to the successful approval of a state plan submitted under CAA section 111(d), particularly through what they state are ambiguous “meaningful engagement” requirements, and requirements for more community engagement. The commenter contends that the agency ominously warns that insufficient “demonstrations” of “meaningful engagement” can now be “grounds for the EPA to find the submission incomplete or to disapprove the plan.” The commenter notes that EPA has provided little guidance on how to meet these new requirements. Instead, they state that the EPA has offered only an “example”—a description of its efforts in developing the proposed rule—that it then declares the new “minimum.” The commenter believes that even this “example” is heavy on the vagaries, as when EPA obliquely says that it “engaged with community leaders ... by hosting a meeting with [the] EJ community.” The commenter notes that states are now told that they, too, must identify such “vulnerable” communities—even including communities that are outside the state. In short, rather than preserving the discretion that CAA section 111(d) anticipated, the commenter states that EPA proposes to dictate administrative processes.

Commenter (2428-API) asserts that EPA does not have authority under CAA to dictate meaningful engagement requirements. The commenter supports full and fair public process in the development and implementation of CAA programs. The commenter believes that all affected entities should have reasonable opportunity to know about and participate in the development of regulations that affect their interests. The commenter contends, however, that EPA can encourage meaningful engagement but that it cannot be a required element of approvable state CAA section 111(d) programs, for the following reasons.

First, the commenter (2428-API) asserts that CAA section 111(d) states only that EPA shall establish a “procedure similar to that provided by section 7410 of this title under which each [s]tate shall submit to the Administrator a plan.” This requirement to establish a “procedure” for “submit[ting] ... a plan” unambiguously is directed only at the review and approval process as



between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, the commenter states that CAA section 111(d) directs EPA to emulate only some of the CAA section 110 requirements – not all of them. The commenter therefore asserts that CAA section 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. According to the commenter, it only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a “reasonable notice” standard applies to the development of state plans under CAA section 111(d), the commenter (2428-API) asserts that it is the states’ responsibility to ascertain what is reasonable – not EPA’s. The commenter notes that CAA section 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, they point out that under this “cooperative federalism” scheme, “air pollution control at its source is the primary responsibility of [s]tates and local governments.” CAA section 101(a)(3). In the earliest days of the CAA, the commenter notes that the U.S. Supreme Court confirmed that the CAA “gives the Agency no authority to question the wisdom of a [s]tate’s choices of emission limitations” if the limitations accomplish the goals of the CAA.<sup>160</sup>

The commenter (2428-API) contends that implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a “reasonable notice” obligation is imposed upon the states by CAA section 111(d), the commenter asserts that states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, the commenter asserts that it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, the commenter believes that the EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes “reasonable notice” during the development of state plans, the commenter (2428-API) contends that the proposed “meaningful engagement” requirement goes beyond what EPA may reasonably require. To begin, the commenter states that the term “notice” unambiguously means notification of those with interest in the matter at hand. The commenter believes that the proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome “barriers to participation” by “pertinent stakeholders”) and make targeted outreach go well beyond the nominal statutory obligation of notification. The commenter notes that EPA may “think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear.”<sup>161</sup> However, the commenter states that Congress has imposed no explicit requirements and stated no intent in CAA section 111 or anywhere else in the CAA related to accomplishing

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<sup>160</sup> *Train v. NRDC*, 421 U.S. 60, 79 (1975).

<sup>161</sup> *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018).

any particular environmental justice goals or outcomes. According to the commenter, the word “notice” cannot carry as much meaning as EPA believes it should.

As for CAA section 301, the commenter (2428-API) states that it has long been understood that that provision does not “provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes.”<sup>162</sup> Here, CAA section 301(a)(1) is inapplicable because creating a new category of procedural requirements is not “necessary” for the Administrator “to carry out his functions under this chapter.” CAA section 301(a)(1). The commenter believes that EPA’s intentions are commendable, but that the proposed “meaningful engagement” procedures are not “necessary” as that term is used in CAA section 301.

Lastly, the commenter (2428-API) asserts that EPA’s proposed “meaningful engagement” procedures are not adequately clear and objective. As noted above, the commenter notes that Congress has not spoken in the CAA to the issue of environmental justice. The commenter explains that the EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.<sup>163</sup> Moreover, the commenter believes that EPA’s criteria for determining the adequacy of state “meaningful engagement” efforts are vague and EPA’s authority under its proposed rules to accept or deny a state’s efforts is not bounded by any readily objectively discernable principles. The commenter questions: 1) how does EPA determine the manner of required engagement with any particular stakeholders? 2) How does EPA decide what constitutes an actionable “linguistic, cultural, institutional, geographic, [or] other barrier” and, where such barriers are determined to exist, whether the state’s proposed approach is sufficient? 3) What measures are needed for state programs to be adequately inclusive? The commenter states that the statute does not expressly address those questions and EPA has not addressed these questions in its proposed rule. As a result, the commenter asserts that the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious.<sup>164</sup>

Response II-19-43: EPA has separately finalized meaningful engagement requirements in the final Implementing Regulations rulemaking, 88 FR 80480 (November 17, 2023).

Please see the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

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<sup>162</sup> *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted).

<sup>163</sup> It is notable that the 2022 “Inflation Reduction Act” included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA section 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

<sup>164</sup> *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

#### ***19.4.6 Improvements to EJ Screen Tool***

Comment: Commenter (2186-MDNR) recommends improvements to EPA’s environmental justice screening and mapping tool, EJ Screen. The commenter states that EJ Screen is likely the tool that states will use to screen for areas that may be considered overburdened or underserved, and thus the focus of the new community engagement requirements. However, the commenter notes that EJ Screen does not offer any information regarding the locations of oil and natural gas facilities. The commenter contends that if data regarding proximity to oil and natural gas facilities was available in EJ Screen, similar to that of superfund proximity, it could benefit states in prioritizing community engagement activities during development of the state CAA section 111(d) plans.

Response II-19-44: EPA acknowledges the commenter’s suggestions.

### **19.5 Components of State Plan Submission**

#### ***19.5.1 Presumptive Standards Model Rule Language***

Comment: Commenters (2249-NACAA, 2425-TSC) support the creation of model rule language that can be incorporated directly or by reference into state plans. Some of the specific comments provided are presented in the following paragraphs.

Commenter (2425-TSC) supports the development of a model rule for use in state plans. The commenter recognizes the need for a consistent regulatory regime for tracking and limiting methane emissions. The commenter notes that although some states have promulgated rules to regulate the emission of methane from this sector, there are still many places where oil and gas operations are largely unregulated. The commenter agrees with EPA’s assertion<sup>165</sup> that the success of this rulemaking will depend largely on the effectiveness of the state plans adopted in coordination with EPA.

The commenter (2425-TSC) further supports EPA’s proposal to create presumptive standards based on “general industry parameters and assumptions,” which states may use as a “model rule” in the development of state plans. The commenter agrees that it will allow states to create standards that would be equivalent to the presumptive standards, in the aggregate. In addition, the commenter supports the provision that would allow states to include requirements that are more stringent than the guidelines because of, “early retirements, effects on local communities, and availability of control technologies that allow a source to achieve greater emission reductions,” provided states can demonstrate their efficacy. The commenter notes that the proposal gives states the discretion and flexibilities to meet EGs through aggregate reduction from their sources and allows methods like trading and averaging. The commenter cautions, however, that as EPA moves forward with EGs for states governing existing sources, EPA

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<sup>165</sup> EPA, “Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” Oct 2021. [https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsp-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsp-eg-climate-review_0.pdf).

ensure that these guidelines are not undercut by efforts to provide flexibility to states to carry over less stringent provisions from any existing state programs.

Commenter (2249-NACAA) supports the development of an example state plan and model rule language for each segment of the oil and gas industry regulated by adopted rule that can be incorporated directly or by reference to meet EPA's EGs. The commenter asserts that while there are some state programs that are already being implemented or well developed in the proposal stage, many agencies will benefit from a model rule. The commenter believes that the opportunity to adopt preapproved rule language, in addition to the option to develop a unique state plan in accordance with the guidelines, is consistent with the CAA's cooperative approach and will expand state compliance options while conserving state resources.

Similarly, commenter (2418-SD DANR) recommends that EPA simplify the rule making process to allow state's plan to adopt parts or all the federal plan by reference.

Response II-19-45: EPA acknowledges the commenter's support for the model rule.

Comment: Commenter (2363-CEMC) supports EPA allowing states to use approved alternative test methods in their state plans—rather than require a state having to go through a separate “equivalency” demonstration for such methods. The commenter believes EPA's approach is important and valuable because, by the time that states are developing and submitting their EG OOOOc plans, the agency will hopefully have approved several methods. The commenter states that this will make it possible for state plans to authorize or require the use of technologies that provide improved detection and more precise quantification.

Response II-19-46: The EPA acknowledges the commenters support and clarifies in section XIII.C.2 of the final rule preamble how we intend the steps of the source-by-source equivalency determination to work with regards to the approval of alternative technologies.

Comment: Commenter (2218-TCEQ) requests that EPA reduce the volume of reports required to be submitted. Given the potentially hundreds of thousands of sites in Texas subject to this proposed rule, the state will not be able to process the number of reports, notifications and requests required to be submitted under this rule. The commenter states that each report is detailed and extensive and examples include increment of progress, corrective action plans, well closures plans, notification of intent to close, notification of compliance report, notifications under 40 CFR 60.7(a)(1), (3), and (4) and 40 CFR 60.15(d), annual reports, performance test reports, semiannual reports, additional reporting under alternative GHG standards for fugitive emissions components designated facilities and covers and closed vent systems, alternate fugitive emission standards, and requests for Alternative Means of Emissions Limitation under 40 CFR 60.5399c. The commenter asserts that the volume of reports and the amount of information submitted is more than state agencies can reasonably oversee.

Response II-19-47: Please see section X.N of the final rule preamble.

Comment: Commenter (2428-API) points out that EG OOOOc model rule language makes eight references to a 40 CFR 60.5933c, one of which gives its title as “Alternative Means of Emissions

Limitation.” However, the commenter notes that there is no actual section in EG OOOOc with that number or title.

Response II-19-48: The EPA acknowledges this was an inadvertent drafting error in the proposed model rule text. The EPA has corrected this error in the final EG OOOOc rule text.

### ***19.5.2 Emissions Inventory Requirements***

Comment: Several commenters (2218-TCEQ, 2286-CDPHE, 2296-NMED, 2393-OSEE, 2410-CA AG et al) support the use of existing emissions inventory data to fulfill state plan requirements. Commenter (2218-TCEQ) supports the use of the Greenhouse Gas Reporting Program (GHGRP) data. Commenters (2296-NMED, 2393-OSEE) do not support the use of GHGRP data due to the large reporting threshold. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (2410-CA AG et al) recommends that EPA allow states to use existing emission inventories and emissions data, even if that data may not be fully aligned with the designated facilities in the EG. The commenter reiterates their initial proposal comments that existing inventories and EGs should be allowed provided that the data submitted by the state is rigorous and comprehensive enough to accurately capture emissions from the oil and natural gas industry.

Commenter (2218-TCEQ) supports using the annual emissions inventory data reported by the oil and gas industry as part of the GHGRP to fulfill the EG OOOOc state plan emissions inventory requirement for these sources. The commenter supports EPA’s use of GHGRP data to supersede the requirements of 40 CFR 60.25a(a) for the purposes of the proposed EGs so that state plans are not required to include an inventory and emissions data. The commenter asserts that if EPA decides instead to require states to collect, assess, and report annual GHG emissions inventory data, the resource burden would be staggering. Based on previous efforts to inventory ozone precursor emissions, the commenter estimates that approximately 21,000 additional sites would be required to report annually, a 10-fold increase of the current number of reporting point sources. The commenter reports that it would need to hire 50 additional full-time employees to perform basic quality assurance of reported data, and additional database and information technology (IT) resources would be required to handle the increase in reporting sources. Even with additional employees and adequate IT infrastructure, the commenter estimates it would take two to three years to collect and report each year’s GHG emissions data to EPA due to the immense number of sources.

Commenter (2286-CO APCD) supports EPA’s proposal to supersede the requirements of 40 CFR 60.25a(a) for purposes of the proposed EG so that state plans do not have to include an inventory and emissions data as described. The commenter appreciates EPA’s recognition of the complexity related to identifying all the designated facilities and associated emissions as defined in EPA’s proposed EG. The commenter states that Colorado does require extensive reporting by the oil and gas owners and operators in Colorado, and this reporting does show frequent emissions, operational, and ownership changes. Should EPA finalize the requirements related to providing emissions inventories with a state CAA section 111(d) plan as proposed, the

commenter will certainly look to holistically utilize its state-wide inventory and emissions data in developing and supporting Colorado's CAA section 111(d) plan.

Commenter (2296-NMED) also supports EPA's proposal to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG, and to provide options for the use of different types of emissions data to represent the same general type of information. The commenter supports EPA's proposal to allow states flexibility to utilize existing inventories and emissions data to develop their SIPs as they pertain to EG OOOOc. The commenter does not support the use of GHGRP data but supports allowing states the ability to use other available existing inventory information, so long as the inventory adequately captures data, or estimates emissions from, all potentially affected facilities.

The commenter (2296-NMED) states that the GHGRP includes emissions data from covered sources that exceed 25,000 metric tons per year of CO<sub>2</sub>e. This high threshold eliminates the sources emitting less than 25,000 metric tons per year of GHG. The commenter believes that the GHGRP data should not be used because it would exclude the emissions from thousands of smaller upstream oil and gas facilities, which in the aggregate represent a significant amount of GHG and criteria pollutant emissions.

The commenter (2296-NMED) notes that EPA has identified over 15,000 oil and natural gas facility owners and operators, one million producing onshore oil and natural gas wells, 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and 1,400 transmission compression facilities. The commenter reports that in New Mexico alone, there are over 1,600 permitted oil and natural gas facilities and nearly 55,000 completed oil and natural gas wells. EPA recognizes, and the commenter agrees, that due to the large number of existing oil and natural gas sources and the frequent change of configuration and/or ownership, it may not be practical to require states to compile emissions data in the same way as is typically done for other industries. The commenter adds that the EPA recognizes that states may not have a GHG emissions inventory of all designated facilities already available and that creating such an inventory would be resource intensive. The commenter has collected many years of data on criteria pollutants from Title V sources; and in 2021, the commenter conducted a comprehensive minor source emissions inventory of criteria pollutants. However, a GHG emission inventory for all minor sources has yet to be accomplished for New Mexico, although the commenter is currently planning and working toward conducting a GHG emission inventory from all minor sources. As EPA acknowledges, and the commenter is experiencing, creating such an inventory is time consuming and resource intensive. The commenter agrees with EPA that a highly detailed GHG emissions inventory is not necessary for states to develop standards of performance, and that such standards of performance could be developed using a different type of emissions inventory data.

Commenter (2393-OSEE) reports that Oklahoma regulations state that any source of regulated air pollutants must submit an emission inventory. The December 2022 supplemental proposal would make methane a regulated air pollutant, and thus the commenter notes that for Oklahoma, it could bring in the potential requirement to inventory 202,647 wells, regardless of where EPA obtains the data from to satisfy the requirements of 40 CFR 60.25a(a).

Commenter (2393-OSEE) does not support the use of GHGRP data to satisfy the requirements of 40 CFR 60.25a(a). The commenter believes that the GHGRP data do not accurately represent the needed information. The commenter explains that the GHGRP does not identify all affected sources, as it has a high threshold for reporting. Also, the commenter states that GHGRP does not always utilize actual measurements; and the GHGRP has default emission factors and default equipment counts built in that reporters must utilize. Instead of utilizing GHGRP information, the commenter recommends that EPA accept emissions data for these facilities in accordance with the provisions of the Air Emissions Reporting Requirements (AERR), with detailed requirements for designated facilities that are classified as AERR Type A and B sources and the use of alternative methods (e.g., a nonpoint tool) for designated facilities that would be classified as nonpoint sources under the AERR. The commenter reports that AERR already has emissions thresholds for what should be inventoried as a point source, and what is being captured in the NEI as a nonpoint source. The commenter believes that the rule should align with the AERR thresholds and requirements and suggests that using the NEI would give a much more comprehensive accounting of facilities and provide more accurate emissions.

The commenter (2393-OSEE) provides a comparison of GHGRP and NEI data specifically for the oil and gas sector in Oklahoma, where GHGRP includes 70 facilities<sup>166</sup>, while the NEI accounts for 73,138 facilities<sup>167</sup>. The commenter notes that the threshold for a reportable “facility” to GHGRP is 25,000 metric tons CO<sub>2</sub>e. For companies with wellheads, the company must add up all their wellhead assets in a basin to see if they meet the threshold and if they do, all those wellheads get reported as a single facility. The commenter states that this means that many, possibly most, of the wellheads would be missed in every basin, as there are many small operators in this sector. Conversely, the commenter provides that the EPA's Nonpoint Oil & Gas Tool used for compiling the NEI pulls data from Enverus (formerly DrillingInfo), to account for a vastly larger number of facilities, including both large and small operators.

Commenter (2393-OSEE) suggests that the EPA support state and local agency efforts to incorporate existing research findings into emissions estimates for the oil and gas sector. According to the commenter, researchers have investigated emissions from various facility types in the oil and gas sector. According to the commenter, many of these efforts have been in collaboration with oil and gas companies, university researchers, and representatives from environmental advocacy organizations. However useful this work has been, little of this work has been incorporated directly into the emissions estimates that have been incorporated into the EPA's triennial National Emissions Inventories (NEI). To ensure that valuable research findings are properly incorporated into emissions estimates (including notably the NEI), the commenter suggests that the EPA fund work by states and local agencies, in collaboration with university researchers and the EPA contractors, to evaluate research findings and incorporate results, where warranted, into emissions estimates submitted to the NEI. The commenter contends that state agencies do not currently have the resources to do this on their own.

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<sup>166</sup> GHGRP figure obtained from EPA Flight tool for 2021, filtered for Oklahoma. The count includes Petroleum and Natural Gas Systems.

<sup>167</sup> NEI figure obtained from combination of EPA Nonpoint Oil & Gas Tool for Oklahoma and the Oklahoma Department of Environmental Quality's submission of relevant point sources. 71,683 sources from EPA Nonpoint Oil & Gas Tool for Oklahoma for 2020, plus 1,455 sources submitted as point sources to EPA for 2020.

Response II-19-49: Please see the discussion and response to comments in section XIII.C.5 of the final preamble.

### ***19.5.3 Source-Specific BSER***

Comment: Commenter (2410-CA AG et al) supports the source-specific BSER requirement. The commenter states that the BSER factors encompass all the information relevant to a state's determination of an appropriate emission standard for a facility to which the remaining useful life or other factors could properly apply.

The commenter (2410-CA AG et al) notes that EPA proposal would require the state plan submission to identify all control technologies available for the source and evaluate the BSER factors (cost, non-air quality health and environmental impacts, energy requirements, amount of reductions, and advancement of technology) for each technology.

Response II-19-50: EPA acknowledges the commenter's support.

### ***19.5.4 Process for States to Develop State Plans***

Comment: Commenter (2399-GPA) contends that the December 2022 supplemental proposal is neither the vehicle for proposing revisions to Subpart Ba, nor should it assume that such proposed revisions are already effective.

First, the commenter (2399-GPA) recommends that EPA address any potential changes to the process for states to develop state plans under EPA's separate, pending rulemaking to revise subpart Ba, not this rulemaking.

The Supplemental Proposed Rule's preamble explains EPA would conduct "a source-by-source evaluation" to determine whether a state's submitted program may be deemed equivalent to the proposed presumptive standards. However, the commenter (2399-GPA) state that those criteria are not found in 40 CFR Part 60, Subpart Ba, which governs EPA's review of state plans submitted under CAA section 111(d). EPA notes that it is proposing to revise Subpart Ba through a separate rulemaking, but the commenter adds that the proposed Subpart Ba rule also does not contain or reference the proposed "five basic criteria" described in the December 2022 supplemental proposed rule. The commenter asserts that it is illogical for EPA to be using preamble language to attempt to fashion separate criteria for just this proposal.

EPA also proposes major revisions to when states may consider facilities' RULOF to establish less stringent emission limits for a facility or class of facilities. Here, the commenter (2399-GPA) notes that the December 2022 supplemental proposed rule is clearly mandating that states use the new criteria for RULOF that are not found in existing regulations. Instead, the December 2022 supplemental proposed rule incorporates new standards from the proposed Subpart Ba Rule.

The commenter (2399-GPA) urges EPA to reconsider this approach. By proposing the same or similar revisions in two separate rules, EPA gives the appearance that the Proposed Subpart Ba Rule is a *fait accompli*, already determined by EPA to be effective in practice before it was even



proposed, much less before EPA considered public comments on the Subpart Ba Rule and finalized it. According to the commenter, this is impermissible under the APA.<sup>168</sup>

Instead, the commenter (2399-GPA) recommends that EPA withdraw the portion of the December 2022 supplemental proposed rule that purports to implement revisions to Subpart Ba so that the proposed Subpart Ba Rule may proceed separately and under the normal rulemaking process. The commenter asserts that this does not need to delay this rulemaking. In the meantime, the commenter recommends that EPA simply proceed under existing regulations for state plans while the agency finalizes revisions to subpart Ba.

Response II-19-51: Please see Response II-19-13. EPA does not agree with the commenter regarding their characterization of the APA and the associated caselaw cited. The commenter's citation to the APA is not on-point to the situation here, and the cited caselaw is not relevant here. EPA did consider all comments submitted both on this rulemaking's two proposals as well as those comments submitted on the proposal to amend subpart Ba via a different rulemaking process.

## **19.6 Timing of State Plan Submissions and Compliance Times**

### ***19.6.1 18-Month Plan Submission Timeframe is Inadequate***

Comment: Several commenters (2157-TDEC-DAQ, 2220-WDEQ, 2222-WDNR, 2224-WSARC, 2237-ICND, 2241-UDNR-PLPCO, 2292-WVAG, 2296-NMED, 2310-MDEQ, 2322-ADEE, 2330-KYDAQ, 2393-OOSEE, 2403-PAO, 2410-COAG, 2418-SDDANR, 2446-IPAA) state that the December 2022 proposed rule, if finalized, does not provide adequate time for plan development and state administrative processes for adopting a plan to regulate existing sources. The commenters cite several concerns with the timeframe proposed. The commenters request that the EPA consider the impracticability of the criteria established in 40 CFR 60.5365c of the proposed regulatory text for EG OOOOc and afford states with greater flexibility to effectively implement a State Plan. Examples of some of the specific comments provided are included in the following paragraphs.

Commenter (2446-IPAA) also states that the 18-month schedule to develop state plans will be inadequate for source-by-source determinations. The commenter reports that states will need far longer and that the more low production wells that are in a state, the longer it will need to be.

Commenters (2330-KYDAQ, 2403-PAO) outline factors that affect the time needed for states to develop and submit a plan to the EPA, including:

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<sup>168</sup> See, e.g., *Nat'l Tour Brokers Ass'n v. United States*, 591, F.2d 896, 902-03 (D.C. Cir. 1978) (the purpose of the APA's public comment provision is so that the agency may "benefit from the expertise and input of the parties who file comments" and "maintain[ ] a flexible and open-minded attitude towards its own rules"); *U.S. Steel Corp. v. EPA*, 595 F.2d 207, 214-15 (5th Cir. 1979) (agency must "ensure that affected parties have an opportunity to participate in and influence agency decision making at an early stage, when the agency is more likely to give real consideration to alternative ideas").

- The volume of sources (the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities),
- Limited air regulatory experience of sources,
- Time necessary to create an accurate source inventory,
- The proper notification to those sources and information requests from sources,
- Permit development
- Meaningful engagement and public participation,
- Any regulatory changes that would be necessary before submitting a state plan.
- Additional time would be necessary if the EPA does not propose a Model Rule.
- Develop and draft plans that include the required components, such as standards of performance and implementation measures for such standards.
- Adoption of the plans through their required administrative processes before submitting them to the EPA.

Commenter (2322-ADEE) states that CAA section 111(d)(1) and the EPA's implementing regulations under 40 CFR 60.24a(e) require that states be allowed the opportunity to propose a method other than the EPA's BSER to achieve the required emission reductions (or to propose a standard of performance less stringent than the presumptive standard of performance under a given EG, depending on the affected source's RULOF). The commenter notes that the proposed rule does not address this issue nor its impact on the timeline proposed.

Commenter (2344-ADEE) notes that the average timeline in Arkansas to develop and submit to the EPA a state plan that addresses a straightforward requirement is eighteen months, because of the numerous federal and state administrative procedures required for such an action. The commenter suggests that plans including controversial or complex regulations, such as the December 2022 proposed rule, can reasonably be expected to take longer. Further, the commenter adds that the more complex the standard-setting process, the more time states will need to gather information from designated facilities and perform analyses to set appropriate standards consistent with EGs.

Another commenter (2224-WSARC) provides that many states already have oil and gas control programs in place and will have to follow the EPA's outlined criteria to determine if those programs are equivalent to EG OOOOc. The commenter adds that this includes analyzing and potentially modeling impacted sources, evaluating emission inventories, consulting stakeholders, and examining compliance and enforcement needs, among numerous other actions. In addition to devoting resources toward the implementation of EG OOOOc for previously unregulated sources, state, Tribal, and local air agencies will also need to devote time and resources to review how EG OOOOc documentation fulfills the NSPSs KKK, OOOO, or OOOOa requirements. Since there are many more existing sources than new, modified, and reconstructed sources, the commenter states that these plans will be complex and take time to develop.

Commenter (2220-WDEQ) states that the supplemental proposal, as written, leaves states with the options of adopting the model rule or attempting to undertake an infeasible amount of work given the timeframes allocated. The commenter notes that the only workable option for some

states that have significant oil and gas development operations may be to adopt the EPA's model rule. The commenter suggests that this pathway denies the states their legal right to consider a source's RULOF as established in the CAA (i.e., undertaking a case-by-case application of state-determined standards of performance). The commenter notes that for states to exercise their statutorily mandated authority, the EPA should not dictate emission limits and time schedules.

The commenter (2220-WDEQ) notes that even if state agencies were to adopt the model rule as proposed, the 18-month timeline would not provide states with sufficient time for meeting the requirements. The commenter provides that EG OOOOc requires that states that adopt the model rule submit an inventory of designated facilities and an inventory of emissions from affected designated facilities in its written request for delegation of the Federal plan. The commenter suggests that this would require the state to undertake a state-level information collection request (ICR) that requires allocating sufficient time for sources to respond, along with significant time for state to compile the responses and the required emissions inventory.

Several commenters (2220-WDEQ, 2296-NMED, 2393-OOSEE) state that the burden of gathering an inventory of designated facilities in accordance with 40 CFR 60.5363c(a) alone warrants a longer timeframe. The commenters note that the EG includes thousands of additional sources for oil and gas states. They add that, rarely does an EG affect so many existing sources.

Commenter (2296-NMED) proposes that the EPA grant states with a substantial number of covered sources additional time as needed. The commenter states that this rulemaking will impact more sources in New Mexico (the second largest crude oil producer in the nation and one of the top ten states for natural gas production) than virtually every other state in the nation and impart a significant workload on the state resources, making it difficult to complete a state plan in 18-month timeframe.

Another commenter (2220-WDEQ) states that Wyoming has tens of thousands of sources that could be subject to the proposed requirements of EG OOOOc and that the state air quality division's program currently covers over 18,000 operating single-well sites and compressor stations, and that number does not consider the increase in specific equipment subject to the supplemental proposal's requirements, such as pneumatic pumps and controllers. The commenter expresses concern with the proposed timeline given the workload associated with making the required demonstrations for the thousands of sources in Wyoming, given the factors they face (e.g., remaining useful life, technical infeasibility, etc.).

Several commenters (2220-WDEQ, 2237-ICND, 2393-OOSEE) mention state rulemaking often takes at least a year to go from proposed to effective. In addition to gathering the source inventory and promulgating a state rule, the commenter notes that a state also must determine which facilities might be affected by RULOF in 40 CFR 60.5365c. To consider the remaining life of a source, the commenter explains that states must be able to determine the compliance timeline by considering factors such as the source's anticipated retirement date, costs and benefits of an available technology, and technology that has already been deployed. The commenters request that the EPA provide flexibility in allowing states to consider the remaining useful life of affected facilities, realistically achievable standards, and the timelines in which those standards could be met.

Several commenters (2220-WDEQ, 2222-WDNR, 2393-OOSEE, 2241-UDNR-PLPCO) note that the rule also includes an additional requirement of "meaningful engagement" in 40 CFR 60.5363c(a)(6) and 40 CFR 60.5366c that presumably requires additional outreach beyond what states typically conduct during a routine rulemaking and state CAA section 111(d) plan development. The commenters note that the consequential time and resources required for addressing these requirements would further overburden existing state staff resources and require additional time to for meaningful engagement and cooperation between the state, the EPA, and the tribal nations to address shared jurisdictions.

Commenter (2220-WDEQ) provides that they have significant expertise in meaningful engagement with a comprehensive spectrum of stakeholders and crafting effective regulation for existing sources. According to the commenter, the rulemaking process requires an internal draft development phase, numerous outreach meetings to stakeholders, and two Air Quality Advisory Board meetings. At the Air Quality Advisory Board meeting for one proposal, the state agency received significant comment that prompted additional review and revisions, and an Environmental Quality Council hearing. In all, the commenter reports that it took more than 18 months of development, stakeholder engagement, and statutory process for that proposed rule to become effective. The commenter emphasizes that the example proposed rule only addressed existing sources in one region of the state, and that the work necessary to implement the supplemental proposal will affect sources statewide.

Several commenters (2157-TDEC-DAQ, 2224-WSARC, 2237-ICND, 2292-WVAG, 2393-OOSEE) assert that, in addition to the EPA receiving inadequate or incomplete plans, there are potential risks or consequences of not providing adequate time to develop state plans.

Commenter (2393-OOSEE) notes that the EPA will be facing the need to develop a federal plan and implement the EGs themselves. The commenter suggests that the EPA does not seem to have the manpower to do this adequately. According to the commenter, recent experiences with the Municipal Solid Waste Landfill Emission Guidelines and the subsequent Federal Implementation Plan (FIP) have shown that even with a relatively small number of sources, the EPA is unprepared to receive and review the documentation required.

Another commenter (2237-ICND) states that it may lead to a similar event to what the U.S. experienced with the EPA's highly rushed and consequently inadequate NSPS OOOO and NSPS OOOOa regulations. According to the commenter, these recent NSPS OOOOa regulations were obviously not well vetted since NSPS OOOOb is newly proposed and subsequently EG OOOOc will retroactively 'correct' errors, inconsistencies, and items overlooked under NSPSs OOOO/OOOOa. The commenter suggests that this issue could have been avoided altogether if the EPA had simply meaningfully engaged with oil and gas producing states as the EPA developed these regulations.

Commenter (2157-TDEC-DAQ) indicates that a possible consequence of the EPA's action would be to federalize a portion of the CAA, to subvert a state's ability to develop the best plan for that state, and to undermine the federal-state partnership that the Act envisions.

Response II-19-52: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble.

Comment: Commenter (2241-UDNR-PLPCO) states that the state of Utah already has an established program to regulate oil and gas emission sources, though focused on VOC emissions. The plan the state is to develop is required to be equivalent to the EPAs proposed NSPS OOOOb and EG OOOOc requirements, thus includes methane emissions from oil and gas sources. As methane is not a pollutant that has been previously regulated by the State of Utah, it is unrealistic for the state to collect an emission inventory, understand the monitoring and quantification of potential methane emissions, determinate stakeholders and have meaningful engagement, evaluate equivalency of current standards to the proposed NSPS OOOOb and EG OOOOc requirements and understand the impacts of compliance with the plan, all in 18 months. The commenter notes that, considering the long-time frame taken previously by the EPA to prepare and promulgate a FIP for the Uinta Basin (UB) ozone NAAQS, Utah is again uncertain the EPA or the Ute Tribe will develop this plan in a timely manner once again leaving the UB in a situation where there are unequal regulatory requirements on adjacent lands in a shared airshed.

Response II-19-53: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble. The EPA clarifies that the EG OOOOc does not require states to develop emissions inventories (see preamble discussion XIII.C.5.). Nor does EG OOOOc require a state to leverage their existing state programs for purposes of their plan submittal, but rather as discussed in preamble section XIII.B.2, offers state the flexibility to do so if they choose. Lastly the EPA is not finalizing the provision for meaningful engagement in EG OOOOc. Rather, since similar revisions to subpart Ba are now final at 88 FR 80480 (November 17, 2023), and are therefore applicable to the EG OOOOc, state plans must be submitted according to the provisions in 40 CFR 60.23a(i) which requires states to document in their plan submittals how they provided meaningful engagement with the pertinent stakeholders. Please see section XIII.C.6 of the preamble.

Comment: Several commenters (2157-TDEC-DAQ, 2220-WDEQ, 2296-NMED, 2330-KYDAQ, 2410-COAG, 2418-SDDANR) provide recommendations for a timeline for state plan development and submission. Specific comments are provided in the following paragraphs.

Commenter (2157-TDEC-DAQ) states that an 18-month deadline may be sufficient for states that do not use RULOF and perform the minimum amount of engagement for a plan that mirrors what the EPA has set forth, but more time is required for states that do not adopt the EPA's EGs as written or to conduct any additional engagement. Specifically, the commenter notes that a state may not initially know RULOF is required. Therefore, the commenter adds that the state will need to identify specific facilities and assess whether those facilities can comply with the rule as written. The commenter explains that the amount of time required to complete this step cannot be determined with certainty, but six to eight months is our best estimate (one to two months to identify and contact potentially affected facilities, one to three months for the facility to send a response, and one to two months to review the facilities' responses). Then, once all information is collected and reviewed, states will need to develop their CAA section 111(d) plans. This step can probably be completed in one year if the state elects not to use RULOF for any facilities. The commenter notes that states that must establish standards based on RULOF

are likely to need a minimum of six additional months to complete this step<sup>169</sup>. The commenter provides that this estimate does not include the additional time that will be required to comply with the EPA's meaningful engagement requirements. Therefore, the commenter believes that 24 months is the minimum amount of time that would be required to submit a CAA section 111(d) plan that includes RULOF. The commenter states that they do not know how much time will be required to comply with the EPA's meaningful engagement requirements, but it seems likely that a further extension of three to six months would be necessary. With all these requirements considered, the commenter believes that 30 months is necessary for states to develop CAA section 111(d) plans. The commenter contends that considering the required engineering analyses and meaningful engagement requirements<sup>170</sup>, any shorter deadline will foreclose a state's ability to consider RULOF as allowed by CAA section 111(d).

Commenters (2220-WDEQ, 2410-CA AG et al) request that the EPA extend the effective date for the supplemental proposal and allocate more time to implement the requirements of the proposed EGs. Commenter (2410-CA AG et al) urges EPA to establish the shortest time frame necessary to accommodate the administrative procedures of the states charged with implementing the guideline.

Commenter (2296-NMED) urge that EPA grant states with a substantial number of covered sources additional time as needed.

Commenter (2330-KYDAQ) suggests extending the deadline for state plan submissions to a minimum of 24 months after a final EG is published.

One commenter (2418-SDDANR) agrees it is possible to submit a plan to the EPA within 18 months if everything runs smoothly. However, the commenter recommends the EPA allow for an extension in cases where the state rulemaking process is delayed or held up by significant opposition.

Several commenters (2222-WDNR, 2225-WSARC, 2237-ICND, 2241-UDNR-PLPCO, 2310-MDEQ, 2322-ADEE, 2393-OOSEE, 2403-PAO) requests that the EPA extend the submission timeline contained in 40 CFR 60.23a(a)(1) to three years.

Response II-19-54: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble.

### ***19.6.2 18-Month Plan Submission Timeframe is Too Long***

Comment: Commenters (2201-WVHC, 2433-EDF et al) state that the 18-month submission period is too long.

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<sup>169</sup> The commenter notes that EPA frequently requests consultation and submittal of pre-draft documents prior to the public comment period, and these steps can add substantially to the timeline.

<sup>170</sup> The DC Circuit's 2021 vacature of the Subpart Ba requirements in *Am. Lung Assoc. v. EPA*, 985 F.3d at 991 (D.C. Cir. 2021) addressed EPA's general requirement to submit state plans within three years but did not foreclose a longer deadline where circumstances warrant.

Commenter (2201-WVHC) suggests that six months would be plenty; and that a year would be more than enough.

Commenters (2392-Earthjustice et al, 2433-EDF et al) urge the EPA to retain the 15 months provided in the general provisions for plan submittals under the EG OOOOc rules.

Commenter (2433-EDF) contends that the agency offers no evidence in either rulemaking to suggest that state-level administrative processes are different for oil and gas sources than for any other source category, and so offers no reason why 18 rather than 15 months are necessary to accommodate state plan development in this category. Although the agency claims in a footnote to the CAA section 111(d) implementation proposal that a longer timeline is necessary in EG OOOOc “due to the size and variety of emission sources in the oil and gas sector,”<sup>171</sup> the commenter notes that this justification appears nowhere in the EG OOOOc preamble itself and does not support an 18-month rather than 15-month submission period in any event.

Commenter (2433-EDF et al) asserts that, particularly given the urgent nature of climate change, the EPA must ensure that its proposed EG OOOOc are implemented as swiftly as possible. The commenter urges the EPA to apply the proposed default 15-month timeline for state plan submissions under EG OOOOc rather than the extended 18-month period. Similarly, they encourage the EPA to consider adopting a more accelerated timeframe than 12 months for state plan approval and recommend that EPA instead explore whether a 9-month (or even shorter) window is feasible.

Response II-19-55: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble.

### ***19.6.3 Specific State/Tribal Issues with 18-month Timeframe for Plan Submission***

Comment: Commenter (2241-UT DNR) expresses concerns regarding the timeliness of federal action and resources to implement the proposed requirements. The commenter states that most oil and gas sources in Utah are in the UB where there is shared air quality jurisdiction with the state, the EPA, and Ute Tribe over oil and gas emissions. The commenter notes that the 2017 oil and gas emission inventory for the UB indicates that 80 percent of the VOC emissions are from sources under the EPA and tribal regulatory control. This has been acknowledged by the EPA with the issuance of the “Federal Implementation Plan for Managing Emissions from Oil and Natural Gas Sources on Indian Country Lands Within the Uintah and Ouray Indian Reservation in Utah” published in the December 8, 2022 (87 FR 75334). There is a one-year implementation time period for existing sources to implement and comply with the FIP, which is February 6, 2024. The commenter provides that the FIP reflects standards and requirements established by UDAQ many years ago and though very much supported and appreciated, it was not issued until almost five years from designation as an ozone nonattainment area (NAA) in 2018.

With the proposed FIP, the commenter (2241-UT DNR) states that these new proposed EPA standards under NSPS OOOO, the BLM’s “Waste Prevention, Production Subject to Royalties, and Resource Conservation” proposed rules, and the EPA’s December 2022 proposal updating

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<sup>171</sup> 87 Fed. Reg. at 79181 n.8.

requirements to the “Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under the Clean Air Act Section 111(d)” there is a large amount of regulation proposed to address emissions from oil and gas sources. As such, they add that there is a large amount of complexity and uncertainty for states in how to manage all these changes and understand how they all interconnect and function together in the proposed short time frames. The commenter further adds that federal agencies will also have to effectively resource, manage and implement these programs in the UB where they have jurisdiction over most impacted sources. As such the commenter requests that the EPA engage with the Utah Department of Air Quality (UDAQ) and the Ute Tribe in a meaningful and timely way such that we can effectively and reasonably manage our resources and provide clear regulatory guidance to impacted sources. The commenter contends that there should be more time provided to fully understand these changes and implement them effectively.

Response II-19-56: Please see the discussion and response to comments on the timing of state plan submittals and compliance timelines in section XIII.E. of the final preamble.

Comment: Commenter (2427-UPA) states that adequate implementation timing and clarity must be provided for areas subject to a federal plan under proposed 40 CFR 60.5368c. The commenter contends that much of the oil and gas production within the Uinta Basin occurs on Tribal lands within the Uintah and Ouray (U&O) Reservation and owned by the Ute Tribe. The commenter notes that, if the Tribe does not develop and submit an implementation plan to meet the EG OOOOc requirements, these Tribal lands will be subject to the EPA federal plan.

Commenter (2427-UPA) notes that the proposed EG OOOOc requires states and Tribes to submit a state plan for the EPA approval within 18 months of the date of publication of the final rule in the *Federal Register*. If the EPA does not develop its federal plan in a timely way, it will be difficult or impossible for operations on the Tribal lands to comply within the proposed timing, written as proposed and measured from the state plan submittal deadline. For example, the commenter states that it took the EPA nearly three years from proposal to final publication to develop the U&O FIP, a shorter and less complex rule. They add that it took the EPA nearly twice as long to develop the U&O FIP than the 18 months proposed for states and Tribes to develop their individual plans. The commenter suggests that, if the EPA needs similar time to develop the Federal plan for EG OOOOc as it used to develop the U&O FIP, this will severely cut into the compliance time. According to the commenter, with a shorter compliance time, operators may not be able to comply timely, and could potentially be forced to shut in wells until they can install the required equipment. The commenter believes that this scenario would result in a disproportionate impact on the Ute Tribe.

Thus, the commenter (2427-UPA) recommends that, for areas subject to the Federal plan, the final EG OOOOc should allow 36 months from the effective date of the Federal plan for compliance implementation. The commenter contends that anything less than that will have a disproportionate negative effect on operations on Tribal lands and on the Ute Tribe

Response II-19-57: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble.



Comment: Commenter (2193-CARB) states that the EPA assumes that California and Colorado have requirements at least as stringent as those in the proposed rule for many of the sources covered by the supplemental proposal. However, the commenter notes that the "presumptive standards" as outlined in the December 2022 supplemental proposed rule are not in alignment with California's requirements. These "presumptive standards" include numerous variables based upon the designated facility type, whether a particular type of alternative testing is approved, and ambiguity in the super emitter program that the commenter states may require California to enact numerous regulations and therefore not be able to meet an 18-month CAA section 111(d) Plan deadline. The commenter adds that the facility designation itself makes it extremely problematic for a state to draft and implement any proposed CAA section 111(d) Plan given it must determine whether it would classify under the "two or more" heading or the "centralized production" heading or whether it has compressor stations, whether the optional periodic screening may apply, or any other such variables just to analyze which testing methods are required. The commenter suggests that facilities themselves are likely to dispute their classification, making implementation and enforcement plans even more difficult when drafting the CAA section 111(d) Plan. Furthermore, the commenter provides that the proposed December 2022 supplemental rule requires that any state plan that includes RUOF for a less stringent standard to apply for a particular facility go through the public comment and community stakeholder engagement process as well.<sup>172</sup>

The commenter (2193-CARB) believes states will need more than 18 months to comply, with the possibility of significantly more time should any issues of equivalency determinations arise. For instance, additional regulations would delay California's time in issuing a 111(d) Plan by at least six months to 24 months total. In the event California does not need to adopt any additional regulations to comply with the December 2022 supplemental proposed rule, an 18-month deadline is possible. However, the commenter requests that EPA include a consideration in this deadline allowing states sufficient time to take regulations through the administrative process in the event their rules are not at least as stringent as those in the new December 2022 supplemental proposed rule.

The commenter (2193-CARB) also strongly encourages the EPA to streamline Leak Detection and Repair (LDAR) requirements in favor of a more uniform approach, include all approved advanced technologies in the Emissions Measurement Center website, and administer the super emitter program, to ensure states can complete their CAA section 111(d) Plans in a timelier manner.

Response II-19-58: Please see the discussion and response to comments on the timing of state plan submittals in section XIII.E. of the final preamble. Please see the discussion in section XI.B. with regards to EPA's final provisions for allowing advanced methane detections work practice.

#### ***19.6.4 36-Month Compliance Timeframe Concerns***

Comment: Several commenters (2288-NDDEQ, 2237-NDIC, 2296-NMED, 2403-PAO, 2423-Coterra Energy) express concerns with the 36-month compliance timeframe and state that adequate implementation time is needed to accomplish successful emission reductions.

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<sup>172</sup> Id.

Commenter (2423-Coterra Energy) notes that the EPA's proposed rules for new, modified, and reconstructed facilities are complex, far reaching and will affect tens of thousands of facilities. The commenter explains that the proposed EGs for existing sources will further dramatically expand the number of affected facilities. These new requirements will require oil and gas operators across the country to take numerous actions regarding equipment. They provide that constraints on supplies of compliant pneumatic controllers and pneumatic pumps are a particular concern. The commenter notes that the oil and gas industry certainly is not the only industry experiencing these supply chain issues; it is an economy-wide problem. Nevertheless, the commenter believes that the scope and breadth of these new rules will exacerbate existing delays in acquiring equipment on this scale. The commenter asserts that it is imperative that the EPA take these challenges into account before finalizing those provisions in the proposed rules that will mandate acquisition of new equipment.

The commenter (2423-Coterra Energy) further notes that the cumulative burden of new regulations supports the need for additional time for implementation. The commenter encourages the EPA to consider several factors in deciding on implementation timelines. The interrelationship of NSPSs OOOO, OOOOa, and OOOOb; and EG OOOOc are far from clear as other stakeholders make clear in their comments. For example, they suggest that it is unclear when NSPS OOOOa sources become subject to EG OOOOc. Further, an unprecedented number of sources will be subject to the rule. They add that supply chain delays will only further complicate implementation of these new requirements.

Commenter (2403-PAO, 2446-IPAA) recommends that the EPA set the compliance date with new state regulations for existing sources based on the approval of the state plans rather than their submission date. The commenter explains that, since states and the regulated community will not know if the state regulations will be approved or whether the EPA will be proposing a federal plan until the EPA acts, compliance should be based on final EPA action.

Commenters (2288-NDDEQ, 2237-NDIC) urge EPA to provide adequate time for states to meaningfully consider EPA final action and develop a state plan accordingly. Especially due to the lack of additional funding, the commenters believe that no less than 36-months should be allotted to states for plan development and submission. The commenters assert that this will allow states to fully consider the final EG OOOOc language and properly determine the best implementation for the state, especially when considering how best to account for items such as remaining useful life. The commenters add that continuing with the currently proposed 18-month deadline will likely result in inadequate and incomplete state plans, similar to what the U.S. has experienced with EPA's inadequate NSPS OOOO and NSPS OOOOa regulations. The commenters contend that these recent regulations were not well vetted since NSPS OOOOb is newly proposed and EG OOOOc will retroactively 'correct' errors, inconsistencies, and items overlooked under NSPS OOOO/OOOOa. Of note, the commenters believe that this issue could have been avoided altogether if EPA had meaningfully engaged with oil and gas producing states as EPA developed these regulations. The commenters assert that while meaningful engagement, in this context, should have happened between North Dakota (and other oil and gas states) and EPA, it did not happen and resulted in poor regulations [or half-baked regulations].

Response II-19-59: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

Comment: Commenter (2304-PIOGA) states that conventional operators and Pennsylvania Department of Environmental Protection (PADEP) are ill-equipped to comply with the proposed EG OOOOc. While the commenter understands that the compliance deadline for existing sources subject to EG OOOOc is years away, the commenter is not confident that the industry and the regulatory structure will be prepared to comply. According to the commenter, without any apparent concern for state regulators, the EPA is proposing in the December 2022 supplemental proposal a regulatory program dependent on component counts, which is not something either PADEP or existing sources have tracked or the basis for a regulatory framework. The commenter reports that industry already experiences difficulties with getting permits from PADEP in a timely manner. The commenter explains that the December 2022 supplemental proposal will bring thousands, if not tens of thousands, of sources under PADEP's regulatory authority. The commenter states that the PADEP does not have the work force to address that additional responsibility. The commenter adds that the PADEP's typical response to a shortage of people to do the work is to increase permitting fees – placing additional financial burdens on the sources least capable of absorbing the additional costs. The commenter notes that these additional costs on owners/operators of conventional wells is not at all accounted for in the EPA's BSER analysis.

Response II-19-60: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

#### ***19.6.5 36-Month Compliance Timeframe is Too Much Time***

Comment: One commenter (1659-CRP-PSPA) states that they urge the EPA to reconsider this timeline. The fact that designed facilities require more time to fix their polluting infrastructure should not be a burden that the public must be forced to endure and suffer. They urge the EPA to require a rapid review process and prioritization for states with higher methane emissions from designated facilities, such as Pennsylvania.

Response II-19-61: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

Comment: Several commenters (2028-WMCG, 2284-Kairos, 2392-Earthjustice et al, 2410-CA AG et al, 2433-EDF et al) suggest that for standards that do not require the installation of new equipment the compliance timeline should be accelerated. Commenters specifically note affected facilities other than oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps such as alternative leak detection programs. According to commenters, LDAR programs and alternative leak detection programs can be implemented relatively quickly and inexpensively compared to equipment retrofits. According to commenter (2410-CA AG et al), the EPA has failed to justify why such a lengthy compliance period would be necessary for these types of sources. The commenter adds that the desire to simplify compliance and ease the burden on industry operators is not a valid basis for this time frame under the statute and not warranted by these circumstances. These standards do not require changes to pneumatics devices or

installation of storage tank controls, system shutdowns or equipment purchases that could be impacted by supply chain shortages and delays. The commenters suggest a timeline for compliance for these facilities of no more than six months to one year after the EPA's approval of a state plan.

Commenter (2284-Kairos) note the advantages of phasing-in leak detection programs for EG OOOOc include owners and operators being provided with both an emissions reduction and economic benefit, alleviation of administrative burden and potential justification to allow more relaxed phase-in timelines in other areas where it may be necessary to minimize industry burden.

Commenters (2028-WMCG, 2284-Kairos) recommend that EPA consider incentivizing a separate, earlier phase-in period for control strategies that do not involve significant capital expenditures or retrofits. Commenter (2284-Kairos) suggests that this could be used to balance emissions from areas of the rule that may require additional time to implement.

Commenters (2392-Earthjustice et al, 2433-EDF et al) indicate that the EPA should further consider accelerated timelines for sources that require equipment replacement. Commenter (2433-EDF) suggests that the EPA consider adopting a shorter timeline such as 24 to 30 months after plan submission deadlines for sources that do require capital expenditures for compliance.

Commenter (2392-Earthjustice et al) suggests the EPA remove proposed provisions that allow existing sources to avoid compliance with the agency's proposed EGs based on RULOF exemptions.

Response II-19-62: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

Comment: Commenter (2343-NYU School of Law) recommends that the EPA reconsider whether to accelerate the timeline for compliance with state plans for select performance standards. The commenter notes that the EPA should reconsider whether the benefits of the proposed three-year uniform deadline may be overstated and whether the urgency of the health and environmental harms that state plans will address merits a shorter deadline for compliance to increase net benefits for society. According to the commenter, the EPA has given some consideration to the need for speed but given the December 2022 supplemental proposal's significant health and environmental benefits, the EPA should reevaluate the feasibility of a more aggressive compliance schedule that would allow these benefits to be realized sooner.

The commenter (2343-NYU School of Law) recommends that to select which standards of performance merit an earlier compliance deadline, the EPA should apply the nine factors that it identified for this very purpose in the December 2022 supplemental proposal (e.g., supply-chain issues). However, in lieu of the existing second and ninth factors ("[t]he cost of equipment" and "overall methane emissions reduction that will result from control of existing sources under the [emissions guideline]"), the commenter suggests that it would be preferable to examine net benefits. Compared to methane emissions reductions alone, looking to net benefits would allow for consideration of all relevant costs and benefits—including benefits from methane's co-

emissions—when evaluating whether to prioritize compliance with one standard of performance over another.

The commenter (2343-NYU School of Law) continues that, the nine factors indicate that the EPA should substantially shorten the timeline for existing sources to comply with the super-emitter response program. The EPA’s concerns about the costs of simultaneous implementation across the sector and planning burdens do not apply to this program. For the same reasons that 14 days is too long to wait before acting on a single super-emitter event, the commenter states that three years is too long to wait for the entire program.

The commenter (2343-NYU School of Law) suggests that in instances where the EPA has differentiated between subcategories of affected facilities, the EPA should further consider accelerating compliance for select subcategories if doing so appears more net beneficial than subjecting all designated facilities to the same deadline. The commenter provides that staggering compliance across tiers within a single EG could reduce the planning burden on entities in a given year and help prevent bottlenecks for specialized equipment and services by spreading compliance deadlines out over time.

For instance, the commenter (2343-NYU School of Law) points out the consideration of fugitive emissions at wells, a category that the EPA already divides into four tiers with different monitoring requirements based on the number of wells at the site and the presence of major equipment. The commenter states that EPA could apply the same nine factors discussed above to designate one or more tiers of wells subject to an accelerated compliance timeline. The commenter adds that the EPA could conduct a similar assessment for its four potential subcategories for pneumatic controllers (well sites, gathering and boosting stations, transmission and storage compressor stations, and natural gas processing plants).

The commenter (2343-NYU School of Law) notes that this tiering of compliance deadlines may increase net benefits relative to waiting three years for all four tiers because a subset of the December 2022 supplemental proposal’s benefits would be achieved sooner and thus accrue over the additional time. While annual costs would also accrue over the additional time, the commenter believes that the benefits would most likely exceed the costs to the same extent as they are projected to do so for future years.

Response II-19-63: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

#### ***19.6.6 Conflicting Timelines***

Comment: Commenter (2220-WDEQ) brings to the EPA’s attention potential conflicting requirements in the supplemental proposal and the EPA’s proposed rule for *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)*, and potentially other regulations.

The commenter (2220-WDEQ) notes that the revised deadline in 40 CFR part 60 subpart Ba 40 CFR 60.23a (“Adoption and submittal of State plans; public hearings”), reduced from three years

to 15 months, conflicts with the 18-month State Plan deadline specified in the proposed regulatory text for EG OOOOc. While the commenter acknowledges the EPA’s statement “unless otherwise specified in the applicable subpart,” they are concerned that the 18-month proposed deadline for submitting State Plans could be altered to the 15-month deadline specified in the proposed revisions to Subpart Ba once both proposed rules are finalized. As noted in other comments provided the commenter already considers an 18-month deadline to be impracticable; and a 15-month timeframe would set an entirely impossible bar for state agencies to attempt to hurdle.

Additionally, the commenter (2220-WDEQ) notes that there are numerous other areas in which the supplemental proposal may have overlapping impacts with another proposed federal rule: BLM’s *Waste Prevention, Production Subject to Royalties, and Resource Conservation* proposed rule. The commenter agrees with and supports the comments of the Wyoming Oil and Gas Conservation Commission (WOGCC) related to the specific overlapping requirements. The commenter asserts that it is important that the EPA thoroughly reviews the supplemental proposal and other proposed and existing regulations and make corrections that ensure there are no conflicting technical or implementation requirements in the final rules.

Response II-19-64: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble. The EPA notes that the BLM rulemaking is not yet final.

### ***19.6.7 Other Plan Submission and Compliance Timeline Considerations***

#### **19.6.7.1 Timelines for State Plan Submission and Compliance**

Comment: Several commenters (2237-NDIC, 2249-NACAA, 2293-Holmes, 2301-US CoC, 2427-UPA, 2502-RGISC) provide comments for EPA to consider when establishing the timelines for state plan submission and compliance.

Commenters (2237-NDIC, 2249-NACAA) request that EPA provide adequate timelines to meaningfully consider EPA’s final action, develop and implement state plans.

Commenter (2249-NACAA) recommends that EPA engage with agencies to determine whether proposed timelines offer sufficient time for administrative rulemaking and meaningful public engagement. The commenter also recommends that EPA provide clear guidance in the determination of when a plan becomes applicable.

The commenter (2249-NACAA) notes that the separately proposed CAA section 111 implementation rule published in the *Federal Register*<sup>173</sup> by EPA on December 23, 2022, changes the deadline for the provision of plans, shortening the time to submit a state plan under CAA section 111 to EPA from 3 years to 15 months. The proposed December 2022 supplemental rule also reflects a shortened compliance window, in this case to 18 months. The

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<sup>173</sup> (“Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111[d]”, 87 Fed. Reg. 79176) Online at <https://www.federalregister.gov/documents/2022/12/23/2022-27557/adoption-and-submittal-of-state-plans-for-designated-facilities-implementing-regulations-under-clean>.

commenter states that for more complex requirements under CAA section 111 that would fall under the proposed December 23, 2022, implementing regulations for which EPA does not provide model rules, more time may be needed to develop the required state plan.

The commenter (2249-NACAA) states that EPA's proposed December 2022 supplemental rule also creates changes in the determination of when a plan becomes applicable. The commenter notes that regulations under Subpart B determined that a plan came into effect once approved by EPA; the proposed supplemental determines that applicability begins when a plan is proposed by the state agency. The commenter believes that this will create confusion and regulatory uncertainty under a hypothetical circumstance where a state plan is subsequently disapproved by EPA.

Commenter (2301-US CoC) notes that these burdens and implementation timeline can be reduced by allowing states to rely on existing state regimes to limit the amount of change in regulatory requirements that both the state regulators and regulated industry will face. As a result, they suggest that it may be feasible to shorten the implementation timelines if the EPA provides sufficient flexibility to the states to use existing regimes.

Commenter (2427-UPA) states that any shortening of the timing in the final rule could result in significant implementation problems and possible need to shut in wells until equipment can be procured and installed. Shutting in wells could lead to energy shortages and consumer price escalation nationwide. The commenter also recommends inclusion of a provision for case-by-case extensions. This would provide a backstop should unforeseen problems create more difficulties with labor or supply chains. Case-by-case extensions could be modeled after those provided in the U&O FIP in 40 CFR Part 49 §49.4169(c).

Response II-19-65: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

#### 19.6.7.1 Accelerated Schedule Pathway

Comment: Commenter (2433-EDF et al) encourages the EPA to consider providing an additional pathway for states that would like accelerated submission and consideration of state plans, or alternatively an accelerated FIP schedule for states that choose at the outset not to submit a plan. The commenter believes that this would ensure that states have in place enforceable emission limits for existing sources as early as 2024.

Commenter (2270-Private Citizen) supports the reduction of methane emissions but contends that the implementation and enforcement process does not address the urgency needed to address climate change under the currently proposed timeline. The commenter notes that the EPA's current timeline indicates that states and industry must comply with these new requirements by 2028. The commenter asserts that is not sufficient, even assuming there is 100% compliance.

Commenter (2356-Earthworks et al.) urges the EPA to move as quickly as possible to implement and finalize these rules. The commenter states that communities and the climate are being harmed right now. According to the commenter, it is critical that EPA moves quickly to finalize

national rules. Once the ink dries and these rules are enacted, states must quickly work to write SIPs to show how they will implement and enforce new federal standards on the ground. In cases where a SIP falls short of meeting federal standards, the EPA must swiftly issue a FIP to eliminate industry self-policing and regulatory capture.

Response II-19-66: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

#### 19.6.7.2 Alignment with of State/Tribal/Federal Plans

Comment: Commenter (2177-Ute Indian Tribe) states that for development of any deadlines for state or tribal plans, the EPA should also consider deadlines for federal plans and align these deadlines. There should not be a difference in the deadlines for implementation and compliance with FIP/SIP/TIP. This ensures an equitable and level regulatory playing field for all areas.

Response II-19-67: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble.

#### 19.6.7.3 Methane Emissions Reduction Program (MERP)

Comment: Commenter (2301-US CoC) states that the Methane Proposal would require states to submit their compliance plans within 18 months after final publication of the EGs. The commenter notes that the EPA states that this deadline is consistent with the requirement of CAA section 111(d) that the EPA promulgate procedures “similar” to CAA section 110 and the D.C. Circuit’s directive to “engage meaningfully with the different scale” of the CAA section 111(d) and 110 plans, while also considering impacts to public health and welfare. Ahead of this deadline, the commenter recommends that the EPA work closely with the states and Tribes on an expedient approval process in recognition that this will provide much-needed regulatory certainty for the industry and in recognition that the IRA allows for exemptions from the newly introduced methane emissions charges under the MERP—which will soon take effect in 2025—if the EPA regulations addressing methane emissions (1) are in effect in all states, and (2) will “result in equivalent or greater emissions reductions as would be achieved” by the November 2021 Notice. Given the substantial potential costs of the methane emissions charges, the commenter urges the EPA to take the MERP exemption deadline into consideration in its approval process and encourages the EPA to work both internally and with state and tribal regulators to ensure a smooth and efficient process. The commenter contends that doing so will effectuate congressional intent behind the MERP and promote regulatory clarity for the entire sector.

Response II-19-68: Please see the discussion and response to comments on the compliance timeline in section XIII.E. of the final preamble. EPA notes that the implementing framework for the MERP is being addressed in separate EPA actions outside the scope of this rulemaking.



### ***19.6.8 Federal/Tribal Plans***

Comment: Commenter (2222-WDNR) provides that the EPA notes concern in the December 2022 supplemental proposal about achieving emissions reductions quickly to produce necessary climate and air quality benefits. Understanding it will be infeasible for some states to submit an approvable state plan on timelines identified in this rule, the commenter suggests that the EPA could preemptively address this concern by proposing and finalizing a federal plan expeditiously.

Response II-19-69: Please see the discussion and response to comments on the compliance timeline in section XIII.F. of the final preamble.

Comment: Commenter (2181-Ute Indian Tribe) recommends that EPA consider developing reservation specific FIP or assist tribes with developing Tribal Implementation Plan (TIP) for sources located within Indian country. The commenter recommends that EPA consider the timeliness of FIP and/or TIP development to coincide with state plans.

The commenter (2181-Ute Indian Tribe) states that the proposed regulations do not directly impose requirements on existing sources. Rather, states must submit plans for the EPA's approval that are at least as effective as the presumptive standards in EG OOOOc. The commenter notes that many states already have oil and gas emission control programs in place, and the EPA has outlined criteria to assist those states in determining whether those existing programs are equivalent to EG OOOOc. The commenter contends that this approach leaves sources located in Indian country in uncertainty as sources in Indian country are not under state regulation.

Response II-19-70: Please see the discussion and response to comments on the compliance timeline in section XIII.F. of the final preamble.

### ***19.6.9 EPA's Administration Deadlines***

Comment: Commenter (2326-AXPC) states that as a preliminary matter, they acknowledge that the EPA in the December 2022 supplemental proposal did not propose deadlines for the EPA's own functions as part of the CAA section 111(b) existing-source regulatory process.<sup>174</sup> They intend to submit comments on the EPA's separate proposal, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)*, 87 Fed. Reg. 79,176 (Dec. 23, 2022), whose comment period closes on February 27, 2023, in which we will address the EPA's proposed deadlines.

However, because, reading the terms of the two proposals together, the commenter (2326-AXPC) states that some of the deadlines proposed in that separate proposed revision to the "implementing regulations" generally governing the EPA's administration of the existing-source program will apply to proposed new EG OOOOc, they are presenting their observations,

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<sup>174</sup> See 87 Fed. Reg. at 74,831-33.

concerns, and suggestions on the proposed deadlines under that action as part of their comments as well.

The commenter (2326-AXPC) does not believe that the EPA will delay its ability to make determinations that the conditions for exemptions from the methane fee program under the IRA are met by providing itself sufficient time to make completeness determinations and approve state programs under EG OOOOc.

The commenter (2326-AXPC) notes that their comments here are directed to the EPA's intention to apply certain deadlines proposed in the "implementing regulations" proposal to EG OOOOc.<sup>175</sup> Due to the overlapping comment periods and the interrelated nature of the two proposals, the commenter feels it is better to file partially redundant comments on the two proposals rather than risk raising the comments in an incorrect forum.

The commenter's (2326-AXPC) general observation on the EPA's proposed deadlines is that, when the EPA imposes deadlines on itself to perform functions to which Congress assigned no statutory deadline, the EPA is creating new obligations on itself which are potentially enforceable under "deadline" suits brought by outside parties under CAA section 304.<sup>176</sup>

If the EPA imposes deadlines on itself that are not long enough, the commenter (2326-AXPC) states that it runs the risk of the timing and prioritization of its tasks being set not by itself or by Congressional direction, but rather by litigation brought by outside interest groups. The commenter explains that the experience of the NAAQS program and its associated state- and federal-planning process, replete with statutory deadlines as it is, is a cautionary example: where deadlines cluster, and where the EPA has to respond to many state submissions subject to those deadlines, or take state-by-state action on its own subject to other deadlines, many or most deadlines will not be met in the first instance, will be subject to "deadline suit" litigation, and will end up with new deadlines imposed via settlement or court order – often out of control of the EPA and the states, or at a faster pace than is appropriate.

The commenter (2326-AXPC) notes that this familiar scenario in cases where Congress *has* imposed statutory deadlines is more reason for the EPA to ensure that it gives itself adequate time when selecting deadlines of its own choosing. This concern is especially pressing in this rulemaking, which will initiate the most complicated existing-source implementation process the EPA has yet managed in over 50 years of administering the CAA, with most if not all states containing jurisdictional existing sources requiring a CAA section 111(d) plan, and many states containing an unusually high number (thousands or more) of existing sources that are unusually complex and variegated—as the EPA forthrightly acknowledges in the Supplemental Proposal.<sup>177</sup>

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<sup>175</sup> [See *id.*] (EPA intends to apply some deadlines proposed in the separate "implementing regulations" proposal to Subpart OOOOc and intends to finalize the "implementing regulations" proposal "not later than" it finalizes Subpart OOOOc).

<sup>176</sup> [See, e.g., *California v. EPA*,] 360 F. Supp. 3d 984, 991 (N.D. Cal. 2018) (Congress intended in Section 304 "to waive sovereign immunity for the EPA's failure to perform nondiscretionary duties mandated by regulations").

<sup>177</sup> See generally, 87 Fed. Reg. at 74,832-34.

The commenter (2326-AXPC) recommends that EPA finalize a mechanism under which a state can ask for and receive an extension of their submittal deadline if the state demonstrates to the Administrator that its situation is sufficiently complex or otherwise unique that the general assumptions, findings, or rationale underlying the deadlines that the EPA does finalize do not apply in its case. The commenter adds that EPA should also consider finalizing such a mechanism to provide itself with an extension for its own deadlines to make completeness determinations, decisions to approve or disapprove submitted state plans, and to issue federal plans where special circumstances warrant. However, they suggest that these extension mechanisms would not be advisable if they required an additional round of notice-and-comment rulemaking, as that would divert additional the EPA resources from working with states on their plan development, submittal, review, and approval.

If the EPA does not adopt this type of extension mechanism, the commenter (2326-AXPC) recommends the following specific changes to the deadlines proposed at 87 Fed. Reg. 79,182, Table 1 as they will apply to final EG OOOOc:

- Where the EPA proposes two months for the EPA to determine whether a state plan submittal is complete, the commenter urges the agency to provide itself with no less than four months. Two months is an unusually short deadline in the context of the complexity of the task before the EPA and the high number of state plan submittals the EPA is likely to receive – all likely clustered around the deadline for submission of such plans. The proposed two-month deadline is particularly likely to create a “logjam” scenario of missed deadlines at the outset of the state-plan review process, accompanied by a heightened risk of diversion of resources to “deadline suits” as described above.
- Where the EPA proposes 12 months for the EPA to issue a federal plan after disapproving a state plan or determining that a state has failed to submit a complete plan, the commenter urges the agency to provide itself with no less than 18 months. The EPA should give itself at least as much time to draw up its plan as it’s giving the states to draw up their plans. The December 2022 supplemental proposal explicitly states: “18 months is the minimum period of time in which the EPA finds that most states can expeditiously create and submit a plan that meets applicable requirements for EG OOOOc.”<sup>178</sup> For the same reason, the EPA should provide itself with at least that same period of time. The EPA indeed may wish to consider providing itself with more time than it provides the states, given that the states as local and primary regulators are presumably more familiar with the characteristics of their existing-source fleets than is the EPA as a general, federal regulator.

Response II-19-71: Please see the discussion and response to comments on the timelines applicable to EPA action in section XIII.F. of the final preamble.

## **19.7 State Implementation Resources**

Comment: Commenters (2218-TCEQ, 2222-WDNR) request that EPA provide additional resources (e.g., guidance, tools, templates) to assist states and local air agencies to adequately

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<sup>178</sup> Id. at 74,834.

develop and implement the requirements of EG OOOOc (and NSPS OOOOb). Examples of some of the comments provided are presented in the following paragraphs.

Commenter (2218-TCEQ) requests that additional resources be made available to states and regulatory authorities to assist with implementation and enforcement of NSPS OOOOb and EG OOOOc. The commenter asserts that guidance documents, workbooks, reporting forms, templates, flow charts, video tutorials, and other resources would greatly benefit the delegated administrator in implementation of the new monitoring, recordkeeping, and reporting requirements contained within the rules. The commenter also requests that a guidance document, similar to the small business compliance guide for NSPS OOOOa, be developed and provided as a tool to help the regulated community understand the complex regulatory requirements. The commenter requests that a guidance document be available to assist regulated entities with submitting required notifications, data, reports, and approval requests. The commenter suggests that guidance should address where and to whom the relevant reports or notifications should be submitted and provide information summarizing deadlines or schedules for each type of report or notification. The commenter also requests that a template be available for regulated entities to use to assist in providing required information where applicable.

Commenter (2222-WDNR) requests that EPA provide resources to state and local agencies for the development of construction and operating permits as well as resources to support agencies' compliance assistance programs. The commenter asserts that the proposed rule would add to the number of permitted facilities and to the complexity of rules included in the permits. The commenter states that the proposed rule would result in an influx of permit applications from sources seeking to install additional combustion equipment to control emissions, and site-specific monitoring plans that must be reviewed, approved, and correctly incorporated into operating permits through permit revisions.

Commenter (2247-Ohio Environmental Protection Agency (Ohio EPA)) states each of the AVO reports will need to be submitted to Ohio EPA for review to determine the compliance status of the well operator and confirm that the AVO was completed and done correctly. Assuming the four required AVO inspections each year result in one annual AVO report, and it takes an hour to review each report, there would be 52,250 hours per year worth of work. That means Ohio EPA would have to hire 26 new employees just to review the AVO reports. If you add in the work needed to evaluate other reports that need to be submitted and the work needed for inspecting the facilities to ensure they are in compliance, then the number of employees could easily triple. This is a very large increase in workload for Ohio EPA. To hire these staff, the current air program at Ohio EPA does not have extra resources to apply to this endeavor and will need additional funding. EPA has not provided any recommendations for how states are to fund this additional work. EPA has also not provided a mechanism or funding stream that will be used to fund this work. It is incumbent on EPA to provide substantial more resources to the states to meet the increasing obligations placed on states by the federal government.

Response II-19-72: The EPA does intend on working with tribes and states to develop plans tailored to the factors concerning the states. The plan development process, under which performance standards for existing sources are established within their jurisdiction and have the discretion to consider remaining useful life and other factors, is one that Congress established

through the text and structure of CAA section 111(d). See discussions in section V.B.2.<sup>179</sup> and section V.B.3.<sup>180</sup> of the December 2022 Supplemental and section XIII of the final preamble and final rule, Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) at 88 FR 80480, November 17, 2023, and its corresponding Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

The new standards will work hand-in-hand with new resources and programs in the Inflation Reduction Act, which will incentivize early implementation of innovative methane reduction technologies and support methane mitigation and monitoring activities. These efforts will achieve greater methane emissions reductions more quickly. For more information on the IRA, the Administration has created a guidebook that provides an overview of the clean energy, climate mitigation and resilience, agriculture, and conservation-related tax incentives and investment programs, including who is eligible to apply for funding and for what activities. See <https://www.whitehouse.gov/cleanenergy/inflation-reduction-act-guidebook/>.

## **19.8 EPA State Plan Approval Authority**

### ***19.8.1 “Satisfactory” State Plan Approval***

Comment: Commenter (2252-PAW) expresses concern with EPA’s attempt to set an unrealistic bar within its authority to ensure state plans are satisfactory. The commenter states that the CAA gives EPA authority to review states plans to ensure they are “satisfactory”. The commenter notes that in crafting a presumptive standard for existing sources, EPA is asserting that only state plans achieving equal to or greater emission reductions than what EPA has proposed will be approved. The commenter reports that synonyms for satisfactory include adequate, good enough or fine. Instead, the EPA is setting a bar of requiring state plans be exemplary, flawless, or perfect, or face disapproval. The commenter contends that Congress intended plans to be satisfactory, which acknowledges that each state will come to varying conclusions about what is appropriate to require of existing sources. This is another area where the commenter believes that the EPA needs to revise its posture to that of what they assert Congress expressly provided.

Commenter (2428-API) urges EPA to provide more flexibility in approving state programs. The commenter highlights a flaw in EPA’s approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are “satisfactory.” CAA section 111(d)(2)(A). The commenter notes for example, that EPA explains that “it is the EPA’s responsibility to determine whether a state plan is “satisfactory”. EPA further explains that “the most reasonable interpretation of a “satisfactory plan” is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d).”

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<sup>179</sup> 87 FR 74812.

<sup>180</sup> 87 FR 74816.

The commenter (2428-API) contends that by EPA's reasoning, all elements of its CAA section 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, the commenter asserts that EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA section 111(d). In other words, the commenter notes that EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

The commenter (2428-API) believes that EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA section 111(d) programs. The commenter notes that the statute simply says that state plans must be "satisfactory." According to the commenter, the word "satisfactory" naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The commenter contends that the word "satisfactory" does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA's self-determined "health and welfare objectives") or to impose substantive constraints not otherwise specified by CAA section 111(d). The commenter states that EPA's effort to give more meaning to the word "satisfactory" is inconsistent with the law and a misplaced effort to expand the Agency's authority under CAA section 111(d).

Response II-19-73: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (2446-IPAA) questions EPA's use of a dated definition of "satisfactory". The commenter expresses concern with the substantial difference in definitions. The commenter assumes that EPA wants to establish a different standard to constrain the state flexibility that Congress chose to establish.

The commenter (2446-IPAA) asserts that there are several elements of the EPA proposal that are designed to maintain control by EPA and limit states. It begins with something as simple as the definition of "satisfactory" in the context of approving state plans that provide for less stringent regulations of sources based on Congress providing that:

Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

The commenter (2446-IPAA) provides that the EPA has characterized the authority to consider RULOF. As EPA notes: CAA section 111(d)(2)(A) authorizes the EPA to promulgate a Federal plan for any state that "fails to submit a satisfactory plan" establishing standards of performance

under CAA section 111(d)(1). Accordingly, the EPA interprets "satisfactory" as the standard by which the EPA reviews state plan submissions. Consequently, EPA presents what the commenter believes is a strained assessment of the definition of "satisfactory":

Additionally, while states have discretion to consider RULOF under CAA section 111(d), it is the EPA's responsibility to determine whether a state plan is "satisfactory," which includes evaluating whether RULOF was appropriately considered. The relevant dictionary meaning of "satisfactory" is "fulfilling all demands or requirements." The American College Dictionary 1078 (C.L. Barnhart, ed. 1970). Thus, the most reasonable interpretation of a "satisfactory plan" is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d), including the provisions governing the application of RULOF.

The commenter (2446-IPAA) questions why EPA has chosen this particular 1970 dictionary as the relevant dictionary. The commenter notes that other contemporary dictionaries: such as the 1975 American Heritage Dictionary define "satisfactory" as "giving satisfaction; sufficient to meet a demand or requirement; adequate", the contemporary Merriam-Webster Online Dictionary definition is "adequate", and the Oxford American English Dictionary Online definition is "good enough for a particular purpose". The commenter contends that this substantial difference in definitions is intended because EPA wants to establish a different standard to constrain the state flexibility that Congress chose to establish. The commenter states that similar issues arise elsewhere in the CAA section 111(d) proposal.

Response II-19-74: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

### ***19.8.2 EPA State Plan Approval/Disapproval of Less Stringent Alternative Standards Based on RULOF Exceeds EPA's Authority***

Comment: Commenters (2218-TCEQ, 2292-WV AG et al, 2399-GPA) specifically highlight that they believe that the EPA is exceeding its statutory authority under CAA section 111(d) as it relates to EPA having the ability to approve/disapprove of alternative standards under a submitted state plan that are less stringent than EPA's proposed presumptive standards based on RULOF.

Commenter (2218-TCEQ) states that EPA is exceeding its authority under CAA section 111(d) with the proposed requirement in 40 CFR 60.5363c that standards of performance for designated facilities must be at least as protective as the EGs unless the EPA approves alternate standards under 40 CFR 60.5365c. Under proposed 40 CFR 60.5363c(a)(4), the EPA's proposed requirements for the state plan specify that the standards of performance included in the plan must be at least as protective as the EPA's EGs, unless the EPA approves alternative standards under 40 CFR 60.5365c. The proposed provisions under 40 CFR 60.5365c allow for the EPA to approve less stringent standards of performance. The commenter contends that EPA did not

explain in the preamble about the choice of wording in 40 CFR 60.5363c(a)(4). However, the commenter asserts that protectiveness and stringency are not necessarily equivalent. Further, the commenter asserts that 40 CFR 60.5365c(e)(1)(vii) requires that, if the less stringent standard is established based on remaining useful life, the increased emissions for the duration of the remaining useful life will not result in negative impacts to the surrounding communities, including those most affected by and vulnerable to the health and environmental impacts of the plan.

The commenter (2218-TCEQ) also notes that in the recently proposed revisions to the state plan implementation regulations in 40 CFR Part 60, Subpart Ba, EPA proposed to only require states, in calculating a less stringent standard, to consider the potential pollution impacts and benefits of control to communities most affected by and vulnerable to emissions from the designated facility. The preamble language associated with 40 CFR 60.5365c(e)(1)(vii) appears to mirror the language proposed with the implementation regulations, stating "...to the extent a designated facility would qualify for a less stringent standard through consideration of remaining useful life and other factors (RULOF), the state, in calculating such a standard, must consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions." However, the commenter notes that the rule language proposed in 40 CFR 60.5365c(e)(1)(vii) does not require consideration of impacts but actually prohibits a state from adopting a less stringent standard if there are negative impacts. Additionally, the commenter notes that the demonstration required to satisfy 40 CFR 60.5365c(e)(1)(vii) as proposed involves a health and environmental protectiveness evaluation of the local community around each specific facility where the state would consider establishing a less stringent standard. The commenter asserts that EPA did not evaluate protectiveness at a local level in establishing the proposed EGs to the degree that 40 CFR 60.5365c(e)(1)(vii) would require the state to demonstrate, as EPA acknowledges in the preamble. However, the commenter states that CAA section 111(d) does not specify the state plan be at least as protective.<sup>181</sup> The commenter believes that EPA is exceeding its authority by requiring protectiveness reviews if a state proposes less stringent standards for a facility that considers the facility's remaining useful life. Furthermore, the commenter believes that EPA is also holding the state to a standard of evaluation far beyond that used by the EPA when establishing the proposed emission guidelines. Further, the EPA has not defined negative impacts and, as written, the requirement appears to go beyond health and environmental factors, which could hold the state to evaluating impacts on factors beyond the state's authority to regulate.

Further, commenter (2218-TCEQ) asserts that this proposal prohibits many states from utilizing their statutorily given discretion and therefore impermissibly constrains state authority, rather than providing a regulatory scheme that allows states to adopt alternative standards based on RULOF.

The commenter (2218-TCEQ) contends that the state plan requirements proposed by EPA are so onerous and time-consuming as to eviscerate the authority given to states by Congress to consider RULOF in adopting alternative standards for certain sources. The commenter believes

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<sup>181</sup> See CAA section 111(d)(1) ("... Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.")



that the proposal will force states with large numbers of affected sources to adopt the model rule and eliminate the discretion provided in CAA section 111(d). The commenter asserts that EPA cannot take away through regulation authority given to states by Congress. CAA section 111(d) states in relevant part: “Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.” Proposed new 40 CFR 60.5365c requires states intending to apply a less stringent standard on a particular source due to RULOF to provide a multi-faceted demonstration of unreasonable cost, technical infeasibility, and other factors specific to the facility. The commenter contends that if the alternative standard is based on remaining useful life, several additional factors must be considered. For example, proposed 40 CFR 60.5365c(b)(1) requires the state to identify all available control technologies and evaluate each system using the same factors and metrics used by EPA. The commenter believes that states should not be required to evaluate control technology that EPA has previously excluded from the BSER based on technological or economic feasibility. The only control technologies that should be relevant to the determination under 40 CFR 60.5365c(b)(1) are control technologies that achieve less emission reductions than the technology determined by EPA to represent BSER. Further, the commenter asserts that requirement that states evaluate technologies using the same factors and metrics is unreasonable because the EPA has not disclosed all factors and metrics used in evaluating all technologies when it determined BSER. Additionally, as the commenter discussed previously, the EPA’s three requirement in 40 CFR 40 CFR 60.5365c(e)(1)(vii) concerning negative impacts would force states to perform protectiveness evaluations for any source that the state decides to set an alternate standard based on remaining useful life. Such evaluations could require extensive modeling to determine impacts for the proposed control level as well as EPA’s BSER control level. The commenter reports that Texas has a substantial number of oil and gas facilities with many that legitimately cannot cost-effectively or technically meet the applicable EGs because of their age, production capability, location, etc. If only a small fraction of these sources request or require an alternative standard demonstration, it will be virtually impossible to complete and timely submit a state plan while also meeting state rule development requirements and the additional “meaningful engagement” requirements imposed by this rule. According to the commenter, for states with considerable oil and gas development, the result will be adoption of the model rule with no opportunity for sources to receive an alternative standard based on RULOF, as the CAA allows. The commenter asserts that EPA’s state plan requirements for submitting plans and consideration of RULOF for certain sources is written in such a way that it does not actually “permit” states to do so in practice. Rather than providing a regulatory scheme that allows states to adopt alternative standards based on RULOF, this proposal prohibits many states from utilizing their statutorily given discretion and therefore impermissibly constrains state authority.<sup>182</sup>

Commenter (2292-WV AG et al) contends that the proposal appears to try to push states into abandoning their local-level discretion by saddling states with significant new obligations any time that discretion is employed. The commenter notes that CAA section 111(d) allows states to apply a more lenient standard by considering “among other factors, the remaining useful life of

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<sup>182</sup> See *American Corn Growers Assn. v. EPA*, 291 F3d. 1 (D.C. Cir.) (vacating an EPA rule in part because its requirements were “inconsistent with the Act’s provisions giving the states broad authority over [Best Available Retrofit Technology] determinations...”).

the existing source” for each facility.<sup>183</sup> The commenter contends that EPA traditionally interpreted this freedom to apply in three scenarios: (1) when the cost from plant age, location, or process design is unreasonable; (2) when there is a “physical impossibility of installing [the] necessary control equipment”; and (3) when other factors make a less stringent standard “significantly more reasonable.” Yet under the proposal, the commenter notes that states must offer EPA an extensive justification for using lower standards to reflect remaining useful life, sometimes calling for precision that may be impossible to achieve when talking about future events. Among other things, the commenter notes that states must now show how their systems are “fundamentally different” than EPA contemplated before invoking their statutorily guaranteed discretion to consider remaining useful life. Further, the collection of specific requirements for invoking that factor—which includes contingencies, restrictive cost considerations, and impacted-communities analysis narrows the “range of permissible choices to the [s]tates” from that which Congress determined was appropriate.<sup>184</sup> For instance, the commenter states that no reasonable justification exists for limiting a state’s cost considerations to capital expenditures alone.

In effect, the commenter (2292-WV AG et al) asserts that the proposed rule replaces the state “laborator[ies]” for regulating methane at existing sources with one national administrative setup.<sup>185</sup> The commenter states that EPA admits as much. The commenter reports that EPA complains that under the current scheme, “two states could consider [remaining useful life] for two identically situated designated facilities and apply completely different standards of performance.” The commenter contends that is precisely what cooperative federalism permits, because California and West Virginia may (and do) view the collective impact from cost, structure, or other factors on a source’s remaining useful life differently. These different views may derive, for instance, from the different composition of a particular state’s energy portfolio—and may lead to equally good air quality across the board. The commenter asserts that Congress invited this state-by-state variation, and EPA cannot contradict what Congress made clear in statute.<sup>186</sup> The commenter states that CAA section 111(d) entrusts states to use standards that are more lenient on certain sources because of—among other discretionary factors—remaining useful life.<sup>187</sup>

Commenter (2399-GPA) asserts that EPA lacks authority to impose conditions on states’ use of RULOF. The commenter argues that the “standards of performance” interpretation is unreasonable, and impermissible. Support for their position is provided in the following paragraphs.

*The Supplemental Proposed Rule’s “Satisfactory Plan” Interpretation is Contradicted by the Statute and is Unreasonable.* The commenter (2399-GPA) contends that in support of its proposal, EPA relies on an erroneous interpretation of CAA section 111(d), as EPA would substantially alter the roles of EPA and the states established by statute’s text and structure and recognized by the D.C. Circuit, based on a strained and implausible reading of CAA section

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<sup>183</sup> 42 U.S.C. § 7411(d).

<sup>184</sup> *Wis. Dep’t of Health & Fam. Servs. v. Blumer*, 534 U.S. 473, 495 (2002).

<sup>185</sup> *New State Ice Co. v. Liebmann*, 285 U.S. 262, 311 (1932) (Brandeis, J., dissenting).

<sup>186</sup> *Nat’l Ass’n of Home Builders v. Defs. of Wildlife*, 551 U.S. 644, 665 (2007).

<sup>187</sup> 42 U.S.C. § 7411(d).

111(d)(2)(A). The commenter notes that sub-section governs federal implementation plans promulgated where a “[s]tate fails to submit a satisfactory plan” as the Administrator “would have under section 7410(c) of this title in the case of failure to submit an implementation plan.” Instead of naturally interpreting this sub-section as providing EPA with the authority to issue federal emission standards for existing sources whenever a state either fails to submit a plan or the plan is disapproved (a reading that tracks the referenced Section 7410(c)), the commenter notes that EPA proposes to read the term as giving it a superpower to limit the states’ authority in the first place. According to EPA, the phrase “satisfactory plan” grants EPA vast and unprecedented powers to impose extensive conditions that restrict how states establish existing source emission limitations. According to the December 2022 supplemental proposed rule, “the most reasonable interpretation of a ‘satisfactory plan’ is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d), including the provisions governing the application of RULOF.” The commenter contends that this interpretation violates several basic rules of statutory construction and is, therefore, not a reasonable (or even permissible) reading of Section 111.

To begin, commenter (2399-GPA) suggests that the EPA’s interpretation merely begs the question. It declares that EPA has the authority to regulate a state’s use of RULOF because a “satisfactory plan” must comply with EPA regulations governing a states’ use of RULOF. Thus, the commenter believes that the December 2022 supplemental proposal presupposes an authority to regulate the states without actually trying to find such an authority in CAA section 111(d)(1) – an impossible task, given the subsection’s text and structure, as well as the D.C. Circuit’s ruling.

Further, the commenter (2399-GPA) asserts that EPA’s “satisfactory plan” interpretation violates basic principles of statutory construction. Thus, the commenter states that it is not a reasonable construction of CAA section 111(d)(1) and will warrant no deference in court.<sup>188</sup> For instance, the commenter notes that the interpretation reads the following statutory terms out of the text:

- Under CAA section 111(d)(1), the Administrator is limited to “prescrib[ing] regulations which shall establish a procedure similar to that provided by Section 7410 of this title.” Under the “satisfactory plan” interpretation, the Administrator would have virtually unlimited substantive powers to establish existing source standards of performance by prohibiting states from exercising their own discretion, not the mere power to “establish a procedure.”
- Under CAA section 111(d)(1), “each state,” not EPA, “establishes standards of performance for any existing source for any air pollutant.” Under the “satisfactory plan” interpretation, EPA would dictate how standards of performance for existing sources would be established, not States.
- Under CAA section 111(d)(1), “the state,” not EPA, “take[s] into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.” Under the “satisfactory plan” interpretation, the states’ “consideration” of RULOF would be so circumscribed by EPA as to become a mere mechanical exercise of endorsing EPA’s emission guidelines.

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<sup>188</sup> See *Chevron USA Inc. v. NRDC, Inc.*, 467 U.S. 837, 844 (1984) (courts will only defer to “a reasonable interpretation made by the administrator of an agency”).

- Under CAA section 111(d)(2), EPA only has the authority described in Section 7410(c). That section allows for a FIP when a SIP is disapproved for a failure to comply with the statutory requirements of section 7410(k)(1)(A). Nothing in section 7410(c) provides EPA with authority to create new standards with which a state plan must comply. Under the “satisfactory plan” interpretation, Congress’ cross-reference to section 7410(c) would be meaningless and the sub-section’s language would effectively terminate after the phrase “fails to submit a satisfactory plan.”

In fact, the commenter (2399-GPA) states that EPA’s “satisfactory plan” interpretation improperly re-writes CAA section 111(d) as to render the majority of CAA section 111(d)(1)’s text, and half of CAA section 111(d)(2)(A)’s text, superfluous.<sup>189</sup> The commenter contends that the December 2022 supplemental proposed rule’s “satisfactory plan” approach is not a permissible interpretation of the statute, much less a reasonable one.

Further, the commenter (2399-GPA) asserts that the “satisfactory plan” interpretation does not consider the overall context and structure of Section 111. A “reasonable statutory interpretation must account for both ‘the specific context in which ... language is used’ and ‘the broader context of the statute as a whole.’”<sup>190</sup> The commenter contends that the “satisfactory plan” interpretation would make Congress’ clear decision to split the responsibility for establishing standards of performance between EPA (new sources) and the States (existing sources) completely illusory as, despite the text and structure, EPA would dictate standards of performance under both subsections.

And, finally, the commenter (2399-GPA) reports that the “satisfactory plan” interpretation is of a type that courts have strongly and repeatedly disfavored. “Congress, we have held, does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes.”<sup>191</sup> The commenter notes that courts are especially skeptical of such interpretations where, as here, an agency appeals to “vague terms or ancillary provisions” to overcome specific statutory delegations of authority.<sup>192</sup> The commenter states that here, the December 2022 supplemental proposed rule uses the vague and ancillary term “satisfactory plan” – residing in CAA section 111(d)(2)(A) – to wrench away the clear authority that Congress provided to states in CAA section 111(d)(1). The commenter asserts that nothing in the term “satisfactory plan,” or its surrounding context, indicates that Congress intended to modify CAA section 111(d)(1), much less provide EPA with the power to constrain the States’ “broad discretion” under that subsection.<sup>193</sup>

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<sup>189</sup> See, e.g., *Hibbs v. Winn*, 542 U.S. 88, 101 (2004) (a “statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant”) (internal quotations omitted).

<sup>190</sup> *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2442 (2014) (quoting *Robinson v. Shell Oil Co.*, 519 U.S. 337, 341 (1997)) (alterations in original); see also *Univ. of Texas Southwestern Med. Ctr. v. Nassar*, 570 U.S. 338, 353 (2013) (interpretations cannot be “inconsistent[t] with the design and structure of the statute as a whole”).

<sup>191</sup> *Whitman v. Amer. Trucking Assns., Inc.*, 531 U.S. 457, 468 (2001).

<sup>192</sup> Cf. *Banks v. Booth*, 3 F.4th 445, 449 (D.C. Cir. 2021) (“Appellees would have us hold that after having gone to this trouble with specificity to state exactly what it meant, Congress sub silentio created a further exception to its clear meaning ... we are not going to hold that Congress enumerated the mice and then unleashed an invisible elephant to trample the field.”).

<sup>193</sup> *Amer. Lung Ass’n*, 985 F.3d at 962.

*The Supplemental Proposed Rule’s “Standards of Performance” Interpretation is Unreasonable and Impermissible.* The Supplemental Proposed Rule separately argues that “there is a fundamental obligation under CAA section 111(d)” that existing source emission limits “reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA.” (emphasis added). This argument claims that, because Section 111(d) uses the term “standard of performance,” then Congress silently intended for EPA to establish existing source emission limits under CAA section 111(d)(1), not the States. For the same reasons as the “satisfactory plan” interpretation, the commenter contends that “standard of performance” interpretation is an impermissible and unreasonable one that lacks a statutory basis, contradicts CAA section 111(d)’s text and structure, and violates basic principles of statutory construction.

Response II-19-75: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

Comment: Commenter (2202-TXOGA) expresses disappointment that EPA failed to consider its concern regarding EPA’s misreading of *Union Electric* and what they believe is a misunderstanding of CAA section 116. The commenter urges EPA to reconsider its position and maintain an open mind on the proper interpretation of CAA section 116, as the terms that EPA employs in describing this important statutory savings clause indicate a serious error in EPA’s thinking regarding the scope and meaning of the provision. The commenter provides the following legal commentary to justify their position.

The commenter (2202-TXOGA) notes that, without discussing comments, EPA made but a single reference to the *Union Electric* decision in the December 2022 supplemental proposal notice. Moreover, in so doing, they contend that EPA did nothing more than repeat the fact that, in its November 2021 proposal, the Agency had “proposed that states are authorized to include in their state plans, and the EPA is authorized to approve, requirements that are more stringent than the EG under the authority of CAA section 116, as interpreted by the Court in *Union Electric v. EPA*, 27 U.S. 246, (1976).” And, EPA stated it was “now proposing” to go even further, that, “under CAA section 111(d), consistent with the authority conferred by CAA section 116, states may consider RULOF to include more stringent standards of performance in their state plans.”

The commenter (2202-TXOGA) asserts that CAA section 116 does not operate to grant “authority” to anyone, not to states and not to EPA. The commenter contends that is not what the provision is about, rather *it is a savings clause*. The commenter states that it preserves that state authority which might otherwise exist under state law. The commenter argues that it in no way creates authority, and it was necessary to distinguish those provisions where in fact, preemption was being created, such as under Title II. Indeed, the commenter asserts that CAA section 116 serves only to affirm that, except in certain specified instances, the CAA does not *preempt* states from exercising whatever authority they might otherwise possess, *as a matter of state law*, to establish their own emission standards and other requirements pertaining to sources within their jurisdiction.

Put simply, the commenter (2202-TXOGA) argues that CAA section 116 does not operate as an independent grant of authority to states to set their own more stringent emission standards, nor does it serve to authorize (much less require) EPA to approve, under CAA section 111(d), more stringent standards that a state may choose to adopt as a matter of state law. The commenter expresses concern that EPA now persists in characterizing CAA section 116 as constituting some sort of grant of “authority” – either to states to adopt more stringent standards of performance, or to the Agency itself to “approve” (and thereby make federally enforceable) any such emission standards under CAA section 111(d). The commenter contends that EPA misunderstands the meaning and effect of CAA section 116.

The commenter (2202-TXOGA) reports that nothing in the Supreme Court’s *Union Electric* decision lends credence to EPA’s position. In the ACE Rule, the commenter believes that the EPA had correctly recognized that the *Union Electric* decision “specifically evaluated whether the EPA has the authority to approve” a state implementation plan under CAA section 110 that is “more stringent than what is necessary to attain and maintain” the NAAQS.<sup>194</sup> In addressing itself to that question, the Court in *Union Electric* had “specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis,” a provision that is “wholly separate and distinct from CAA section 111(d).”<sup>195</sup>

The commenter (2202-TXOGA) notes that the December 2022 proposal says that EPA has changed its mind, that, upon further evaluation, it has come to believe, in light what it says it views as the “structural similarities” between CAA section 110 and CAA section 111(d), that CAA section 116 “as interpreted by *Union Electric*” requires the Agency to reverse itself. If EPA properly took account of the concerns that the commenter and others have raised, however, the commenter believes that the EPA would have put itself in the position to understand that, given the structural *dissimilarities* between CAA section 110 and CAA section 111(d), nothing in *Union Electric* provides support to the new proposed interpretation. The commenter urges EPA to focus further evaluation on the proper reading of *Union Electric*.

The commenter (2202-TXOGA) states that the issue that lay at the heart of *Union Electric* was whether the EPA Administrator was allowed to consider claims of “economic and technology infeasibility” in the course of the Administrator’s “approving or rejecting a state implementation plan” under CAA section 110. As first enacted in 1970 (and as it reads today), the commenter provides that CAA section 110 specified eight criteria that the Administrator was to assess in determining whether or not to approve a state’s implementation plan.<sup>196</sup> Where the Administrator determined that a plan met all those criteria, the Administrator was required to approve such plan.<sup>197</sup> Since, as the Court observed, a reviewing court, in addressing a petition for review, could only consider claims of “economic and technological infeasibility” if the Administrator himself was allowed to do so under CAA section 110, it was necessary for the Court first to “address ourselves to the scope of the Administrator’s responsibility.”<sup>198</sup> For the Administrator’s

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<sup>194</sup> 84 Fed. Reg. 32,560.

<sup>195</sup> Id.

<sup>196</sup> CAA section 110(a)(2)(A)-(H).

<sup>197</sup> CAA section 110(a)(2) (“The Administrator *shall approve* such plan . . . if he determines that it was adopted after reasonable notice and hearing and that” the plan satisfied the criteria specified in subparagraphs (A) through (H).) (emphasis added).

<sup>198</sup> 427 U.S. at 256.

part, the Court noted, his position “is that he has no power whatsoever to reject a state implementation plan on the ground that it is economically or technologically infeasible.”<sup>199</sup>

After undertaking its own examination of the “relevant provisions of the Clean Air Amendments of 1970” – i.e., the commenter (2202-TXOGA) states that the aforementioned CAA section 110(a)(2)(A)-(H) – as well as “their legislative history,” the Court found itself in agreement with EPA that “Congress intended claims of economic and technological infeasibility to be wholly foreign to the Administrator’s consideration of a state implementation plan.”<sup>200</sup> The CAA “place[s] the primary responsibility for formulating pollution control strategies on the [s]tates,” the Court observed, but at the same time the CAA subjected states to “strict minimum compliance requirements,” with those requirements being of a “technology-forcing character.”<sup>201</sup> In this respect, then, the Court said, those requirements “are expressly designed to force regulated sources to develop pollution control devices that might at the time appear to be economically or technologically infeasible.”<sup>202</sup> “This approach,” the Court continued, is “apparent on the face of § 110(a)(2).”<sup>203</sup> Insofar as CAA section 110(a)(2) “sets out eight criteria that an implementation plan must satisfy,” and provides that, “if these criteria are met,” the “Administrator ‘shall approve’ the proposed state plan,” the Court found it “quite clear” that the “mandatory ‘shall’” established that the Administrator “is not to be concerned with factors other than those specified.”<sup>204</sup> None of the eight factors listed under CAA section 110(a)(2), the Court opined, “appears to permit consideration of technological or economic infeasibility.”<sup>205</sup> “Nonetheless,” the Court said, “if a basis is to be found for allowing the Administrator to consider such claims, it must be among the eight criteria,” so it was there that the parties’ arguments were focused.<sup>206</sup>

First, the commenter (2202-TXOGA) reports it was “suggested that consideration of claims of technological and economic infeasibility is required by the first criterion” – i.e., that the “primary air quality standards be met ‘as expeditiously as practicable but . . . in no case later than three years . . .’ and that the secondary air quality standards be met within a ‘reasonable time.’”<sup>207</sup> The

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<sup>199</sup> Id. The Court then noted that it had “previously accorded great deference to the Administrator’s construction of the Clean Air Act.” Id., citing *Train v. NRDC*, 421 U.S. at 75.

<sup>200</sup> 427 U.S. at 256.

<sup>201</sup> Id. at 256-57, quoting *Train v. NRDC*, 421 U.S. at 91.

<sup>202</sup> Id. at 257.

<sup>203</sup> Id.

<sup>204</sup> Id.

<sup>205</sup> Id. at 257. At this point, the Court noted that a “[c]omparison of the eight criteria of § 110 (a) (2) with other provisions of the Amendments bolster this conclusion.” Id. at 257 n.5. “Where Congress intended the Administrator to be concerned about economic and technological infeasibility,” the Court continued, “it expressly so provided.” Id. For example, the Court said, CAA sections “110(e), 110(f), 111(a)(1), 202(a), 211(c)(2)(A), and 231(b) of the Amendments

all expressly permit consideration” of economic and technological infeasibility,” whereas Section 110(a)(2) contains no such language.” Id.(emphasis added). Thus, even though the issue was not specifically before the Court in *Union Electric*, the Court in passing had occasion to take notice of the structural differences existed between CAA Section 110 and CAA Section 111(a)(1), with the latter provision (as it read in 1970) defining “standard of performance” to mean a “standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.”

<sup>206</sup> Id. at 257.

<sup>207</sup> Id. at 257-58, quoting CAA section 110(a)(2)(A).

argument advanced was that “what is ‘practicable’ or ‘reasonable’ cannot be determined without assessing whether what is proposed is possible.”<sup>208</sup> This argument, the Court found, “does not survive analysis.”<sup>209</sup> As the Court reasoned, CAA section 111(a)(2)(A)’s “three-year deadline for achieving primary air quality standards, was “central to the Amendments’ regulatory scheme,” and, as “both the language and the legislative history of the requirement make clear, it leaves no room for claims of technological or economic infeasibility.”<sup>210</sup> After a careful review of the relevant legislative history, the Court determined that the “Conference Committee and, ultimately, the entire Congress” had come to accept the “Senate’s three-year mandate for the achievement of primary air quality standards.”<sup>211</sup> The “clear import of that decision,” the Court found, is that the “Administrator must approve a plan that provides for attainment of the primary standards in three years even if attainment does not appear feasible.”<sup>212</sup>

Having disposed of the principal argument of the petitioner, the commenter (2202-TXOGA) adds that the Court then took note of the argument of one of the amici. This amicus had claimed that the states “are precluded from submitting implementation plans more stringent than federal law demands” by the second criterion of CAA section 110(a)(2) – i.e., that the plan “contain such control devices ‘as may be necessary’ to achieve the primary and secondary air quality standards.”<sup>213</sup> The contention of the amici was that an “overly restrictive plan is not ‘necessary’ for attainment of the national standards and so must be rejected by the Administrator.”<sup>214</sup> As the Court explained it, the “principal support for this theory of amici lies in the fact that,” while the House and Senate versions of CAA section 110(a)(2) had “both expressly provided that the States could submit for the Administrator’s approval plans that were stricter than the national standards required,” the “section as enacted contains no such express language.”<sup>215</sup> According to the amicus brief, as the Court characterized its argument, the “Conference Committee must have decided to require state implementation plans simply – and precisely – to meet the national standards.”<sup>216</sup>

But the commenter (2202-TXOGA) states that the Court would not accept that. The “argument of amici,” the Court said “proves too much,” in that a Conference Committee “lacks power to make substantive changes on matters about which both Houses agree.”<sup>217</sup> Moreover, the Court pointed out, in this case the Conference Report had “expressly note[d] that both the Senate and House bills would allow [s]tates to submit plans more stringent than the national standards demand,” and the amici “offers no suggestion that the Conference bill intended to change that result, even if it could.”<sup>218</sup> “And while the final language” of CAA section 110(a)(2)(B) may have ended up being “less explicit than the versions originally approved by the House and the Senate,” the Court concluded, “the most natural reading of the ‘as may be necessary’ phrase in

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<sup>208</sup> Id. at 258.

<sup>209</sup> Id.

<sup>210</sup> Id.

<sup>211</sup> Id. at 259.

<sup>212</sup> Id.

<sup>213</sup> Id. at 262, quoting CAA section 110(a)(2)(B).

<sup>214</sup> Id. at 262.

<sup>215</sup> Id., citations omitted.

<sup>216</sup> Id.

<sup>217</sup> Id. at 262-63.

<sup>218</sup> Id. at 263.



context is simply that the Administrator must assure that the minimal, or ‘necessary,’ requirements are met,” not that he “detect and reject any state plan more demanding than federal law requires.”<sup>219</sup>

Having found the *amicus* argument to be without basis as a matter of law, the commenter (2202-TXOGA) reports that the Court then added that its reading of the statutory language and legislative history was “further supported by *practical considerations*.”<sup>220</sup> The Court took note that “Section 116 of the Clean Air Act . . . provides that the States may adopt emission standards stricter than the national standards.”<sup>221</sup> The amici had argued that “such standards must be adopted and enforced independently of the EPA-approved state implementation plan.” In response, the Court observed that “this construction of §§ 110 and 116 . . . would not only require the Administrator to expend considerable time and energy determining whether a state plan was precisely tailored to meet the federal standards,” but, as well, would “simultaneously require [s]tates desiring stricter standards to enact and enforce two sets of emission standards, one federally approved plan and one stricter state plan.”<sup>222</sup> Finding “no basis in the Amendments for visiting such wasteful burdens upon the States and the Administrator,” the Court rejected the *amicus*’s argument.<sup>223</sup>

As the foregoing review of *Union Electric* shows, according to the commenter (2202-TXOGA), what EPA now appears to think the Court said and held in *Union Electric* is not what the Court said and held at all. The commenter states that the EPA’s contention that “[r]equiring [s]tates to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter [s]tate plan” would run “directly afoul of the court’s *holding* that there is no basis for interpreting CAA section 116 in such manner”<sup>224</sup> is misplaced. The commenter contends that the Court in *Union Electric* offered no such “holding” with respect to CAA section 116.<sup>225</sup> To the extent the Court set forth any “interpretation” of CAA section 116 at all, it offered nothing more than the observation that, in light of the “practical considerations” involved, it could find “no basis in the Amendments” – i.e., in the interaction of CAA section 110(a)(2)(B) and CAA section 116 – for accepting *amici*’s claim that a state should be required in such circumstances to “enact and enforce two sets of emission standards.” Insofar as the

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<sup>219</sup> Id.

<sup>220</sup> Id. (emphasis added).

<sup>221</sup> Id. at 263-64.

<sup>222</sup> Id. at 264. The Court here noted that the “burden” on the Administrator to determine whether a state plan was “precisely tailored to meet the federal standards” would be “particularly onerous in view of the facts that Congress gave the Administrator only four months in which to evaluate each plan submitted . . . and that all state plans are submitted at approximately the same time.” Id. at 264 n.11.

<sup>223</sup> Id. at 264 (emphasis added).

<sup>224</sup> See 87 Fed. Reg. at 63,252.

<sup>225</sup> The actual holding of *Union Electric* is to be found in its conclusion that “claims of economic or technological infeasibility may not be considered by the Administrator in evaluating a state requirement that primary ambient air quality standards be met in the mandatory three years.” 427 U.S. at 265. The Court further concluded that, as states “may submit implementation plans more stringent than federal law requires and that the Administrator must approve such plans if they meet the minimum requirements of § 110(a)(2),” it follows that the language of CAA section 110(a)(2)(B) “provides no basis for the Administrator ever to reject a state implementation plan on the ground that it is economically or technologically infeasible.” Id. In light of this, according to the commenter, the question at hand is not so much whether the Court’s discussion of CAA section 116 constitutes any part of its “holding” but whether, in context, that discussion can even be said to rise above the level of dicta.

circumstances involved in *Union Electric* are altogether distinct from those presented by EPA's approval of state plans under CAA section 111(d), the Agency's assertion that it would somehow "run afoul" of *Union Electric*'s "holding" unless it were to approve (and thereby render federally enforceable) state standards that are more stringent than the presumptive standards based on EPA's determination of BSER, cannot be credited. *Union Electric* demands no such outcome. The commenter asserts that the decision speaks not at all to any such outcome.

Similarly, the commenter (2202-TXOGA) argues that nowhere did the Court "interpret[] CAA 116" in a manner that establishes that EPA is "*require[d]* to approve CAA section 111(d) [s]tate plans that are more stringent than required by the EG," where such plans are "otherwise i[n] compliance with all applicable requirements."<sup>226</sup> EPA contends that the Court in *Union Electric* had "rejected a construction of CAA sections 110 and 116 that measures more stringent than those required to attain the NAAQS" could not "be approved into federally into a federally enforceable . . . (SIP) but must be adopted and enforced only as a matter of [s]tate law."<sup>227</sup> Even so, in rejecting such a "construction of CAA section 110 and 116," the Court had no occasion to speak to the separate question of whether EPA is authorized to approve (much less that EPA is required to approve) under CAA section 111(d) standards or requirements adopted under state law that are more stringent than EPA's presumptive standards. The commenter and others have already explained why the fundamental differences between CAA section 110 (the provisions of which were at issue in *Union Electric*) and CAA section 111(d) (the provisions of which were not at issue), dictate that the Supreme Court's decision does not control here. And, of course, not that long ago the commenter notes that the EPA thought the same itself.<sup>228</sup>

But, the commenter (2202-TXOGA) states, the preamble adheres to the position, arguing that, "[w]hile the BSER and the NAAQS are distinct from one another in that the former is technology-based and the latter is based on ambient air quality," both CAA section 111(d) and CAA section 110 are "structurally similar in that [s]tates must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section."<sup>229</sup> But that is as far as the "similarities" go, and the commenter contends that is not nearly far enough to make such a case. To the contrary, the commenter contends that the dissimilarities between the two provisions are manifest.

The commenter (2202-TXOGA) provides that the plan called for under CAA section 111(d)(1) is "a plan which . . . establishes standards of performance for any [covered] existing source . . ." A standard of performance reflects the degree of emission limitation achievable through application of BSER "which (taking into account [cost, non-air quality effects and energy requirements]) [is] . . . adequately demonstrated." Accordingly, as has previously been noted, a "standard of performance" that set forth a degree of emission limitation which was *more stringent* than that which would be achievable through the application of BSER would not be a "standard of performance" at all – not one that is consistent with the definition set forth in CAA [s]ection 111(a)(1), that is. When *Union Electric* was decided, the commenter states that plans under CAA

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<sup>226</sup> See 86 Fed. Reg. at 63,251-52.

<sup>227</sup> Id. at 63,252.

<sup>228</sup> See 84 Fed. Reg. at 32,560 ("EPA believes that *Union Electric* does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.")

<sup>229</sup> Id.

section 110 required “emission limitations . . . as may be necessary to assure attainment and maintenance” of the ambient standards and were to be tailored by states based on the types of emissions and emission sources in the attainment/non-attainment area at issue. While BSER defines a “degree of emission limitation” which establishes both a floor and a ceiling for a standard of performance, ambient standards set only a floor. According to the commenter, under CAA section 110, there is no ceiling restricting the stringency of an emission limitation that “attains” an ambient standard, or a limitation that “maintains” air quality at a level below the ambient standard.

The commenter (2202-TXOGA) argues that this fundamental difference between plans that states are directed to submit under CAA section 110(a)(2) and those that states are called on to submit under CAA section 111(d) is stark and serves to distinguish EPA’s review of state plans under CAA section 111(d) from the situation which concerned the Court in *Union Electric*, where (under the *amicus*’s view of things) EPA would have been required to “expend considerable time and energy determining whether a state plan was precisely tailored to meet the federal standards.”<sup>230</sup> The commenter notes that this “practical consideration” is not in play with respect to the Agency’s review of state plans under CAA section 111(d). They state that any standard of performance or other requirements that might be adopted by a state, under state law, which were more stringent than the presumptive standards of performance derived from EPA’s determination of BSER would be readily identifiable.<sup>231</sup>

As for the Court’s additional observation that, under the *amici*’s view of CAA section 110(a)(2), the commenter (2202-TXOGA) provides that it states “desiring stricter standards” would be required to “enact and enforce two sets of emission standards, one federally approved and one stricter state plan,” such an outcome would impose no “wasteful burden” on states in the context of CAA section 111(d).<sup>232</sup> For those states that might choose to adopt, as a matter of state law, more stringent requirements for existing sources, the commenter adds that CAA section 111(d) requires that those separate more stringent state standards be precluded from the state’s CAA section 111(d) plan. In contrast to the situation in *Union Electric*, where EPA’s approval of a state’s implementation plan that included more stringent requirements than might be “necessary” to “insure attainment and maintenance of [the] primary and secondary standards” did not run afoul of CAA section 110(a)(2), were the Agency to approve, under CAA section 111(d), requirements more stringent than would be warranted under EPA’s BSER determination, that would most assuredly violate the CAA. CAA section 111(d) provides that the “regulations” that EPA is to “prescribe” are to “establish a procedure . . . under which each State shall submit to the Administrator a plan which . . . establishes standards of performance” for existing sources. The commenter asserts that CAA section 111(d) says nothing of EPA’s being authorized to approve, and thereby render federally enforceable, state-law based requirements that, being more stringent than EPA’s BSER determination, cannot constitute “standards of performance.” The commenter

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<sup>230</sup> 427 U.S. at 264.

<sup>231</sup> Further, the commenter states that unlike in the case of CAA section 110 (as it read upon enactment in 1970), which the Court in *Union Electric* observed subjected the Administrator to a schedule where he was afforded, statutorily, “only four months in which to evaluate each plan submitted,” which would make “particularly onerous” any requirement by which the Administrator had to determine whether a state plan was “precisely tailored to meet the federal standards,” EPA can under CAA section 111(d) set for itself, through legislative rulemaking, the schedule by which it will review state plans, to see if they are “satisfactory.”

<sup>232</sup> 427 U.S. at 264.

believes that it follows therefore, on the face of CAA section 111(d), that EPA does not have such authority, for it would authorize EPA to approve states to enforce as federal law a standard that EPA itself could not have issued.<sup>233</sup> The commenter concludes that nothing in what the Court held in *Union Electric* says otherwise.

Response II-19-76: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

### ***19.8.3 EPA State Plan Approval of More Stringent Alternative Standards Based on RULOF is Consistent with EPA's Authority***

Comment: Commenter (2410-CA AG et al) supports EPA's interpretation in the December 2022 supplemental proposal that the statute authorizes EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by the EG.

The commenter (2410-CA AG et al) states that in the December 2022 supplemental proposal, EPA proposes that under CAA section 111(d), consistent with authority reserved to states pursuant to section 116 of the CAA, states may consider other factors to include more stringent standards of performance in their state plans. In reconsidering its previous interpretation in the ACE rule, EPA proposes to interpret that the statute authorizes EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by the emissions guideline.<sup>234</sup>

The commenter (2410-CA AG et al) agrees with EPA's explanation that there is nothing in the language of CAA section 111(d) suggesting that EPA has the authority to preclude states from determining that it is appropriate to regulate certain sources within their jurisdiction more strictly than otherwise required by federal requirements. And the commenter agrees that the inclusion of the "other factors" language in CAA section 111(d) demonstrates that Congress envisioned that states could consider additional circumstances—such as effects on local communities—in determining standards of performance for specific facilities.

Response II-19-77: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

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<sup>233</sup> According to the commenter, this stands in contrast to a situation in which a state adopts requirements that provide assurance it will meet the NAAQS, with some level of comfort. We note that EPA has never taken the position that a state's adoption of a more stringent ambient air quality standard, such as those state Ambient Air Quality Standards (AAQS) adopted by California, are themselves subject to SIP requirements.

<sup>234</sup> EPA has proposed a similar interpretation in the context of its proposed section 111(d) implementing regulations.

## **19.9 Section 111(d) Implementing Regulations**

Comment: Commenters (2222-WDNR, 2446-IPAA) note that, in a separate action, EPA proposed updates to the general implementation provisions for state plan development under CAA section 111(d).

Commenter (2222-WDNR) notes that EPA identified several areas in the methane proposal where the general implementing regulations would apply to state plan development. Therefore, the commenter recommends that EPA consider all applicable comments received in the general implementation regulation docket (EPA-HQ- OAR-2021-0527) when finalizing the methane NSPS and EG for oil and natural gas sources.

Similarly, commenter (2446-IPAA) recommends that EPA assess the two proposals together because EPA has indicated that for those issues not directly addressed in the EG OOOOc proposal, the provisions of the general regulations would apply. However, the commenter recognizes that this creates a problem because the two different proposals have different completion schedules.

The commenter (2446-IPAA) suggests that the intent of Congress in crafting CAA section 111(d) was to create a program to fill the potential gaps regulating existing sources of emissions when new source regulations were created for pollutants that were neither criteria pollutants nor hazardous air pollutants, both of which have existing source provisions. Because CAA section 111(d) was written long before EPA decided to regulate GHG, the commenter believes that it did not envision a circumstance where there would be a million existing sources to address. The commenter believes that this difference is substantial regarding the structure of state programs and the structure of EPA's CAA section 111(d) requirements. The commenter adds that they believe that some of these issues are inherent in the challenges of regulating so many sources; whereas others result from EPA putting its thumb on the balance to limit state options.

Response II-19-78: Please see the final Implementing Regulations rulemaking, 88 FR 80480, and the Summary of Public Comments and Responses on Proposed Rule Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d) (Subpart Ba) Docket ID No. EPA-HQ-OAR-2021-052.

## **19.10 Implementation Authority – EPA Coordination with State, Tribal and Local Government Regulatory Authorities**

Comment: Commenter (2403-PAO) requests that EPA coordinate with states and incorporate ways to reduce process requirements to allow states the flexibility (as allowed by the CAA) to develop and implement state specific requirements for existing emission sources.

The commenter (2403-PAO) asserts that by dividing regulatory authority under Clean Air Act section 111 into separate programs for new and existing sources, Congress clearly recognized that existing sources are less able to comply with new regulatory requirements than new sources. The commenter notes that if states do not adhere to the presumptive standards for existing sources, state delegated agencies would be required to conduct lengthy analysis and write major

regulations or face imposition of a federal plan. The commenter contends that EPA is basically forcing states to “accept” the proposed standards.

Commenter (2219-WOGCC) expresses concern with EPA proposing regulations outside of its authority and the burden placed on operators. The commenter recommends that EPA remove the proposed requirements and propose regulations only on issues that it is granted authority over.

The commenter (2219-WOGCC) reports that the Wyoming Oil and Gas Conservation Commission is the state regulatory agency for the oil and gas industry in Wyoming. The commenter notes that they regulate all aspects of wells in the state including rules on venting and flaring, well drilling and completions, well operations, and well plugging, while the Wyoming Department of Environmental Quality (WDEQ) regulates air quality at oil and gas locations. In addition to WOGCC and WDEQ regulations, wells on federal lands must also comply with Bureau of Land Management (BLM) regulations, inserting layers of regulations and regulatory agencies that operators must consider.

The commenter (2219-WOGCC) contends that the proposed rule creates yet another regulatory burden that will be placed on wells and operators in Wyoming. When evaluated in conjunction with the recently announced BLM rule on waste prevention the commenter asserts that these rules become sometimes duplicative, sometimes conflicting, but always burdensome on operators to navigate how to remain in compliance with each. According to the commenter, not only does EPA's proposed rule place these burdens on an operator related to air quality regulations, but they believe that EPA is proposing regulations outside of its authority on issues such as well plugging and financial assurance. The commenter asserts that these issues are clearly within the state's and BLM's regulatory authority, not EPA.

Commenter (2292-WV AG et al) expresses concern that the proposal departs from CAA's statutory text and cooperative federalism. The commenter notes that the commenter previously commented (in their comments on the November 2021 proposal) that the EPA's proposed rule departed from the CAA's statutory text and cooperative federalism regime. The commenter contends that the December 2022 supplemental proposal ignores those concerns—and indeed worsens them. The commenter identified two problematic aspects of the December 2022 supplemental proposal. First, EPA suggests tightening the proposed requirements under CAA section 111(b) for methane and VOC emissions from sources that began construction, modification, or reconstruction after November 15, 2021. The commenter notes that these requirements include proposed standards for emission sources that have never been regulated in this way before. Second, EPA proposes to impose the first nationwide EG for states to reduce methane emissions from existing facilities.

The commenter (2292-WV AG et al) asserts that EPA proposes to flout the CAA's text by trying to regulate sources that cannot be (and have not been) regulated and attempts to recast existing sources as new sources. The commenter asserts that EPA action ignores the collaborative role the states play in methane regulation, ignoring Congress and the states' essential role. The commenter argues that the December 2022 supplemental proposal threatens to relegate the states to mere side players by limiting their legislatively endowed discretion in unreasonable and arbitrary ways.

Response II-19-79: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble; discussion of the applicability date in section IX of the final preamble; and section IV.A and V regarding the EPA's authority and legal basis for this action.

## **19.11 Develop Existing Source Standards Under a Separate Rulemaking**

Comment: Commenter (2283-Endeavor Energy) recommends that EPA conduct existing source standards separate from new source standards, otherwise they believe that EPA risks finalizing EGs that are arbitrary, capricious, overly burdensome, and unworkable in practice, which would undermine EPA's goal of creating durable methane regulations. As EPA has noted in the past, the commenter provides that EPA is "proposing (or publishing) an emission guideline after promulgation of the corresponding standard of performance" allows EPA to "benefit from the comments on the standard of performance in developing the emission guideline."<sup>235</sup> The commenter asserts that is equally true here: When EPA proposed NSPS OOOOa, the commenter states that it did not simultaneously propose EGs for methane at that time. The commenter agrees that this was appropriate, as it would allow for EPA to first benefit from the experience and information gained from observing ways in which NSPS OOOOa was, and was not, effective before applying any standards to the much larger universe of existing sources. The commenter notes that NSPS OOOOa has not been in place for very long, due to the legal challenges/changes. As a result, the commenter suggests that the EPA does not yet have sufficient information about the effects or effectiveness of the various requirements it has imposed to limit methane emissions and therefore lacks sufficient information to determine what requirements would be appropriate and effective for existing sources. In addition, the commenter adds that the EPA has not yet received and reviewed comments on its new proposed NSPS OOOOb, which introduces several additional requirements beyond NSPS OOOOa that have not yet been tested in the field and which are likely to present meaningful implementation challenges. In consideration of these meaningful information gaps, the commenter recommends that EPA withdraw the proposed EG OOOOc and wait to propose what they believe would be a more appropriate set of regulatory requirements for existing sources with the benefit of additional information and experience.

The commenter (2283-Endeavor Energy) states that eventual existing source EGs must be less stringent than the NSPS requirements in recognition of the very different set of burdens and considerations at play when regulating existing sources. Specifically, the commenter believes that the proposed EGs should appropriately accommodate other factors, such as the remaining useful life of existing sources, as required by the CAA.<sup>236</sup> The commenter recommends that EPA's reflect the CAA's recognition that there are a fundamentally different set of considerations when regulating existing sources for the first time. Like many operators, the commenter states that they have already planned and budgeted for equipment upgrades at new or modified well sites, but upgrades at the older, existing sites will be more costly to make and will need to be made at far more sites than for new or modified sites. Depending on the specific well site, the commenter provides that these capital upgrade costs could fundamentally alter economics associated with operating an existing well or be entirely infeasible to implement. For example, the commenter explains that many existing well sites contain a limited number of

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<sup>235</sup> See, e.g., 40 Fed. Reg. 53,340, 53,345 (Nov. 17, 1975).

<sup>236</sup> 42 U.S.C. §741 l(d)(l).

controllers, most do not have flares located on site, and the complete retrofit of these sites is likely cost-prohibitive based on well economics. The commenter states that the EPA's proposal will require installing and retrofitting a broad range of equipment, including installing electric compressors for air controls, retrofitting all controllers to air systems, installing vapor recovery units on all tanks, installing new low- and high-pressure flares, and installing meters to monitor the volumes sent to flares. In addition, the commenter reports that many older well sites do not have access to on-site electricity or a sale line for natural gas because the sites were not built with these considerations in mind. And due to the remote locations of many of these existing sites in the Midland Basin, these kinds of infrastructure upgrades will be extremely costly or entirely outside of an operator's control.

The commenter (2283-Endeavor Energy) asserts that because many older sites do not produce as much oil or gas, the new compliance obligations could very well alter the "remaining useful life" of the well and cause wells to be shut in or prematurely abandoned. The commenter reports that this is true for many producers and could have far-reaching impacts on domestic oil and gas production. The commenter states that CAA section 111(d)(1) explicitly directs EPA to ensure that its EGs permit the states to take remaining useful life and other factors in account. However, the commenter contends that the overly prescriptive and inflexible approach proposed by EPA does not properly reflect this statutory requirement. The commenter recommends that in addition to revising the actual EGs, EPA must revise its economic analysis to reflect the fact that the economics of EPA's proposed EGs are fundamentally different and more burdensome to the industry than the NSPS.

The commenter (2283-Endeavor Energy) expresses concern that there are insufficient number of contractors who can meet the needs of all operators in the Midland Basin, and "scaling up" too quickly would pose risks if contractors are forced to rely on new personnel who do not have qualifications, training, and experience to perform the necessary upgrades. The commenter notes that this is just one example of why EPA cannot and should not assume that just because requirements have proven to be feasible for the much smaller pool of new or modified sources that operators are also able to implement these requirements more broadly for their existing sources.

The commenter (2283-Endeavor Energy) therefore recommends that EPA take the time to fundamentally revisit its proposed EGs after coordinating with the states, who have decades of experience regulating these sites, and operators, who likewise understand the practical realities of implementing these proposals. The commenter encourages EPA staff to visit a variety of well sites in our basin and others to better understand the nature of these facilities and the geography where we are operating. By spending the necessary time up front to understand the industry, the commenter believes that the EPA can craft durable and workable requirements that will better serve the environment and the public in the long run and avoid issuing a rule that cannot survive legal challenges.

Response II-19-80: Please see discussion of standards of performance and state flexibilities, and response to comments, section XIII.C of the final preamble.



## Chapter 20. Impacts of the Proposed Rule

### 20.1 Regulatory Analysis

#### *20.1.1 Costs and Benefits of Proposed Rule*

##### 20.1.1.1 Costs and Benefits Analyses

Comment: Commenters (2219-WOGCC, 2257-MOGA, 2399-GPA) believe that the cost benefit analysis is insufficient as proposed. Comments received are provided in the following paragraphs.

Commenter (2257-MOGA) asserts that EPA must address the potential costs and problems associated with a breach of contract before expanding regulations to existing sources. Further, the commenter asserts that EPA must include these costs and ramifications in their cost per ton of methane reduction to adequately represent the true costs of imposing future regulations on industry.

The commenter (2257-MOGA) asserts that EPA did not solicit comments from the oil and gas production industry and small businesses or attempt to understand the potential impacts of the proposed regulations on existing contracts. The commenter reports that before a well is drilled or a facility is constructed, surface and underground asset contracts are prepared and presented to the landowners for review, discussion, modifications and final authorization. These contracts allow the potential producing company to enter the property for review, acknowledgment of the complication in the terrain and apply for additional permits and contracts, negotiate with the landowner for mineral rights, access fees and mineral distributions. Additional contracts with utilities, transportation companies, pipeline operators and regulators are prepared, reviewed and signed before a well is drilled and determined to be commercial and viable. The commenter asserts that all the above-mentioned contractual obligations become null and void if the well is not economically sustainable.

Commenter (2399-GPA) urges EPA to improve their cost and benefits analysis before making any determination on whether certain regulatory requirements are cost effective for the midstream industry. The commenter contends that EPA's analysis includes significant oversights with respect to the midstream industry. The commenter notes that owners and operators of gathering and boosting compressor stations do not own the gas that they process and, therefore, recoup no financial benefits from reducing lost gas as EPA assumed. Further, the commenter states that several necessary costs were omitted, such as compressor monitoring costs, installation costs, and the need for vapor recovery units. The commenter recommends that EPA examine cost-effectiveness on a single pollutant basis and correct its cost-effectiveness analysis. Their comments follow:

- EPA Should Examine Cost-Effectiveness on a Single Pollutant Basis. In reviewing whether control costs for the midstream sector are reasonable, EPA should look at the full cost of control as applied to each pollutant – VOCs [volatile organic compounds] and methane. Each pollutant should be evaluated separately as to whether the system would

or would not be cost-effective in determining whether to require the control. Here, based on our review to date, when the proper set of costs are considered, it is plain that controls for centrifugal compressors at gas plants are not cost-effective.

EPA has long looked at whether the cost of a particular system of control is reasonable by considering the costs associated with such control, including capital costs and operating costs, determining the emission reductions that the control can achieve, and then evaluating whether a particular control achieves that emission reduction cost effectively. In this context, EPA has calculated a control's "cost-effectiveness" by taking the annualized cost of implementing an air pollution control option divided by reductions realized annually for that pollutant.

In this rulemaking, EPA has looked at cost-effectiveness using a single pollutant approach but has also considered a "multi-pollutant" evaluation that divided control costs between VOCs and methane and then evaluated the cost-effectiveness of the control based on that reduced cost. 86 Fed. Reg. 63155 (Nov. 15, 2021). We urge EPA not to apply the so-called multi-pollutant approach in this case. Rather, in evaluating whether a particular "standard of performance" is appropriate here, EPA should look at each pollutant separately. This hews most closely to the direction of Congress. Section 111 requires EPA to consider a standard that reflects the degree of emission reduction achievable through the best system of emission reduction "taking into account the cost of achieving such reduction" as well as other factors. 42 U.S.C. § 7411(a)(1). In this case, the cost of achieving "such reduction" of methane is the full cost of control, not an apportioned cost or shared cost. The fact that there may be other benefits from installing the controls does not change the statutory requirement.

Not only is this approach consistent with statutory language, it is the right policy choice here. The fundamental purpose behind EPA's regulation is reducing methane emissions, and thus it is the cost-effectiveness of the system of reduction for that pollutant that should be evaluated. E.g., 87 Fed. Reg. 63113 (Purpose of the Regulatory Action). But for the presence of methane emissions, it seems highly improbable that EPA would be embarking on this expansive effort to develop new regulations. Nor does this result in double counting of the cost of controls as others have suggested – it merely evaluates each pollutant on its own merits to assess whether "such reduction" meets the cost criteria in the statute.

- EPA Should Correct its Cost-Effectiveness Analysis for Midstream, Because Gathering and Boosting Compressors See No Financial Benefits. In several locations throughout the Supplemental Proposed Rule, Regulatory Impact Analysis [RIA], and TSD [Technical Support Document], EPA asserts that gathering and boosting facilities own the natural gas in their systems and would directly benefit from capturing gas that would otherwise be lost. This is incorrect. Gathering and boosting facilities, and other midstream facilities, are typically paid a fee to prepare it for delivery to an interstate pipeline system. This is true even in large integrated companies that own both the production facilities and midstream facilities (e.g., gathering and boosting compressors, processing plants). The production segment and the midstream segment are separate business units, and the

production segment still pays a fee to the midstream segment for processing. This makes the midstream segment much more like transmission and storage segment facilities instead of production facilities.

Because the Clean Air Act [CAA] requires EPA to take “into account the cost of achieving” emission reductions, 42 U.S.C. § 7411(a)(1), EPA should revise and update its cost estimates to reflect the lack of financial benefits to the midstream sector. Given EPA’s focus on the alleged benefits from enhanced recovery of methane, it is critical for EPA to correct its analysis and revise its cost effectiveness determination as applied specifically to the midstream sector. The commenter previously raised this issue, and urges EPA to correct the record and redo its analysis for this proposed regulation. The commenter provides further details in the submission attachment Exhibit A 6-7.

Commenter (2219-WOGCC) suggests that the EPA did not conduct an accurate or complete evaluation of the costs and benefits of the proposed rule. The commenter notes that EPA does not fully compare the cost of compliance against the actual benefits resulting from the proposed rule. Instead, EPA compares cost of compliance against the total capital expenditures of the entire oil and gas industry sector and cost of compliance against sector level revenues. The commenter adds that the EPA then cherry-picks the years that it uses for the comparison of capital expenditures and revenues. EPA mentions that although capital expenditures from 2020 were available, since that year was affected by coronavirus disease (COVID-19) they would not use it, instead utilizing data from 2019. EPA reaches back even further when looking at revenues and utilizes industry revenues from 2017 when comparing costs and sector wide revenue. Unfortunately, the commenter states that industry will not be able to use the same argument when spending capital to comply with this rule.

The commenter (2219-WOGCC) explains that industry must deal with commodity price fluctuations and evaluate how to allocate capital, but if oil and gas prices drop in the future due to another COVID-19-like situation or any other issue that causes price fluctuations, it must still comply with this costly and burdensome rule. By cherry-picking the best years for capital expenditures and revenues, the commenter suggests that EPA attempts to obscure the actual costs of this rule on industry.

According to the commenter (2219-WOGCC), if EPA completed an appropriate cost and benefit analysis, it would tell a significantly different story. But the commenter states that EPA did provide some information that hints at the true costs and benefits. EPA estimates that the equivalent annual value (EAV) of the increase in compliance costs is \$1.7 billion (per year) without considering revenue from product recovery and \$1.2 billion (per year) when factoring in the revenue from product recovery. Thus, it will cost industry at least \$1.2 billion per year from 2023 through 2035 (and beyond) to comply with just the New Source Performance Standards (NSPS) and Emissions Guidelines (EG) of this proposed rule. So, the commenter provides that when conducting just a very generalized evaluation of the costs and benefits, this rule places very high costs of compliance on the industry and returns very little in benefits.

Although this review does indicate truer costs to the industry, the commenter (2219-WOGCC) suggests that it still is not entirely accurate. The commenter contends that the EPA decided to

obscure the true cost of compliance on industry by combining costs of compliance of the entire rule and comparing those across industry as a whole. The commenter states that a more accurate analysis would be to split the higher producing unconventional wells from low producing oil and gas wells sometimes known as stripper wells. The commenter notes that the cost to comply for these low producing stripper wells will be significant, which do not return the same revenue to industry as the higher producing conventional wells. By considering all of these types of wells together, the commenter suggests that the EPA has buried the severe impact on low producing wells in the revenues generated by the higher producing unconventional wells.

Response II-20-1: For a complete discussion of EPA's analysis conducted in accordance with E.O. 12866, in which it projected the emissions reductions, costs, and benefits that may result from this final rulemaking, see the Final Rule preamble at Section II.C, as well as the accompanying RIA.

To the extent that commenter (2257-MOGA) asserts that EPA should have considered the potential impacts of the NSPS OOOOb and EG OOOOc on existing contracts, it is unclear to the EPA exactly how the commenter suggests it should have done so. Commenter neither provides any specific data or analysis to support its argument, nor explains how any such analysis might have affected the EPA's establishment of standards of performance. It is unclear to the EPA how any analysis of contracts would have influenced the final rule.

EPA disagrees with the commenter's (2219-WOGCC) assertion that it cherry-picked analysis years for the comparison of estimated costs to sector-level capital costs and revenues. EPA maintains that 2019 was a sensible choice for an analysis of capital costs due to the COVID-19 pandemic, but the analysis for the Final Rule presents results for four years, 2018–2021, including two pre-pandemic and two post-pandemic years (see Chapter 5 of the Final Rule TSD), without changing the overarching conclusions. In addition, as explained in the December 2022 Proposal, the revenue data is from 2017 because that is the most recent year available.

EPA disagrees with commenter's (WOGCC) assertion that the rule would have a severe impact on low-producing wells. The commenter does not provide data to substantiate this claim nor define severe impacts. EPA also developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. Regarding the cost-effectiveness analysis for midstream, EPA calculated the annual costs and cost effectiveness values considering savings for gathering and boosting facilities. While EPA recognizes that in many cases, midstream facilities do not own the natural gas and would not recognize these savings, this is not universally true. However, it should be noted that all the final BSERs options selected for the final rule were determined to be cost effective without consideration of those natural gas savings. In other words, BSER determinations were not impacted by assumptions regarding natural gas savings.

In response to the comment that requests that EPA examine cost-effectiveness on a single pollutant basis when evaluating controls for reducing VOC and methane emissions from new

sources, we consider a control's cost effectiveness under both a "single-pollutant cost effectiveness" approach and a "multipollutant cost effectiveness" approach in order to appropriately take into account that the systems of emission reduction considered in this rule typically achieve emission reductions of multiple pollutants simultaneously and therefore result in a multiplicity of climate and public health benefits. For a detailed discussion of these cost approaches, please see section VIII.B (How does the EPA evaluate control costs in this final action?) of the final rule preamble as well as section IX.B (How does EPA evaluate control costs in this action?) of the November 2021 Proposal preamble<sup>1</sup> and section III.E (How does the EPA consider costs in this supplemental proposal?) of the December 2022 Supplemental Proposal preamble.<sup>2</sup> We believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. The EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option. See e.g., 80 FR 56616–6617; 73 FR 64079–64083 and EPA Document ID Nos. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

In response to comment that the EPA should correct its cost-effectiveness analysis for midstream, because gathering and boosting compressors see no financial benefits, the EPA acknowledges the commenter's input. While EPA recognizes that in many cases, midstream facilities do not own the natural gas and would not recognize these savings, this is not universally true. However, it should be noted that all the final BSERs options selected for the final rule were determined to be cost effective without consideration of those natural gas savings. In other words, BSER determinations were not impacted by assumptions regarding natural gas savings.

In addition, Section 2.4 of the RIA text notes that operators in the gathering and boosting, processing, and transmission and storage segments of the industry do not typically own the natural gas they transport. From a social perspective, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in a national-level analysis, as they represent benefits to society regardless of whether producers, consumers, or both realize those benefits. In the long run, no single entity bears the entire burden of compliance costs or fully appropriates the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is likely to be spread across different market participants. The compliance costs and revenues are kept within a given source category and the costs and revenues are not allocated across agents.

Comment: Commenter (2241-UDNR) notes that while it may be true that the EPA's new rule will "increase recovery of natural gas that otherwise would go to waste, valued at \$690 million in 2030 alone,"<sup>3</sup> the Proposed Rule does not seem to contemplate that the rule will instead leave

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<sup>1</sup> 86 FR 63154-63157.

<sup>2</sup> 87 FR 74718-74719.

<sup>3</sup> U.S. EPA, EPA Training on 2021 Proposal to Reduce Air Pollution from the Oil and Natural Gas Industry: Day 1, United States Environmental Protection Agency, available at: <https://www.youtube.com/watch?v=7VWAEcF65qU> (2021); see also <https://www.epa.gov/system/files/documents/2021-11/epas-proposed-oil-and-gas-rules.presentation-11.2.2021.pdf>.

tons of natural gas stranded and unproduced. Due to the added costs associated with compliance (again imposed on the oil and gas operators), the commenter argues that many oil and gas sources would become uneconomical to extract. While the State/commenter is supportive of finding innovative ways to reduce air pollution and methane emissions, the assert that it must be done in a way that equitably allocates costs and benefits, and without jeopardizing the resilience of the State's oil and gas industry.

Response II-20-2: The EPA disagrees with commenter's (UDNR) assertion that the rule would leave tons of natural gas stranded. The commenter does not provide data to substantiate this claim. EPA's analysis, presented in Section 4.1 of the RIA, estimates that the reduction in U.S. natural gas production as a result of the Final Rule would be approximately 0.75% or less. In addition, EPA also developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and therefore the impact of lost revenue would be minimal.

Comment: In support of the proposed rule, commenter (2425-TCS) weighs in that, in addition to taxpayer-funded incentives under the Inflation Reduction Act (IRA), the projected costs for industry represent a small fraction of their overall capital expenditures. The commenter states that the equivalent annual value (EAV) of net compliance costs of the Supplemental Proposal is \$1.4 billion (\$2019). According to Mercer Capital,<sup>4</sup> 28 selected exploration and production (E&P) companies, both global and independent, operating in Bakken, Appalachia, Permian, and Eagle Ford, reported \$138 billion in capital expenditures in 2019 and were expected to spend \$109 billion in 2022. Therefore, the commenter notes that the annual compliance cost is roughly 1.3% of 2022 capital expenditures of the selected companies and likely a lower percentage of total annual capital expenditures of the entire U.S. upstream oil and gas sector. The commenter adds that E&P spending is also expected to increase both internationally and in North America by at least 14% in 2023, according to the 2023 Evercore ISI E&P Spending Outlook.<sup>5</sup> U.S.-based supermajors like ExxonMobil and Chevron have both announced increased 2023 capital budget.<sup>6</sup>

Response II-20-3: EPA acknowledges the supportive comment.

#### 20.1.1.2 Benefits Overestimated/Underestimated

Comment: Commenter (2339-INGAA) suggests that a lopsided cost-benefit analysis that accounts for the global costs of greenhouse gas (GHG) emissions over a centuries-long time

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<sup>4</sup> Sebastien Elzein, "E&P Capital Expenditures Set to Rise, but Remain Below Pre-Pandemic Levels," Mercer Capital, April 22, 2022. <https://mercercapital.com/energyvaluationinsights/ep-capital-expenditures-set-to-rise-but-remain-below-pre-pandemiclevels/>.

<sup>5</sup> Evercore ISI, 2023 E&P Spending Outlook.

<sup>6</sup> Carolyn Davis, "North American E&P Spend to Increase 14% in 2023; Maintain in Appalachia, Grow in Haynesville," Natural Gas Intel, Jan 19, 2023. <https://www.naturalgasintel.com/north-american-e-maintain-in-appalachia-grow-in-haynesville/>.

horizon, while failing to provide a similarly expansive estimate of the social benefits of energy, overestimates the costs and underestimates the benefits of investments in energy infrastructure. The commenter asserts that the EPA has effectively encouraged such lopsided analysis by submitting comments to Federal Energy Regulatory Commission (FERC) that have urged FERC to use the social cost of greenhouse gas (SC-GHG) in evaluating proposed natural gas pipeline projects under the Natural Gas Act.<sup>7</sup> The commenter notes they have explained in its own comments to FERC, this would lead to a distorted analysis that is biased against the benefits of natural gas, given that FERC's analysis of proposed projects does not quantify the myriad long-term, global social benefits of energy in a similarly wide-ranging manner.<sup>8</sup>

According to the commenter (2339-INGAA), neither EPA's Draft Report nor EPA's RIA contends with this fundamental problem: namely, that if a cost-benefit analysis purports to estimate costs at a global scale and over centuries-long future time horizons, it must do so for benefits as well.<sup>9</sup> The commenter asserts that the EPA must address this problematic asymmetry if it continues to employ SC-GHG estimates—particularly as applied to energy infrastructure projects.

Response II-20-4: To the extent that the commenter references comments submitted by the EPA to another federal agency in a separate and distinct agency action, such comment is out of scope.

The way that the EPA estimated the monetized climate benefits of emission reductions expected from these final rules using estimates of the social cost of methane are explained in detail in the Final Rule preamble in Sections II.C and XVI.E.

The EPA notes that a rule that affects GHG emissions may also affect the production or consumption of goods and services, in which case it could create costs and benefits for businesses and households that either produce or use those goods and services. These costs and benefits are important to include in an analysis of the rule's impacts but are not the result of changes in GHG emissions from the rule and, therefore, it would be inappropriate to try and include them in the SC-GHG used to value changes in GHG emissions. In other words, the SC-GHG is not a measure of social welfare from the consumption of goods and services whose production results in GHG emissions, nor is it intended to capture other positive or negative externalities associated with the production of those goods and services. Similarly, the SC-GHG is not intended to capture the benefits or costs to society from the production and consumption of goods and services associated with regulatory compliance, or the impacts from changes in other emissions that may also occur as a result of regulatory compliance. The SC-GHG is just one component of a larger analysis that includes consideration of other potentially relevant impacts of a policy, including the social costs of compliance, labor market changes, and changes in emissions of other pollutants, as appropriate for the specific analysis. A more detailed response

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<sup>7</sup> See Comments of EPA at 5-6, Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews, FERC Docket No. PL21-3-000 (Apr. 25, 2022); Comments of EPA at 3, Certification of New Interstate Natural Gas Facilities, FERC Docket No. PL18-1-000 (Apr. 25, 2022).

<sup>8</sup> See INGAA April 25, 2022 FERC Comments at 54-55; INGAA January 7, 2022 FERC Comments at 25-27.

<sup>9</sup> Accord Ctr. for Biological Diversity, 538 F.3d at 1198, 1202 (in employing cost-benefit analysis, agency "cannot put a thumb on the scale" by monetizing some "uncertain benefits" but not others).

can be found in the Appendix Chapter of the RTC on the EPA's *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

Comment: Commenters (2393-ODEQ/OSEE), commenting on “super-emitters”, state that monitoring and control costs are expected to display a heavy-tailed data distribution; and EPA’s cost estimates likely significantly underestimate monitoring and control costs by assuming an incorrect data distribution. The commenters note that the heavy-tailed data distribution that characterizes emissions from this sector (and many others) adds complexity to attempts to estimate aggregate emissions from the sector. In contrast, phenomena that display a normal or Gaussian distribution provide simpler approaches because, for example, the mean, median, and mode of the data set are the same. As a result, the sum of the values of all data points may be estimated by multiplying the median value by the total number of data points. However, the commenters assert that this will not work for a heavy-tailed data distribution, because a relatively small number of data points occupying space in the long tail (high end) of the data distribution account for an oversized share of total emissions. They add that the attempts to estimate total emissions by multiplying the median value by the total number of sources will significantly underestimate total sector emissions.

According to the commenters (2393-ODEQ/OSEE), this principle is well understood and various attempts to address this issue are underway in various forums. But a similar phenomenon occurs with regard to costs of control and monitoring. After reviewing several documents released by the EPA, the commenters’ engineers and environmental program specialists noted a similarly troubling aspect of EPA’s attempt to estimate the cost of controls and monitoring. A description of the approach EPA used to estimate costs is reproduced by the commenters below.

The commenters (2393-ODEQ/OSEE) note that the cost analysis presented in the supplemental notice of proposed rulemaking (SNPR) RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components. The first component is a set of representative or model plants for each regulated facility, segment, and control option. The characteristics of the model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. The second component is a set of projections of activity data for affected facilities, distinguished by vintage, year, and other necessary attributes (e.g., oil versus natural gas wells). Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. 87 Fed. Reg. 74712.

The commenters (2393-ODEQ/OSEE) contend that it appears that EPA has inadvertently assumed that the cost of controls and the cost of monitoring follow a normal or Gaussian distribution and, therefore, total costs may be estimated by multiplying median (in this case “model plant”) costs by the total number of facilities of that type. If this is indeed the case, the commenter suggests that the EPA would be making the same error in estimating costs that EPA is trying to avoid when estimating emissions.



Furthermore, the commenters (2393-ODEQ/OSEE) add that the increased cost of implementing appendix K for all monitoring should be factored into the evaluation of the annual costs of the fugitive emissions monitoring and repair requirements.

To implement the appendix K certification program for the camera, training of technicians (section 10), longer monitoring of components due to dwell time rest break requirements (section 9.4 and 9.5), and video storage of leaks (section 9.7.1), it is expected to increase the cost to conduct an optical gas imaging (OGI) fugitive monitoring program at Compressor Stations and Natural Gas Plants when compared to OGI monitoring costs currently. The commenters state that the requirements for a “Senior OGI camera operator” of 1,400 hours seems a high bar to cross and how this affects the cost of future OGI contractors and industry operators should be accounted for in the future cost/benefit of implementing the appendix K OGI monitoring proposed in NSPS OOOOb and EG OOOOc.

The commenters (2393-ODEQ/OSEE) assert that it will take additional time and effort to develop a better estimate of the cost of control and monitoring using a more accurate statistical approach than the one EPA has used in this proposal. Further, they state that the current estimates are likely to substantially understate the costs of monitoring and control. They conclude by stating that modifications to the SNPR are warranted to address these undercounted costs.

Response II-20-5: The EPA disagrees with the commenter’s assertion that the EPA assumes an incorrect data distribution for costs of compliance. The commenter claims that the costs of control follow heavy-tailed distributions but provides no data to support these claims. Please see the Final Rule Preamble at Section VIII.B (How does the EPA evaluate control costs in this final action?) for a detailed discussion of how EPA considers control costs in this rule and the information that it relied on in making its BSER determinations.

With regards to the request that the EPA include the increased cost of implementing the Appendix K protocol for all OGI monitoring in the evaluation of the annual costs of the fugitive emissions monitoring and repair requirements, the EPA is only requiring owners and operators to comply with Appendix K at natural gas processing plants, and not for fugitive emissions components not located at natural gas processing plants. For natural gas processing plants, the November 2021 TSD provides costs for OGI monitoring though not specifically costs for implementing Appendix K at natural gas processing plants. See Chapter 10 (Equipment Leaks from Natural Gas Processing Plants) of the November 2021 Proposal Technical Support Document (TSD).<sup>10</sup>

Comment: Commenter (2359-CEI) states that the EPA estimates that, during 2023-2035, its preferred option (“primary proposal”) will generate \$55 billion in climate benefits, \$13 billion in compliance costs, \$7.2 billion in net compliance costs (i.e. \$13 billion minus \$5.5 billion in recovered product sales), and net benefits of \$48 billion.<sup>11</sup> The proposal thus looks like an amazing deal, with climate benefits exceeding compliance costs by 4.2 to 1 or (factoring in product recoveries) 7.6 to 1. Upon inspection, however, the commenter contends that those

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<sup>10</sup> EPA-HQ-OAR-2021-0317-0166.

<sup>11</sup> RIA, Table 5-4, p. 5-7.

benefits are make-believe, and the proposal would impose enormous costs for undetectably small benefits. The commenter notes that the reductions in climate-related damages, estimated at \$55 billion, account for 100 percent of the proposal's monetized benefits. The vast majority of climate damages are attributed to the direct and indirect effects of global warming. How much warming would the proposal avert? They add that neither the proposal itself nor the accompanying RIA explicitly addresses that question. The commenter suggests that the EPA's proposal is not reasonable if the climate benefits are illusory. They add that an unreasonable regulation may be challenged as arbitrary and capricious.

Response II-20-6: The SC-GHG is the monetary value of the net harm to society from emitting a metric ton of that GHG into the atmosphere in a given year. In principle, the SC-GHG is a comprehensive metric that includes the value of all future climate change impacts (both negative and positive), including changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG, therefore, also reflects the societal net benefit of reducing emissions of the GHG by a metric ton. The SC-GHG is the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations restrain the ability of SC-GHG estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Comment: Commenter (2241-UDNR) states they are concerned that the cost of implementing proposal measures may do much to harm the oil and gas industry's resilience in the state. For example, they note that it may be true that the key components of the proposal will yield nearly \$4.5 billion in net climate benefits a year, with said benefits being enjoyed by all citizens. However, the Proposal would also "require states to reduce methane emissions from hundreds of thousands of existing sources nationwide for the first time"<sup>12</sup> which would require oil and gas operators to retrofit and update existing infrastructure to standards at costs which have not yet been fully quantified. Not only would the compliance costs be passed down to the producers, but the commenter states that it would increase the cost of product recovery. Thus, they note that while the net benefits may be somewhat equitably distributed, the costs would be unevenly borne by the States and oil and gas operators.

Response II-20-7: The EPA disagrees with the commenter's assertion that the compliance costs will significantly harm the oil and gas industry's resilience in the state (Utah), particularly since Commenter's claim is not supported by any specific data or analysis. To the extent that the Final Rule affects states with oil and gas production more than states without oil and gas production, such is the case for all regulated sources across CAA section 111, states that host regulated facilities are indeed more likely to notice impacts. Nonetheless, as explained in further detail below, the EPA has determined that the costs of controls associated with the BSER for the final NSPS OOOOb and EG OOOOc are reasonable. In reaching this determination, the EPA

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<sup>12</sup> 5 SEMPRA, ECA LNG – A World-Class Project to help Power the Global Energy Transition, Sempra Infrastructure, available at: <https://semprastructure.com/news-and-events/spotlight-stories/eca-lng-a-world-class-project-to-help-power-the-global-energy-transition> (2022).

conducted numerous cost analyses, described in detail in Section XII of the November 2021 Proposal, Section IV of the December 2022 Supplemental Proposal, and section XI of the Final Rule, as well as the technical support documents in the docket for this rulemaking. In addition, EPA notes that it estimated the value of product recovery as a result of the Final Rule, in Section 2.5 of the Final RIA, at \$7.4 billion to \$11 billion in 2019\$, with approximately 90% of that product recovery being captured by producers.

Comment: Commenter (2343-NYU School of Law) states that, in the RIA, EPA demonstrates that the December 2022 supplemental proposal sets standards at a level of stringency that is net beneficial, with the monetized benefits alone greatly exceeding the monetized costs.<sup>13</sup> However, the commenter suggests that the EPA makes analytical assumptions that lead it to likely underestimate the full benefits of the December 2022 supplemental proposal.

Commenter (2343-NYU School of Law) provides that, in the RIA, EPA itself acknowledges that “some amount of both benefits and costs would likely continue after 2035,” and “note[s] that toward the end of [their] analytical time horizon, undiscounted net costs are relatively steady from year to year (Table 2-9) while undiscounted monetized climate benefits (Table 3-4) are rising each year.” On this basis, EPA concludes, “It is therefore plausible that significant net benefits would continue in the years after 2035.”<sup>14</sup> EPA additionally estimates that the Supplemental Proposal will reduce 3,500,000 short tons of methane, 920,000–960,000 short tons of volatile organic compound (VOC) emissions, and 37,000–39,000 short tons of hazardous air pollutants (HAP), annually between 2026 and 2035.<sup>15</sup> For VOC and HAP, the annual reductions are all projected to increase between 2026 to 2035. If comparable emissions reductions of these pollutants continue for some number of years after 2035, that would yield significant non-climate benefits. Given these trends in annual costs and benefits and the continuation of the standards past 2035, it is highly likely that the December 2022 supplemental proposal will result in additional benefits after 2035.

The commenter (2343-NYU School of Law) recommends that EPA seek to extend its analysis to consider the likelihood that the standards will reduce emissions beyond 10 years. Even if EPA does not extend its analytical timeframe, it should include a discussion of benefits beyond 2035 as an unquantified benefit. Lastly, while extending the time horizon would better capture the full benefits of its proposed standards, EPA can still find that the standards are cost-beneficial without this information.

Commenter (2355-Constellation Energy) states that EPA must consider unquantified and ancillary benefits. The commenter contends that economic principles and best practices for agency rulemaking dictate that consideration of costs and benefits of any section 111 rule include all quantifiable and unquantifiable, direct and indirect costs and benefits.<sup>16</sup> The commenter notes that Executive Order 12866 governing agency rulemaking provides that “agencies should assess all costs and benefits” of proposed regulatory actions, and, for “significant regulatory action,” must assess “benefits anticipated from the regulatory action (such as, but not limited to,

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<sup>13</sup> RIA, *supra* note 3, at 161–62 tbl.5-4 (projecting net benefits of \$34 billion with a 3 percent discount rate).

<sup>14</sup> RIA, *supra* note 3, at 167.

<sup>15</sup> *Id.* at 64 tbl.3-2.

<sup>16</sup> Indirect benefits may also be called ancillary benefits or co-benefits.

the promotion of the efficient functioning of the economy and private markets, the enhancement of health and safety, the protection of the natural environment, and the elimination or reduction of discrimination or bias).<sup>17</sup> Similarly, guidance from the Office of Management and Budget directs agencies to “look beyond the direct benefits and direct costs of your rulemaking and consider any important ancillary benefits and countervailing risks. An ancillary benefit is a favorable impact of the rule that is typically unrelated or secondary to the statutory purpose of the rulemaking . . . .”<sup>18</sup> Further, EPA’s long-standing practice is to include in a cost-benefit analysis benefits that are not directly intended by the rulemaking.<sup>19</sup>

Commenter (2462-Private Citizen) notes the financial benefits from the new rule, but states that the benefits are an underestimate. The new methane rules provide \$670 million in net benefits, based on detailed analyses.<sup>20</sup> The commenter provides that this number comes from the fact that reducing methane emissions also means recovery of methane for sale, estimated at \$88 million per year. When the financial benefits in climate control, compliance costs and recovery of methane are all considered, they state that the net benefit is \$670 million per year. The commenter adds that this total does not include the substantial cost benefits from reduced illnesses associated with air pollution such as VOCs and particulates known to accompany methane emissions.

Commenter (2353-CrownQuest) suggests that the EPA based this rule on the SCC, as there isn’t even an attempt to quantify the benefits from the calculated VOC and HAP reductions the EPA acknowledges at face value would not justify the costs imposed.

Response II-20-8: The EPA has addressed several of commenters’ points in the Final Rule RIA. First, the EPA extended the nationwide net benefits analysis horizon in the RIA beyond 2035 to 2038 but declined to extend the analysis further due to the significant uncertainties in projected long-run sectoral trends. In addition, the EPA notes that the monetized climate benefits associated with the 2023–2038 CH<sub>4</sub> emission reductions reflect the discounted stream of benefits resulting from those emission reductions over a much longer time horizon (out to 2300). Second, the EPA has added the quantification of the impact of changes in VOC releases via their impact on ozone formation in the Final RIA. However, the EPA is currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations (see Response I-20-3 in Chapter 20 of Volume I of the RTC for more information).

#### 20.1.1.3 Use of the Interim Social Cost of GHGs Under this Action

Comment: Commenter (2292-WV AG, et al) states that the EPA uses flawed measures like the so-called “social cost of carbon” to justify excessive costs that will have real consequences.

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<sup>17</sup> Exec. Order No. 12,866 (Sept. 30, 1993) §§ 1(a), 6(a)(3)(C)(i) (published at 58 Fed. Reg. 51,735 (Oct. 4, 1993)).

<sup>18</sup> White House Office of Management and Budget, Circular A-4 at 26 (Sept. 17, 2003), [https://obamawhitehouse.archives.gov/omb/circulars\\_a004\\_a-4/](https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/).

<sup>19</sup> U.S. Environmental Protection Agency, Guidelines for Preparing Economic Analyses (Dec. 17, 2010), <https://www.epa.gov/sites/default/files/2017-08/documents/ec-0568-50.pdf>.

<sup>20</sup> EPA 2022 Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review EPA-452/R-22-007.

According to the commenter, the purported climate benefits could fall anywhere within a breathtakingly broad range—from \$19 billion to \$130 billion.<sup>21</sup>

Response II-20-9: As explained in the Proposed Rule and Final Rule, the assessment of benefits described in the RIA is presented solely for the purposes of complying with E.O. 12866 and providing the public with a complete depiction of the impacts of the rulemaking. It is wholly distinct from the BSER determinations in this Final Rule, which are based on the statutory factors the EPA is required to consider under section 111(a) of the CAA (including cost, energy requirements and non-air quality health, and environmental impacts).

The distributions of SC-GHG estimates reflect uncertainty in key model parameters chosen by the Interagency Working Group (IWG) such as the sensitivity of the climate to increases in greenhouse gas emissions, as well as uncertainty in default parameters set by the original model developers. The IWG selected SC-GHG values for use in regulatory analyses. For each emissions year, four values are recommended. Three of these values are based on the average SC-GHG from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. In addition, there is extensive evidence in the scientific and economic literature on the potential for lower-probability, but higher-impact outcomes from climate change, which would be particularly harmful to society and thus relevant to the public and policymakers. The fourth value is thus included to represent the marginal damages associated with these lower-probability, higher-impact outcomes. Accordingly, this fourth value is selected from further out in the tail of the distribution of SC-GHG estimates; specifically, the fourth value corresponds to the 95th percentile of the frequency distribution of SC-GHG estimates based on a 3 percent discount rate. The central value is the average of SC-GHG estimates based on the 3 percent discount rate. For purposes of capturing uncertainty around the SC-GHG estimates in regulatory impact analysis, the IWG emphasizes the importance of considering all four SC-GHG values.

Comment: Commenter (2403-PAO) states that the EPA estimated the climate benefits of methane emission reductions expected from this Proposed Rule using the “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)” published in February 2021 by the Interagency Working Group (IWG) on the SC-GHGs. However, they note that EPA does not consider the many benefits of oil and natural gas and how EPA’s actions may have broad implications here in the U.S. and abroad. For example:

- Oil and natural gas play an indispensable role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible,<sup>22</sup>
- Oil and natural gas companies play a significant role in state economies, contribute to state and local taxes, and royalties that pay for schools, universities, roads, and various

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<sup>21</sup> See EPA, REGULATORY IMPACT ANALYSIS OF THE SUPPLEMENTAL PROPOSAL FOR THE STANDARDS OF PERFORMANCE FOR NEW, RECONSTRUCTED, AND MODIFIED SOURCES AND EMISSIONS GUIDELINES FOR EXISTING SOURCES: OIL AND NATURAL GAS SECTOR CLIMATE REVIEW 17 (Nov. 2022), <https://bit.ly/3X6ltYQ>.

<sup>22</sup> American Fuels and Petrochemical Manufacturers, website information on May 5, 2022.

essential services, provide good paying direct and indirect jobs, and improve the communities they work and reside in,<sup>23</sup>

- Oil and natural gas companies developing U.S. resources can provide the world affordable, reliable natural gas and crude oil in the most environmentally responsible manner as compared to oil and gas development elsewhere in the World, and
- Clean-burning natural gas has enabled the U.S. to become the global leader in greenhouse gas emissions reductions.<sup>24</sup>

The commenter (2403-PAO) requests that EPA factor into its Social Cost of Carbon (SCC) cost benefit analysis the many benefits (as described above) of oil and natural gas.

Response II-20-10: A rule that affects GHG emissions may also affect the production or consumption of goods and services, in which case, it could create costs and benefits for businesses and households that either produce or use those goods and services. These costs and benefits are important to include in an analysis of the rule's impacts but are not the result of changes in GHG emissions from the rule and therefore, it would be inappropriate to try and include them in the SC-GHG used to value changes in GHG emissions. In other words, the SC-GHG is not a measure of social welfare from the consumption of goods and services whose production results in GHG emissions, nor is it intended to capture other positive or negative externalities associated with the production of those goods and services. Similarly, the SC-GHG is not intended to capture the benefits or costs to society from the production and consumption of goods and services associated with regulatory compliance, or the impacts from changes in other emissions that may also occur as a result of regulatory compliance. The SC-GHG is just one component of a larger analysis that includes consideration of other potentially relevant impacts of a policy, including the social costs of compliance, labor market changes, and changes in emissions of other pollutants, as appropriate for the specific analysis.

Comment: Several commenters weighed in on EPA's decision to use the interim Social Cost of Methane (SCM) established in the IWG on SC-GHGs recently published Technical Support Document (2021 TSD)<sup>25</sup> in evaluating the costs and benefits of the Supplemental Proposal.

Commenters (2212-UCS, 2410-CA AG et al, 2343-NYU School of Law, 2355-Constellation Energy, 2397-U.S. Climate Alliance) support EPA's decision to use the interim SCM established in the IWG recently published 2021 TSD, and express support for the proposal's accompanying draft report, *The Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Examples of some of the high-level support positions are included in the following paragraphs.

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<sup>23</sup> <https://oerb.com/economic-impact/>; <https://www.txoga.org/2021eeir/>; [https://www.nmoga.org/natural\\_gas\\_and\\_oil\\_industry\\_critical\\_to\\_new\\_mexico\\_post\\_pandemic\\_recovery?utm\\_campaign=\\_icymi\\_new\\_report&utm\\_medium=email&utm\\_source=nmoga](https://www.nmoga.org/natural_gas_and_oil_industry_critical_to_new_mexico_post_pandemic_recovery?utm_campaign=_icymi_new_report&utm_medium=email&utm_source=nmoga).

<sup>24</sup> Global CO<sub>2</sub> Emissions in 2019, IEA, February 2020; U.S. Energy-Related Carbon Dioxide Emissions, 2019, U.S. Energy Information Administration (EIA), September 2020.

<sup>25</sup> EPA-HQ-OAR-2021-0317-0005, Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimate Under Executive Order 13,990 (Feb. 2021) (hereinafter, "2021 TSD").

Commenter (2397-U.S. Climate Alliance) applauds the inclusion and utilization of updated estimated values for the SC-GHG in the proposal's accompanying draft report, the *Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. The commenter asserts that properly accounting for the societal costs of a changing climate is key to crafting effective state and federal policies and achieving our shared net-zero climate goals. EPA's updated approach is particularly timely as we continue to await action from the IWG on the *Social Cost of Greenhouse Gases*, reestablished by President Biden in January 2021, whose current interim estimates — based on work conducted between 2010 and 2016 — are outdated and substantially underestimate climate costs.

Commenter (2355-Constellation Energy) asserts that, only with a full accounting of the damages associated with incremental emissions of methane and other GHGs to property, human health, agricultural resources, and natural resources can the real cost of climate inaction be understood. They recommend that Federal agencies incorporate the SC-GHGs in all relevant areas of decision-making including regulatory analyses, and the SCM is the appropriate value to use in conducting benefit-cost analyses and estimating the climate impacts of policies that affect methane emissions. They also believe that it is appropriate for the RIA for the Supplemental Proposal to consider EPA's sensitivity analysis of the SCM that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine.<sup>26</sup> The commenter adds that they support EPA's work on this important undertaking while the IWG's work continues, since underestimates of the SCM and other GHGs result in inadequate regulation of GHG emissions and market disincentives for investment in cleaner energy sources. As a critical member of the IWG, the commenter states that the EPA is an agency with technical and economic expertise that makes it well-suited to establish a SC-GHG.

Commenter (2212-UCS) states that EPA has taken an important and necessary step by issuing the draft Report on the *Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* in September 2022<sup>27</sup> and incorporating those findings as a sensitivity analysis within the supplemental's RIA. The commenter notes that the separate and ongoing IWG process is important for standardizing an update to the intergovernmental SC-GHG values; however, while the IWG process continues it is important that EPA still incorporate its understanding of numerous updates in science, economics, and best practice as an additional point of context given the relevance and timeliness of the issue to this rulemaking. While EPA makes clear that the rulemaking is not predicated on these supplemental values, the rulemaking benefits from their incorporation to provide fuller context for the potential impact of this rule.

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<sup>26</sup> U.S. Environmental Protection Agency, Regulatory Impact Analysis of the Supplemental Proposal for Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review 189 (Nov. 2022); see also U.S. Environmental Protection Agency, Supplementary Material for the Regulatory Impact Analysis for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, September 2022, [https://www.epa.gov/system/files/documents/2022-11/epa\\_scghg\\_report\\_draft\\_0.pdf](https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf).

<sup>27</sup> U.S. EPA, EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, September 2022 (Docket ID No. EPA-HQ-OAR-2021-0317).

Commenter (2343-NYU School of Law) believes EPA properly relies on the interim estimates of the SCM from the IWG in the RIA. They note that the EPA also includes a sensitivity analysis of the monetized climate benefits with updated estimates of the SCM [SC-CH<sub>4</sub>] from EPA's draft September 2022, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. EPA finds that "for all emissions years the range of the climate benefits resulting from this sensitivity analysis is higher in magnitude than the monetized climate benefits using the IWG's recommended interim SC-CH<sub>4</sub> estimates."<sup>28</sup> The commenter states that the September 2022 update faithfully implements the roadmap laid out in 2017 by the National Academies of Sciences, and, while it represents a significant increase over the climate-damage valuations from the IWG, that increase is consistent with the widespread economic consensus, including the IWG's own repeated recognition that its valuations are underestimates.<sup>29</sup>

Therefore, the commenter (2343-NYU School of Law) suggests that the monetized climate benefits in the RIA are likely lower-bound estimates, and EPA underestimates the December 2022 supplemental proposal's associated climate benefits. Indeed, the commenter notes that even the higher estimates from the September 2022 report are conservative.<sup>30</sup>

Commenters (2410-CA AG et al) support the use of the interim value for SCM established in the 2021 TSD as representing the best available estimate of the long-term cost to society of increasing methane emissions now.<sup>31</sup> Although the IWG is currently in the process of reviewing comments on how to improve and update the SC-GHG, including the SCM,<sup>32</sup> for now the interim value for SCM established in the 2021 TSD represents the best available estimate of the long-term cost to society of increasing methane emissions now.<sup>33</sup> Moreover, the commenter notes that the SC-GHG does not dictate the outcome of any specific agency rulemaking, including this one. Here, EPA considers the SCM in evaluating the costs and benefits of the Supplemental Proposal,<sup>34</sup> but nowhere suggests that those values were used to determine the best system of emission reduction (BSER) for the oil and natural gas sector, or that they will be determinative of its ultimate decision.<sup>35</sup> The commenter adds that the SCM is simply one additional tool for monetizing some of the benefits of a regulation that would otherwise be non-monetized, not a thumb on the scale of agency cost-benefit analyses.

Response II-20-11: EPA thanks the commenters for their supportive comments. A detailed response to comments pertaining to EPA's draft September 2022, *Report on the Social Cost of*

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<sup>28</sup> RIA, *supra* note 3, at 191.

<sup>29</sup> See NAT'L ACADS. SCIS., ENG'G & MED., VALUING CLIMATE DAMAGES: UPDATING ESTIMATION OF THE SOCIAL COST OF CARBON DIOXIDE (2017); INTERAGENCY WORKING GROUP, TECHNICAL SUPPORT DOCUMENT: SOCIAL COST OF CARBON, METHANE, AND NITROUS OXIDE INTERIM ESTIMATES UNDER EXECUTIVE ORDER 13990 4 (2021).

<sup>30</sup> EPA, EPA EXTERNAL REVIEW DRAFT OF REPORT ON THE SOCIAL COST OF GREENHOUSE GASES: ESTIMATES INCORPORATING RECENT SCIENTIFIC ADVANCES 2 (2022).

<sup>31</sup> See RIA, *supra* n.146, at 65–66.

<sup>32</sup> See Notice of Availability and Request for Comment on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13,990," 86 Fed. Reg. 24,669, at 24,670 (May 7, 2021).

<sup>33</sup> See RIA, *supra* n.146, at 65–66.

<sup>34</sup> RIA at 3.2.

<sup>35</sup> 87 Fed. Reg. at 74,843.



*Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* can be found in the Appendix of this RTC.

Comment: Several other commenters (2218-TCEQ, 2227-WEA, 2237-ICND, 2254-PBPA, 2301-U.S. Chamber of Commerce, 2359-CEI, 2399-GPA, 2339-INGAA) oppose the use of the use of the interim value for SCM established in the 2021 TSD and in the proposal's accompanying draft report, *The Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Examples of some of the high-level opposition positions are included in the following paragraphs.

Commenter (2359-CEI) notes that, although the EPA has separately published and invites comment on new SC-GHG estimates incorporating recent research,<sup>36</sup> the proposal's benefit calculations rely on the February 2021 TSD, which the agency considers "the most appropriate estimate of the SC-CH<sub>4</sub> until revised estimates have been developed reflecting the latest, peer-reviewed science."<sup>37</sup> As a general observation, the commenter believes that the SC-GHG estimates are too speculative, and too easily manipulated for political purposes, to inform regulatory decisions.

Commenter (2254-PBPA) states that the EPA's approach does not consider the fact that domestic oil and gas production often has a lower carbon-footprint than the energy sources that would otherwise be used in the absence of such production. They state that the proposed EGs could result in accelerating the abandonment of existing well sites, but EPA has not quantified the additional emissions that could result from having to source energy from alternative locations.

The commenter (2254-PBPA) contends that the EPA's social cost of carbon (SCC) report showcases the lack of fair consideration and myopic use of scientific information. The report declares eliminating all U.S. oil and gas production and transportation would increase the U.S. economy between \$600 billion to \$3 trillion per year (3-10% of the U.S. GDP). Never does the report consider the benefits hydrocarbon production provides to our society. The extrapolated benefit of eliminating all oil and gas production shows the lack of real-world understanding in academia. The EPA should instead acknowledge how the U.S. increased its GDP while decreasing GHG emissions over the past ten years. At the same time, the commenter reports that states like Texas require weatherization and operations in cold and hot weather events to save lives, economic output, and prosperity. According to the commenter, making a rule that creates hard economic loss while not fully considering the ramifications of said rule sets a dangerous precedent for society.

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<sup>36</sup> EPA, Supplementary Material for the Regulatory Impact Analysis for the Supplemental Proposed Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, September 2022, [https://www.epa.gov/system/files/documents/2022-11/epa\\_scghg\\_report\\_draft\\_0.pdf](https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf) (hereafter External Review Draft).

<sup>37</sup> 87 FR 74713.

Commenter (2399-GPA) states that the EPA recognizes that the SCM interim values, released pursuant to Executive Order 13990,<sup>38</sup> have not been finalized. They add that they and other commenters have not yet had responses to their comments identifying significant deficiencies associated with these interim values.<sup>39</sup> Indeed, the commenter asserts that recognizing the values require further scientific study, EPA and other agencies have begun an expert peer review of the administration's social cost analyses.<sup>40</sup> According to the commenter, until that peer review process is conducted and subject to public review and comment, it is inappropriate for EPA to consider the interim values to support its Supplemental Proposed Rule.

Commenter (2237-ICND) suggests that the EPA's asymmetrical cost benefit analysis for the Supplemental Proposal relies on an ideological global "social cost of greenhouse gas" that purports to confer benefit on the global public that consequently are to be achieved through a rule the costs of which are to be borne solely by the U.S. public. However, the commenter notes that when correctly considering only the domestic social cost of GHGs, the Supplemental Proposal will not benefit the U.S. and will instead impose a net cost on the U.S. public of \$7.4 billion (in 2019 dollars). Less than 15% of the global social cost of GHG benefits claimed by EPA for this proposed rule will accrue to the U.S. public, which would nonetheless pay the full tab to subsidize these claimed global benefits. The commenter adds that the EPA is not authorized by the CAA to rely on cumulative global climate benefits to justify the costs imposed solely on North Dakota and the nation by the Supplemental Proposal. The commenter asserts that the EPA's authority to promulgate Section 111 regulations is not based in cumulative ideologically based global climate benefits, but rather upon technically based "air pollution prevention and control programs." 42 U.S.C. § 7410(b)(4).

Commenter (2218-TCEQ) states that the RIA and supplemental analysis are flawed because the SCM metric used significantly inflates the climate benefits resulting from this rule. The commenter suggests that the SCM method EPA uses is artificially high and relies on unrealistic assumptions on the direct benefit to global climate due to the methane reductions anticipated by this rule. The commenter adds that the methane emission reductions achieved are a fraction of the emissions of GHGs globally that must be reduced to stabilize global temperatures. Thus, they say that the EPA's metric of climate benefits relies primarily on presumed efforts that will occur internationally and not on the mitigation efforts of this proposal. The commenter states that although the EPA claims the monetized benefits analysis using a revised SCM is "entirely distinct" from the proposed statutory BSER determinations, this exercise unjustifiably inflates the climate benefits of the proposed regulatory scheme. According to the commenter, the EPA attempts to justify burdensome requirements across all oil and gas sources by establishing an extremely high cost per ton of methane. The commenter notes that, if the benefits of the regulation are the avoided cost of GHG emissions on the climate, EPA admits in their sensitivity analysis that these benefits will not be realized by imposition of the regulations in the 2023 to 2035 timeframe.

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<sup>38</sup> Exec. Ord. 13,990, Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, 86 Fed. Reg. 7,037 (Jan. 25, 2021).

<sup>39</sup> GPA Midstream, Comments Submitted on 86 Fed. Reg. 24,669 (May 7, 2021) (submitted June 21, 2021). GPA Midstream incorporates those comments here by reference. A copy is attached as Exhibit B.

<sup>40</sup> <https://www.epa.gov/environmental-economics/scghg-td-peer-review>

Commenter (2339-INGAA) states that, at the outset, the EPA’s use of its own SC-GHG estimates is contrary to Executive Order (E.O.) 13990. That order re-established the IWG, specified its membership (including EPA), and set out a process for the IWG to follow in establishing SC-GHG figures.<sup>41</sup> The order states that the IWG “shall” proceed by publishing interim SC-GHG figures within 30 days and final SC-GHG figures by January 2022, and also directs the IWG to provide recommendations regarding “a process for reviewing and, as appropriate, updating” the SC-GHG estimates and the underlying methodologies on which they are based.<sup>42</sup> Most critically, E.O. 13990 states that “agencies shall use” the IWG’s interim SC-GHG estimates “when monetizing the value of changes in greenhouse gas emissions.”<sup>43</sup>

Here, the commenter (2339-INGAA) asserts that the EPA has acted contrary to those instructions by issuing and employing its own entirely different SC-GHG estimates. EPA’s course is not only contrary to E.O. 13990’s instruction that executive agencies, including EPA, “shall use” the IWG’s interim figures (i.e., not other estimates of their own choosing), but is puzzling given that EPA itself is a member of the IWG. According to the commenter, the order clearly articulates a process for the IWG to follow, which does not include individual member agencies issuing and employing their own SC-GHG estimates. The commenter suggests that the EPA’s proper course is to work as a member of the IWG to assist in that ongoing group process, not to promulgate its own unilateral issuances in contradiction to the process contemplated in E.O. 13990.

According to the commenter (2339-INGAA), EPA attempts to justify its approach by noting that the IWG invited agencies to use different discount rates in sensitivity analyses for RIAs.<sup>44</sup> But they contend that the EPA went well beyond merely using alternative discount rates in its sensitivity analysis—it issued its own entirely different SC-GHG estimates, based on significant methodological changes at every step of the analytic process. It is one thing to conduct a sensitivity analysis that considers lower and higher discount rates,<sup>45</sup> and quite another to issue a new SC-GHG analysis that gives the clear impression of being intended to supersede and replace the IWG’s work product in toto. The commenter asserts that the EPA has accordingly acted contrary to E.O. 13990’s instructions.

The commenter (2339-INGAA) contends that the EPA’s decision to issue its own SC-GHG estimates that are based on significantly altered methodologies and depart drastically upward from the IWG’s interim estimates threatens to bring back the cross-agency inconsistency the IWG was created to alleviate. Despite its status as a member of the IWG itself, the commenter states that the EPA has essentially re-created the situation that existed in 2008, when the IWG

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<sup>41</sup> 86 Fed. Reg. 7,037, 7,040-41 (Jan. 25, 2021).

<sup>42</sup> *Id.* at 7,040.

<sup>43</sup> *Id.*

<sup>44</sup> RIA at 68; see Interim TSD at 4, 21.

<sup>45</sup> The IWG’s Interim TSD suggested that agencies could use lower discount rates in sensitivity analyses, without mentioning the possibility of also using higher discount rates. See Interim TSD at 4, 21. INGAA disagrees with that one-sided focus. The purpose of a sensitivity analysis is to see how plausible alternative inputs and assumptions would affect a cost-benefit analysis; it therefore makes sense to consider an ample range of reasonable alternative inputs in such a sensitivity study. Cf. Circular A-4, Regulatory Analysis at 41 (Sept. 17, 2003), <https://tinyurl.com/mtvsn3jx> (hereinafter Circular A-4 (2003)). Given the credible arguments for higher discount rates in this context—and especially in light of the fundamentally normative and policy-based nature of the choice of discount rate—it would be reasonable to consider both higher and lower discount rates in a sensitivity analysis. See *infra* Part II.C.

was first convened, including, as it apparently did then, endorsing SC-GHG values higher than those used by other agencies. If EPA's rationale is accepted, the commenter states that other agencies might follow suit, adding further to the inconsistency and confusion.

Commenter (2339-INGAA) notes that the EPA's departure is particularly puzzling given the absence of any clear reason for doing so. EPA's only stated rationale for issuing its own completely revised SC-GHG estimates in spite of the ongoing IWG process is to provide alternative values for a sensitivity analysis.<sup>46</sup> But that sensitivity analysis simply delivers the unsurprising verdict that regulations to reduce GHG emissions, which EPA has already determined deliver more benefits than costs, perform even better in a cost-benefit analysis when a higher value is placed on GHG emissions reductions.<sup>47</sup> Respectfully, it is obscure how this finding is expected to improve the quality or informativeness of EPA's RIA for the present rulemaking.<sup>48</sup> Interested parties can only infer that EPA's issuance of its own SC-GHG estimates may signal a broader intent to deviate from the IWG's estimates in the future.

Response II-20-12: A detailed response to comments pertaining to EPA's draft September 2022, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* and the general use of SC-GHG estimates in policy analysis can be found in the Appendix of this RTC.

Comment: Commenter (2179-KIOGA) states that, in addition, in the cost benefit analysis, the EPA uses an interim SCC value of \$51 per ton. The \$51 per ton SCC includes global climate change impacts that are outside the jurisdiction of the EPA. We believe the EPA should use the most recent SCC of \$7 per ton that was limited to climate change impacts within the U.S. The commenter adds that they also find it disconcerting that the EPA references conflicting global warming (GWP) potentials for methane (80, 30, 29.8, 27.2, and 25) throughout the proposal instead of using the established GWP used for emissions inventory purposes.

Response II-20-13: A detailed response regarding the use of global SC-GHG estimates can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

Comment: Commenter (2401-State of Wyoming) states Wyoming's DEQ and WOGCC have a long history of responsibly regulating the oil and gas industry. The commenter provides a complete regulatory process, from permitting to plugging. Wyoming consistently ranks among the top states for oil and gas production from onshore federal minerals. Approximately 65 percent of the total oil production and 79 percent of the total gas production in the state is

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<sup>46</sup> RIA at 78 ("While [the IWG] process continues, the EPA is taking the opportunity in this RIA to present a sensitivity analysis of the monetized climate benefits of this proposed action using an updated set of SC-CH<sub>4</sub> estimates, newly developed by EPA . . ."); see also Supplemental NOPR, 87 Fed. Reg. at 74,843 (similar).

<sup>47</sup> See generally RIA at 189-96.

<sup>48</sup> The purpose of a sensitivity analysis is to see how changing assumptions may affect a cost-benefit analysis. See Circular A-4 (2003) at 41. As Circular A-4 (2003) explains (and common sense confirms), the primary value of such an exercise is to find "switch points"—critical parameter values at which estimated net benefits change sign or the low cost alternative switches." Id. EPA's sensitivity analysis does not point to any such "switch points." Instead, the sensitivity analysis seems largely oriented toward buttressing conclusions EPA has already reached.

produced from federal minerals. Oil and gas production takes place in 21 of Wyoming's 23 counties and directly employs over 9,000 people. Taxes on production contribute over a billion dollars annually to state and local governments.

Commenter (2401-State of Wyoming) states the majority of Wyoming oil and gas producers are not multinational companies and the additional level of federal regulations is duplicative. The costs levied on the producers and our agencies far outweigh the environmental benefit. This is particularly true in this proposal since EPA does not provide an accurate or thorough cost and benefit analysis. This proposal will have a disproportionate effect on Wyoming producers as a whole, but particularly on the small operators of stripper wells. In addition, the supplemental proposal places onerous implementation requirements upon DEQ's Air Quality Division given the massive increase of affected facilities and the corresponding mountain of additional requirements pertaining to compliance, permitting, emissions inventories, the development of State plans and other air quality aspects under Wyoming's primacy, making implementation infeasible. The scale of impact on the people of Wyoming from impractical and burdensome new regulations on the oil and gas sector cannot be overstated.

Commenter (2401-State of Wyoming) notes in evaluating the economic impacts, EPA utilizes the social cost of carbon, methane, and nitrous oxide among other asserted social benefits. These societal benefit values are necessary to justify a rule that costs more to comply with than it ends up benefitting. What is left out of the economic analysis are costs to society resulting from the proposed rule, with these costs being born by local communities and their families, schools, and budgets of these local governments. Not only will society lose the benefits of royalties, taxes, and jobs that are lost when wells are prematurely shut in, but also by incurring increased prices to all Americans for transportation fuel, heating their homes, food and all other items we use that are impacted by increased fossil fuel prices. The premature shut in of wells results in one of two outcomes: Either oil and gas prices will increase or will be made up in other countries. Society loses by paying higher costs or the environmental impact of shifting production to nations that do not produce oil/gas under the same regulatory standards found in the states. Simply put, the people of Wyoming and the US lose. If EPA uses societal benefits to justify the economic impact of this rule it should also use the societal costs to conduct a full and complete economic analysis, including localized impacts.

Response II-20-14: The EPA disagrees with the commenter's assertion that the costs of compliance with the Final Rule outweigh the environmental benefits, for the reasons explained in detail in the Final Rule Preamble, Section VIII.B. The commenter provides no specific data or analysis to contest the EPA's assessment, as presented in the Final RIA. The commenter makes general, unsupported claims about premature shut in of wells and increasing commodity prices, but EPA's analysis suggests that the overall impacts of the rule on production and prices will be small (see Response II-20-2).

In response to the comment that the December 2022 Supplemental Proposal places onerous implementation requirements upon DEQ's Air Quality Division, the EPA notes that the Information Collection Request (ICR) and supporting statements for the November 2021 Proposed Rule and the December 2022 Supplemental Proposal included detailed estimates of the time and resources required by state agencies to develop and implement the EGs. Similar to the

claims about cost of compliance, the commenter did not provide any specific comments on that analysis [or offer any information that might change the analysis]. These impacts are also contained in the ICR and supporting statements for the December 2022 Supplemental Proposal and the final rule. With regard to the EPA's estimated reporting and recordkeeping burden for the December 2022 Supplemental Proposal, see the ICR Supporting Statements located at Document ID Item Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO and NSPS OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc), for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. Updated ICR Supporting Statements for this final action are also located in Docket ID No. EPA-HQ-OAR-2021-0317.

The final rule also includes changes that will reduce the burden on state agencies and sources subject to standards developing in accordance with the emission guidelines. For example, for the NSPS OOOOb, the EPA has concluded that only sources constructed, modified, or reconstructed after the date of the Supplemental Proposal (December 6, 2022) should be considered new sources for the purposes of NSPS OOOOb. Changing this date to December 6, 2022, from the November 15, 2021, reduces the number of existing new sources that will need to comply with NSPS OOOOb, thereby allowing more time to plan and meet implementation challenges. For details, please see discussion in section IX (Interaction of the Rules and Response to Significant Comments Thereon), subsection A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the final rule preamble. The EPA has also provided an alternative compliance timeline in the NSPS OOOOb final rule for process controllers and pumps required to meet a zero-emission standard (i.e., final rule allows up to one year from the publication date of the final rule). See section XI.D.4 (Compliance dates) of the final rule preamble for a discussion on the compliance dates finalized for process controllers (which also applies for pumps).

In addition, for the EG OOOOc, the EPA is finalizing a compliance timeline of 36 months from the deadline for state plan submittals, which provides owners and operators of designated facilities time to plan and meet any increased implementation demands. When the compliance timeline of 36 months is considered in conjunction with the state plan submittal deadline of 24 months, that means that sources could have up to 5 years between when the EG are final and when they are required to fully comply with the applicable standards of performance. The EPA believes that any concerns with the planning and implementation of requirements, which commenters speculate could be an issue, would likely be addressed by industry and regulators in that timeframe. See section XIII.E.3 (Compliance timelines) of the final rule preamble for EPA's response to comments regarding the compliance timeline required under the EG.

#### 20.1.1.4 Supplemental Proposal is not Cost-Effective

Comment: Several commenters (2314-Miller Energy, 2254-PBPA, 2220-WDEQ, 2200-NuEnergy, 2179-KIOGA, 2283-Endeavor Energy, 2252-PAW) assert that the supplemental proposal is not cost-effective, unfairly impacts older, existing operations and small businesses, and/or provide references supporting the increased costs. Examples of comments are provided in the following paragraphs.

Commenter (2314-Miller Energy) notes that the oil-and-gas industry is unique from most in the fact that the industry does not have the ability to dictate selling price. Without an ability to push the cost of increased regulatory requirements downstream, many operators will be unable to offset the capital-investment costs for the proposed monitoring equipment. The commenter urges EPA to consider this factor when considering the cost-benefit analysis for each production tier.

Commenter (2254-PBPA) states that the proposed rule is a massive expansion of NSPS OOOOa's requirements, especially regarding recordkeeping, and EPA significantly underestimates the compliance costs. The commenter recommends that EPA develop recordkeeping requirements based on critical operations rather than a one-size-fits-all box. The commenter believes that EPA's recordkeeping estimate is a significant underestimation. The commenter asserts that the estimated effort required to complete annual reports is likely to be much more intensive than the estimated hours of recordkeeping, especially by smaller operators and small businesses that make up a large portion of the EG OOOOc facilities. The commenter states that this rule is complex and forces a diverse group of operations and sites into a one-size-fits-all box. The commenter notes that EPA collected data from NSPS OOOOa for over 12 years but does not cite this data or its effect on targeted facilities' emissions once in the entire rule.

Commenter (2220-WDEQ) asserts that the proposed NSPS OOOOb many new requirements affect nine different types of equipment or processes at oil and natural gas well sites, six different types of equipment or processes at natural gas gathering and boosting compressor stations, six different types of equipment or processes in the natural gas processing segment, and five different types of equipment or processes in the transmission and storage segment. These requirements come with expensive control and compliance costs that operators will have to absorb.

The commenter (2220-WDEQ) contends that even more problematic, however, is the manner in which the new requirements in EG OOOOc mirror many of the requirements in NSPS OOOOb. The commenter states that there are exorbitant and even infeasible costs associated with retrofitting certain control requirements on all existing sources considered affected facilities under the rule. Furthermore, the definitions of such affected facilities have also been expanded for many different types of equipment. The commenter notes that the number of existing facilities in Wyoming that would have to undergo costly retrofitting procedures, in addition to the increased monitoring and compliance burdens, would be massive. At this time, it is impossible to know exactly what the economic impacts would be to operators and the feasibility of continuing their operations and retaining employees, but it is reasonable to assume that they would be significant. There are several additional areas of concern pertaining to the potentially infeasible costs associated with the proposed requirements in EG OOOOc:

- Smaller operators might incur the expense of a third-party contractor to even determine which facilities on their sites are subject to OOOOc requirements.
- The massive increase in affected facilities and required frequency of inspections will require much more driving time to complete all of the necessary inspections, resulting in the unintended consequence of creating more vehicle emissions.
- Completing each inspection will require significantly more time from both operators and state compliance staff – and the overall number of inspections will jump significantly.

- The cost to hire qualified third-party contractors to perform some of the OGI fugitive emissions monitoring required under the supplemental proposal will be significant and infeasible for some smaller operators. Furthermore, it's possible that contractor costs will escalate from current levels due to the increased demand.
- There are a limited number of qualified Senior OGI camera operators based on the requirements of Appendix K and the process of achieving such a qualification is very lengthy.
- Operators will generally have to dedicate more time and resources to performing OGI inspections, which will potentially consume available resources that would otherwise be dedicated to performing ongoing compliance duties. As a result, it is possible that operators will not be able to make repairs in as timely of a manner, resulting in increased emissions. This would appear to be an unintended consequence of the inordinate workload associated with the compliance requirements in the supplemental proposal.

Commenter (2200-NuEnergy) states that the EPA is not justified in proposing new regulations and capital investments to reduce emissions if the target is moved every 2 or 4 years. The commenter asserts that the proposed regulations unfairly penalize small businesses who made capital investments over the last several years to meet regulatory standards only to have new proposed regulations before promised recovery of initial capital investments. The commenter disagrees with EPA using a static \$3.13 per thousand cubic feet (MCF) for their economic analysis. The commenter notes that EPA does not release equations, variables, documentation, references and/or assumptions to determining the cost effects of capital investments, operational changes, increased monitoring, contract labor and interrupted production to improving the reductions in hydrocarbon emissions, yet the EPA is free to assume their estimations and assumptions are industry standards for the cost benefit analysis.

The commenter (2220-WDEQ) states that the industry cannot sustain regulatory costs at the current \$74 per barrel and \$2.44 per mcf of natural gas and the consequences are unknown when oil and natural gas prices drop to \$35 per barrel of oil and \$1.50 per million standard cubic foot (mscf) of natural gas.

Further, the commenter (2220-WDEQ) questions EPA's determination that the proposed regulations are cost effective. The commenter notes that EPA did not consult small businesses, and that all production operations are not equal. The commenter questions EPA's process and qualifications to make this determination.

Finally, the commenter (2220-WDEQ) notes that EPA used the mid-2021 economic conditions as a basis for cost benefit analysis to evaluate the anticipated costs to owners and operators. The commenter asserts that their mid-2021 financial conditions have changed, that warrants a re-evaluated cost benefit analysis.

Commenter (2179-KIOGA) provides examples of Kansas small oil and gas companies' NSPS OOOOa compliance costs in Table 2 of their comment letter. [Table 2. Compliance Activities and Costs required by NSPS OOOOa.] The commenter states that operating costs will increase from Leak Detection and Repair (LDAR) survey costs, reporting costs, and additional capital investment to meet emissions reductions.



Further, the commenter (2179-KIOGA) asserts that projects in Kansas and other areas in the U.S. will not realize an economic benefit for developing compliance programs. The commenter notes that EPA is expecting owners and operators to capture methane and use the sales to offset compliance costs. The commenter contends that most of the gas that is not being sold today costs too much for owners and operators to collect, process, transport, and sell into the natural gas market. If projects to collect, process, and sell gas were economically attractive, companies would have already made the investment. The commenter notes that many wells drilled and produced in Kansas have associated gas that needs to be purified to make it pipeline quality, which is a significant investment for a small volume of produced gas.

Additionally, the commenter (2179-KIOGA) reports, according to Energy Information Administration (EIA), the Henry Hub contract price for natural gas is expected to average \$4.90/Mcf in 2023. The commenter performed Monte Carlo simulations around expected Kansas gas production, gas quality, compliance cost, operating cost, and product pricing. The outcome of their simulations shows that none of the scenarios are profitable (positive Net Present Value (NPV)) and any management team would reject the investment opportunity. The commenter asserts that every well drilled will only have additional compliance costs added and no economic benefit will be realized. The commenter states that this is another example where a Federal Agency issues a national level regulation without considering the impact across the country. EPA's "one size fits all" regulation format failed to consider local conditions.

Commenter (2283-Endeavor Energy) requests that EPA withdraw its proposed EG OOOOc requirements and separately propose more appropriate requirements for existing sources once it has had the opportunity to gain insights from the implementation of NSPS OOOOa and NSPS OOOOb (if finalized). The commenter recommends that EPA craft EGs that reflect the realities of older, existing sources as required by the Clean Air Act (CAA).

The commenter (2283-Endeavor Energy) notes that EPA is presently proposing essentially identical requirements for both new and existing sources. As EPA is aware, the commenter notes that existing sources make up a much larger body of sources as compared to new, modified, or reconstructed sources subject to NSPS requirements. This is true both as a total number of sources, and as a percentage of most operators' facilities. For example, the commenter notes that their well sites are existing sources under the proposed definitions, as are about 90 percent of their tank batteries. Beyond just the sheer numbers of additional sources that will be impacted, it will be more costly and burdensome to implement these requirements at each existing well site because older, existing sites would require far more equipment upgrades, retrofitting, and other operational changes. The commenter contends that these older sites were not designed with these sorts of requirements in mind. The commenter estimates that changes needed to comply with the proposed EG OOOOc will be a substantial economic burden on older wells that have limited production to offset the cost of compliance, which will force operators to prematurely shut in such wells.

Commenter (2252-PAW) asserts that EPA misinterprets its authority under Section 111 of the CAA. The commenter notes that the EPA is charged with determining appropriate emission controls for new facilities while incorporating consideration of the cost of those controls and the correlating emission reductions. For existing facilities, the EPA's two responsibilities are to

establish a procedure by which states are to submit a plan which details the emission controls it intends to require; and reviewing state compliance plans to ensure they are “satisfactory”. Instead, the commenter contends that EPA is proposing comprehensive and expensive emissions controls and leak detection requirements for oil and gas facilities.

Response II-20-15: As discussed in section VIII.B (How does EPA evaluate control costs in this final action?) of the final rule preamble, the final standards will impose some new costs on industry. Many of the standards, however, reflect control mechanisms and measures that many companies and sources around the country are already implementing — again, without deleterious effect on industry as a whole — which shows not only that such controls are “adequately demonstrated” but also underscores their reasonableness from a cost perspective. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in the November 2021 Proposal and the December 2022 Supplemental Proposal, as well as in section XI of this preamble and associated TSDs.

In response to commenters that express concerns related to many of the new requirements under EG OOOOc, reflecting many of the requirements under NSPS OOOOb, where that is the case, it is because BSER was the same, considering any potential retrofit costs.

For EPA’s response to comments on impacts to small businesses, see responses to comments in section 20.3.5 (Small Business Considerations) of this Chapter.

In support of EPA’s use of a “static” natural gas price at \$3.13 (\$/1000 ft<sup>3</sup>) (the average price for 2022) in analyses, while the natural gas price may be volatile, from a long-term perspective, this estimate was and is reasonable to use in analyses. It is important to note, however, that while the \$3.13 (\$/1000 ft<sup>3</sup>) was used in differing BSER analyses to represent the price of natural gas when calculating the natural gas cost savings that would be associated with various regulatory options, the calculated gas savings estimates illustrate the benefits of varying regulatory options being considered but are not used as a sole determinant of what constitutes BSER. Notably, this offset does not apply where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (e.g., transmission stations and storage facilities). Commenter (2220-WDEQ) is correct that NSPS OOOOb (and EG OOOOc) include requirements for a number of different types of affected/designated facilities that could be present at oil and natural gas sites. However, not all sites will have every type of affected facility/designated facility that would be subject to requirements under the final rule. Nonetheless, the EPA considered this comment and other similar comments concerned about the compliance costs when developing the final requirements under NSPS OOOOb and EG OOOOc.

Also, as discussed in Response II-20-25 of this Chapter, the EPA includes key areas where options were chosen to reduce regulatory burden. For example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In other instances, several compliance options are provided to owners and operators based on specific concerns raised by commenters. In addition to providing several compliance alternatives for affected facilities under NSPS OOOOb and designated facilities under EG OOOOc, the EPA has also

considered issues such as lingering supply chain issues and increased demand for equipment and services when establishing compliance, and repair and delay of repair provisions included in the final NSPS OOOOb and EG OOOOc rules to account for parts not being available.

For the NSPS OOOOb, the EPA has concluded that only sources constructed, modified, or reconstructed after the date of the Supplemental Proposal (December 6, 2022) should be considered new sources for the purposes of NSPS OOOOb. Changing this date to December 6, 2022, from the November 15, 2021, reduces the number of existing new sources that will need to comply with NSPS OOOOb, thereby allowing more time to plan for compliance. For details, please see discussion in section IX (Interaction of the Rules and Response to Significant Comments Thereon), subsection A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the final rule preamble. The EPA has also provided an alternative compliance timeline in the NSPS OOOOb final rule for process controllers and pumps required to meet a zero-emission standard (i.e., final rule allows up to one year from the publication date of the final rule). See section XI.D.4 (Compliance dates) of the final rule preamble for a discussion on the compliance dates finalized for process controllers (which also applies for pumps).

For the EG OOOOc, the EPA is finalizing a compliance timeline of 36 months from the deadline for state plan submittals, which provides owners and operators of designated facilities time to plan and meet any increased labor demands. When the compliance timeline of 36 months is considered in conjunction with the state plan submittal deadline of 24 months, that means that sources could have up to 5 years between when the EG are final and when they are required to fully comply with the applicable standards of performance. The EPA believes that this provides the regulated industry sufficient time to plan and comply with the EG. See section XIII.E.3 (Compliance timelines) of the final rule preamble for EPA's response to comments regarding the compliance timeline required under the EG.

Additionally, both NSPS OOOOb and EG OOOOc include provisions that could be pursued for an alternative but equivalent compliance option under NSPS OOOOb or equivalent or less stringent requirements considering remaining useful life and other factors (RULOF) under EG OOOOc under a state plan. 40 CFR 60.5399b (What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?) of NSPS OOOOb provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. See section XIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for state plan requirements and sub-section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

Regarding statements by commenter (2254-PBPA) that the EPA underestimated the reporting and recordkeeping, the EPA notes that the Information Collection Request (ICR) and supporting

statements for the November 2021 Proposed Rule and the December 2022 Supplemental Proposal included detailed estimates of the time and resources necessary for compliance. The commenter did not provide any specific comments on that analysis [or offer any information that might change the analysis]. These impacts are also contained in the ICR and supporting statements for the December 2022 Supplemental Proposal and the final rule. Regarding EPA's estimated reporting and recordkeeping burden for the December 2022 Supplemental Proposal, see the ICR Supporting Statements located at Document ID Item Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO and NSPS OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc), for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. Updated ICR Supporting Statements for this final action are also located in Docket ID No. EPA-HQ-OAR-2021-0317.

### ***20.1.2 Office of Management and Budget (OMB) Circular A-4 (Subject: Regulatory Analysis)***

Comment: Commenter (2220-WDEQ) states that in the RIA for the supplemental proposal, EPA relies on flawed SCM metrics. The commenter encourages EPA to consider the abundant information and analyses that explain why the assumptions made by EPA's Integrated Assessment Models (IAMs) are inaccurate.

In particular, the commenter (2220-WDEQ) directs EPA to, and incorporates herein, a pair of comment letters authored on the "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990." These letters were submitted by Wyoming Governor Mark Gordon and Missouri Attorney General Eric Schmitt (undersigned by Attorneys General of 18 States, including Wyoming), and point out the flawed nature of these metrics.<sup>49,50</sup> As noted in Governor Gordon's letter, the commenter states that the discount rate and the equity weights used to aggregate monetized impacts cause immense uncertainty; the discount rates are extremely low, placing disproportionate weight on future impacts of methane emissions, while devaluing the economic and social benefit created from present-day processes that emit greenhouse gases. The Attorneys General reinforced this point in their comments; the section titled, "The Current Social Costs of Greenhouse Gases Are Deeply Flawed and Cannot Be Fixed by Making More Wild Guesses," explains:

- IAM-based damages analyses are arbitrary
- Calculating global damages is inappropriate
- (The assumptions use) an improper time horizon
- (The assumptions) fail to include 7% discount rate baseline
- The 2021 TSD improperly relies on outdated science

The commenter (2220-WDEQ) adds that the methodologies and metrics used in EPA's calculations have been repeatedly called into question. As the Attorneys General note in their

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<sup>49</sup> Comment Letter on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990," Wyoming Governor Mark Gordon, submitted June 21, 2021, to the Office of Information and Regulatory Affairs of the Office of Management and Budget.

<sup>50</sup> Comment Letter on "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990," Attorney General of Missouri Eric Schmitt and Attorneys General of 18 other undersigned States, submitted June 21, 2021, to the Office of Management and Budget.

comments, “MIT economist Robert Pindyck has found: *an IAM-based analysis suggests a level of knowledge and precision that is nonexistent and allows the modeler to obtain almost any desired result because key inputs can be chosen arbitrarily.*”<sup>51</sup> There is an abundance of supplemental evidence outlining the inaccuracy of IAM-based analyses and the modeled assumptions used to calculate the societal value of reducing emissions of methane....

...EPA’s flawed methodologies for calculating the social cost of methane in the supplemental proposal dramatically overstate societal benefits while significantly underestimating the costs to states and regulated entities to implement the rule. EPA should start over-using a realistic predictor of the actual costs and benefits. When it does, the commenter states that it is confident that the costs of the supplemental proposal will substantially outweigh its benefits.

Response II-20-16: EPA has incorporated recent advancements in the climate science and economics peer-reviewed literature using a modular approach to SC-GHG estimation in the *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Responses regarding the time horizon, global focus, and discounting approach used in the SC-GHG estimates applied in the Final RIA can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA’s September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

The Final Report on the Social Cost of Greenhouse Gases, which is included as Supplementary Material to the Final RIA, discusses the use of Integrated Assessment Models (IAMs) in SC-GHG estimation, and the modular approach adopted in the SC-GHG estimates used in the Final RIA for this action. Regarding the comments about Pindyck (2013)<sup>52</sup>, EPA notes that an article in the peer-reviewed literature, Weyant (2014)<sup>53</sup> addressed this issue as follows:

“While Pindyck’s observations about the empirical weaknesses of IAMs or calculations of the SCC are worthy of careful study, the conclusion that IAMs are therefore useless fundamentally misconceives the enterprise. IAMs and the SCC are conceptual frameworks for dealing with highly complex, non-linear, dynamic, and uncertain systems. The human mind is incapable of solving all the equations simultaneously, and modeling allows making “If... then...” analyses of the impacts of different factors. The models have provided important insights into many aspects of climate-change policy.”

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<sup>51</sup> Robert S. Pindyck, *Climate Change Policy: What do the Models Tell Us?*, National Bureau of Economic Research Working Paper 19244, at 16 (2013).

<sup>52</sup> Robert S. Pindyck, *Climate Change Policy: What do the Models Tell Us?*, National Bureau of Economic Research Working Paper 19244, at 16 (2013).

<sup>53</sup> Weyant, J., 2014. Integrated assessment of climate change: state of the literature. *Journal of Benefit-Cost Analysis*, 5(3), pp.377-409.

Furthermore, Pindyck has consistently noted that modeling and damage category considerations are not a reason to abandon the social cost of greenhouse gases; Pindyck has consistently supported updating the IWG's past estimates (Pindyck 2013<sup>54</sup>, 2017<sup>55</sup>, 2019<sup>56</sup>, 2021<sup>57</sup>).

Comment: Commenter (2344-IER) argues that EPA continues to ignore Circular A-4 (2003) and the requirement of a 7 percent discount rate. The commenter states that, instead of following Circular A-4 (2003), as regulatory agencies have done for twenty years, EPA now wishes to arbitrarily disregard the principles and regulatory analysis established in that document. They add that they believe that this is inappropriate as well as arbitrary and capricious. The commenter provides that, to justify not including a 7 percent discount rate, EPA states:

OMB Circular A-4 (2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG's 2015 Response to Comments, OMB—as a co-chair of the IWG—made clear that “Circular A-4 (2003) is a living document,” that “the use of 7 percent is not considered appropriate for intergenerational discounting,” and that “[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 (2003) itself.”<sup>58</sup>

The commenter (2344-IER) notes that the EPA's description here is intentionally misleading and wrong. Circular A-4 (2003) has a section on intergenerational discounting. It specifically contemplates the ethical issues with intergenerational discounting. For example, Circular A-4 (2003) states:

Some believe, however, that it is ethically impermissible to discount the utility of future generations. That is, government should treat all generations equally. Even under this approach, it would still be correct to discount future costs and consumption benefits generally (perhaps at a lower rate than for intragenerational analysis), due to the expectation that future generations will be wealthier and thus will value a marginal dollar of benefits or costs by less than those alive today. Therefore, it is appropriate to discount future benefits and costs relative to current benefits and costs, even if the welfare of future generations is not being discounted. Estimates of the appropriate discount rate appropriate in this case, from the 1990s, ranged from 1 to 3 percent per annum.<sup>59</sup>

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<sup>54</sup> Pindyck, R.S., 2013. Climate change policy: what do the models tell us?. *Journal of Economic Literature*, 51(3), pp.860-72.

<sup>55</sup> Pindyck, R.S., 2017. Comments on Proposed Rule and Regulatory Impact Analysis on the Delay and Suspension of Certain Requirements for Waster Prevention and Resource Conservation. Comment submitted on Nov. 6, 2017. [https://downloads.regulations.gov/EPA-HQ-OAR-2018-0283-6184/attachment\\_6.pdf](https://downloads.regulations.gov/EPA-HQ-OAR-2018-0283-6184/attachment_6.pdf).

<sup>56</sup> Pindyck, R.S., 2019. The social cost of carbon revisited. *Journal of Environmental Economics and Management*, 94, pp.140-160.

<sup>57</sup> Pindyck, R.S. 2021. Comments on “Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990”. Comment submitted on June 15, 2021. [https://downloads.regulations.gov/OMB-2021-0006-0012/attachment\\_1.pdf](https://downloads.regulations.gov/OMB-2021-0006-0012/attachment_1.pdf).

<sup>58</sup> Environmental Protection Agency, Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, Sept. 2022, p. 7, [https://www.epa.gov/system/files/documents/2022-11/epa\\_scghg\\_report\\_draft\\_0.pdf](https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf).

<sup>59</sup> OMB, Circular A-4 (2003), at 35-36.

After explaining this, as well as the difficulty of determining discount rates for longer time horizons, the commenter (2344-IER) provides that Circular A-4 (2003) states, “If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent.”<sup>60</sup> In other words, under Circular A-4 (2003), EPA may include lower discount rates in its analysis and EPA may include a sensitivity analysis, however, this should be “in addition to calculating net benefits using discount rates of 3 and 7 percent.”

The commenter (2344-IER) contends that the EPA’s continued mischaracterization of the requirements of Circular A-4 (2003) is concerning. Circular A-4 (2003) specifically contemplates and allows other discount rates in addition to 3 and 7 percent. The commenter states that it is unclear why EPA would continually choose to willfully ignore and mischaracterize the requirements of Circular A-4 (2003) other than to obfuscate the impacts of proposed regulation to the American people and the courts. The commenter adds that this is especially true because there is value in providing additional information. As Nobel prize winner William Nordhaus explained:

There are many perspectives through which to view the future costs and benefits of policies to slow global warming. These perspectives differ in terms of normative assumptions, national interests, estimated behavioral structures, scientific data and modeling, risk aversion, and the prospects of future learning. No sensible policymaker would base the globe’s future on a single model, a single set of computer runs, or a single national or ethical perspective. Sensible decision making requires a robust set of alternative scenarios and sensitivity analyses to determine whether some rabbit has in the dead of night jumped into the hat and is responsible for unusual results.<sup>61</sup>

The commenter (2344-IER) asserts that, to have a robust set of alternative scenarios, EPA has to include a scenario with a 7 percent discount rate.

Response II-20-17: A detailed response regarding the omission of SC-GHG estimates using the 7% discount rate can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA’s September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

In addition, EPA notes that the RIA provides estimates for the costs and non-GHG benefits at 2%, 3%, and 7% discount rates.

Comment: Commenter (2359-CEI) suggests that the EPA defends the Obama and Biden administrations’ practice of comparing domestic regulatory costs to global climate benefits, noting, for example, that international trade, investment, and tourism create “spillover pathways” that make other nations’ problems our problems as well.<sup>62</sup> Whatever the merits of that argument, the commenter states that it does not alter the fact that Americans bear most of the costs of

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<sup>60</sup> OMB, Circular A-4 (2003), at 36.

<sup>61</sup> William D. Nordhaus, A Review of the Stern Review on the Economics of Climate Change, 45 J. of Econ. Lit. 686, at 701, Sept. 2007.

<sup>62</sup> RIA, p. 3-9.

regulations on the U.S. gas industry while non-Americans reap most of the purported climate benefits asserted for the proposed rule.

The commenter (2359-CEI) adds that, however valid it may be to present an estimate of global climate benefits, those should be reported separately from estimated domestic benefits, as OMB Circular A-4 (2003) directs.<sup>63</sup> The commenter asserts that there is no scientific or ethical justification for hiding the comparatively smaller domestic benefits of U.S. climate regulations.

Response II-20-18: A detailed response regarding the use of global SC-GHG estimates can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

Comment: Commenter (2343-NYU School of Law) notes that the RIA limits its analysis to impacts that occur between 2023 and 2035.<sup>64</sup> The commenter requests that EPA better explain the justification for and expected implications of the selected time horizon, including whether the agency expects—as is often the case—that significant benefits will accrue beyond 2035.<sup>65</sup> Though EPA concedes that “it would be desirable to analyze impacts beyond 2035,” the commenter states that it concludes that “limited information available to model long-term changes in practices and equipment use in the oil and natural gas industry make the choice of a longer time horizon infeasible.”<sup>66</sup> It further claims that, “[i]n a dynamic industry like oil and natural gas, technological progress is likely to change control methods to a greater extent over a longer time horizon, creating more uncertainty about impacts of the” proposed standards.<sup>67</sup> The commenter recommends that EPA consider how other agencies have made predictions for the oil and gas industry further into the future.<sup>68</sup>

The commenter (2343-NYU School of Law) provides that, as Circular A-4 (2003) notes, “[t]he time frame for [an agency’s] analysis should cover a period long enough to encompass all the important benefits and costs likely to result from the rule.”<sup>69</sup> Even if predicting the impacts that these proposed standards will have after 2035 is difficult, failing to assess (either quantitatively

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<sup>63</sup> Office of Management and Budget, *Regulatory Impact Analysis: A Primer*, p. 5, [https://www.reginfo.gov/public/jsp/Utilities/circular-a-4\\_regulatory-impact-analysis-a-primer.pdf](https://www.reginfo.gov/public/jsp/Utilities/circular-a-4_regulatory-impact-analysis-a-primer.pdf).

<sup>64</sup> *Id.* at 27.

<sup>65</sup> See LANCE BOWMAN, INST. FOR POL’Y INTEGRITY, ENHANCING CONSIDERATION OF TIME FRAMES IN COST-BENEFIT ANALYSIS 2 (2022). Other agencies have considered the impacts of oil and gas activities for decades into the future. See, e.g., BUREAU OF OCEAN ENERGY MGMT., BOEM 2022-030, 2023–2028 NATIONAL OUTER CONTINENTAL SHELF OIL AND GAS LEASING PROPOSED PROGRAM DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT iii (2022), <https://perma.cc/7PS7-PK9R> [hereinafter BOEM 2022 PEIS] (determining the potential environmental impacts from lease sales held under the 2023–2028 Program, under assumption that the environment may be affected by oil and gas activities during the 40 to 70 years when they may occur).

<sup>66</sup> RIA, *supra* note 3, at 27.

<sup>67</sup> *Id.*

<sup>68</sup> See, e.g., BOEM 2022 PEIS, *supra* note 6, at iii; ENERGY INFO. AGENCY, ANNUAL ENERGY OUTLOOK 2022 WITH PROJECTIONS TO 2050: NARRATIVE 2, 26–36 (2022), <https://perma.cc/D5D7-T4JJ> (modeling the production and consumption of oil and natural gas until 2050 under multiple assumptions and methodologies including consideration of technological changes, laws, and regulations).

<sup>69</sup> Off. of Mgmt. & Budget, Circular A-4, at 15 (2003), <https://perma.cc/X8JM-YZMT> [hereinafter Circular A-4 (2003)].



or qualitatively) any impacts after that time would be tantamount to assuming those impacts would be negligible or zero. According to the commenter, the greater likelihood is that new standards would have long-term effects that—while perhaps difficult to predict with precision—would be nontrivial compared to the baseline. Put differently, EPA’s proposed standards would very likely change the oil and gas sector in ways that would last well beyond 2035 compared to a world in which it changed nothing, even if more precise predictions would be difficult to develop.

Response II-20-19: The EPA extended the analysis horizon beyond 2035 to 2038 but declined to extend the analysis further due to the significant uncertainties in projected long-run sectoral trends; see Section 5.2 in the Final RIA for additional discussion. EPA notes that while EIA has made projections for oil and gas production and consumption beyond 2050, the modeling approaches are far different than those employed by EPA and do not require the detailed representation of emissions needed to assess regulatory impacts. While the EPA does not dispute that the regulation may change the oil and gas sector in ways that extend beyond the analysis horizon of the RIA, it maintains that such impacts are sufficiently speculative that little additional value would be gained by further extending the analysis.

Comment: Commenter (2254-PBPA) notes that the EPA estimated the impacts of changes in GHGs using an updated estimate for SCC and SCM. In 2021, the SCC was \$51/ton and the SCM was \$1,500/ton. As part of this proposal, the EPA has adopted an SCC of \$190/ton and an SCM of \$1,900/ton. The commenter states that, not only does the Proposed Rule include a massive increase in the estimate for the SCC and SCM, but the Proposed Rule incorrectly evaluated global benefits, instead of domestic benefits, and applied the incorrect discount rate.

The commenter (2254-PBPA) states that they know that EPA failed to properly evaluate benefits and used the incorrect discount rate because President George W. Bush’s OMB issued Circular A-4 in 2003 to ensure agencies use a “standardiz[ed]” way of “measur[ing] and report[ing]” the “benefits and costs of Federal regulatory actions.”<sup>70</sup> Circular A-4 (2003) contains two foundational principles: first, agencies are to use a 3 and 7 percent discount rate; second, agencies are to consider domestic—rather than global—costs and benefits.

However, the commenter (2254-PBPA) contends that the EPA ignored these principles and applied multiple discount rates of 2.5, 3, and 5 percent – ultimately 3% was the selected rate. The commenter adds that Circular A-4 (2003) also instructs agencies to make domestic effects the basis of their analysis: “Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.”<sup>71</sup> Yet, the commenter complains that the EPA openly relied on global effects in developing its 2022 SCC and SCM estimates.

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<sup>70</sup> Circular A-4, at 1 (September 17, 2003).

<sup>71</sup> Id. at 15. Courts have recognized this unmistakable direction to focus on domestic, rather than global, effects. See *Wyoming v. United States Dep’t of the Interior*, 2020 WL 7641067, at \*21 (D. Wyo. Oct. 8, 2020) (noting that Circular A-4 (2003) mandates a national focus); *State v. Bureau of Land Mgmt.*, 286 F. Supp. 3d 1054, 1069 (N.D.

The commenter (2254-PBPA) concludes by asserting that the Proposed Rule should not be finalized until EPA revises its analysis to be consistent with Circular A-4 (2003).

Commenter (2237-ICND) states that the EPA's reliance on EO 13990 does not excuse it from its obligations under the CAA to justify the Supplemental Proposal based on national, and not global benefits allegedly associated with the Proposal. OMB Circular A-4 (2003), on which EPA relies, specifically directs EPA to focus its analysis "on benefits and costs that accrue to citizens and residents of the United States." (Circular A-4 (2003) at E.1.) Where an agency chooses to evaluate a regulation that is "likely to have effects beyond the borders of the United States, these effects should be reported separately" (id.). The commenter contends that the EPA has violated the direction of Circular A-4 (2003), explicitly stating that it has not calculated a domestic social cost of GHGs that would allow an "apples-to-apples" evaluation of the domestic costs of the Supplemental Proposal against the domestic benefits.

Conversely, commenter (2208-CCES et al) states that the EPA appropriately accounts for global climate damages in the Draft Update, following the approach consistently applied by the Working Group that EPA first adopted under the George W. Bush administration.<sup>72</sup> Including climate impacts that originate abroad but affect domestic welfare is consistent with Circular A-4 (2003)'s guidance that agency analysis incorporate effects "that accrue to citizens and residents of the United States" and to also report "effects beyond the borders of the United States."<sup>73</sup> The commenter adds that they believe that EPA correctly identifies numerous pathways through which the use of global climate-damage valuations captures critical climate-change impacts that affect the U.S. and its citizens but do not originate within the country's borders. For one, as EPA explains, U.S. economic, national security, public health, and humanitarian concerns are "inextricably linked to the rest of the world" such that climate-change impacts that originate in foreign countries will inevitably spill over into the U.S., affecting global supply chains, migration patterns, and security risks.<sup>74</sup> EPA also recognizes that "climate change will directly impact U.S. interests that are located abroad," highlighting the millions of U.S. citizens living abroad, the more than \$6 trillion in U.S. assets located abroad, the more than 500 U.S. military bases located abroad, and U.S. resources in the global commons such as fisheries.<sup>75</sup>

Response II-20-20: A detailed response regarding the use of global SC-GHG estimates and the omission of SC-GHG estimates using the 7% discount rate can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft*

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Cal. 2018) ("While Plaintiffs argue that the same Circular directs BLM to encompass 'all the important benefits and costs likely to result from the rule,' including 'any important ancillary benefits,' it does not specifically mandate that agencies consider global impacts."). Reflecting this clear directive, "the typical agency practice is, in fact, to leave foreign impacts out of cost-benefit analyses entirely." Arden Rowell, Foreign Impacts and Climate Change, 39 Harv. Envtl. L. Rev. 371, 373 (2015); Smith Decl. 18 ("Circular A-4 (2003) still requires that analysis results be presented for both the 3% and 7% discount rates, and for domestic benefits alone.").

<sup>72</sup> Regulating Greenhouse Gas Emissions Under the Clean Air Act, 73 Fed. Reg. 44,354, 44,446 (July 30, 2008).

<sup>73</sup> *Zero Zone, Inc. v. Dep't of Energy*, 832 F.3d 654 (7<sup>th</sup> Cir. 2016); *California v. Bernhardt*, 472 F. Supp. 3d 573, 611–14 (N.D. Cal. 2020).

<sup>74</sup> Draft Report, *supra* note 2, at 11–13.

<sup>75</sup> Id. At 11.

## **20.2 Impacts to Regulatory Agencies**

Comment: Several commenters (2179-KIOGA, 2220-WDEQ, 2222-WDNR, 2225-WESTAR, 2237-NDIC, 2247-OH EPA, 2288-NDDEQ, 2292-WVAG et al, 2294-OOGA, 2330-KDAQ, 2310-MDEQ, 2322-AR DEQ, 2337-KDHE, 2393-OSEE, 2403-PAO, 2418-SDDANR) express concern that the proposed rule imposes a significant burden on state resources. Many of the commenters are specifically concerned with the impacts anticipated due to the EG implementation workload requirements. Commenters contend that the burden may impact implementation. Several commenters request that EPA provide additional funding to states, tribes and local air agencies to plan for and implement the proposed rules. Examples of some of the comments provided are presented in the following paragraphs.

Commenter (2222-WDNR) expresses concern with the significant workload required to identify existing facilities affected by the EG due to EPA failing to provide a list of affected facilities.

Commenter (2247-OH EPA) expresses concern about the amount of work associated with the EGs because of the large number of wells in existence. The commenter requests that EPA provide adequate time. The commenter reports that according to Ohio's Department of Natural Resources, Ohio currently has more than 53,000 operating oil & gas wells. The commenter states that currently, Ohio EPA regulates only a subset of these wells – only the horizontally fracked wells that have been installed since in 2011. This amounts to about 725 well sites. The commenter states that these wells are currently regulated under the General Permit (GP) program where each well site gets issued a permit with standard terms and conditions. The commenter notes that upon the adoption of revised rules to take into account EPA's proposal, the state will need to update the General Permits. The commenter reports that this will be a resource intensive process. The commenter adds that there are 52,250 unregulated wells. The commenter states that Ohio has not regulated these wells because the level of VOC emitted from each well were minor. However, under these proposed rules, the commenter notes that Ohio will need to regulate substantially more wells.

Commenter (2403-PAO) expresses concern with EPA unnecessarily burdening state delegated agencies with excessive requirements if they don't adhere to the Proposed Rule's presumptive standards for existing sources. Commenter (2322-AR DEQ) expresses concern that the EPA's Proposed Rule contains requirements for entities spanning the entire range of production volume, from the largest producing well-pads to single well-heads that are purely domestic in nature and used for home heating. The commenter reports that their agency currently permits approximately 200 facilities in the oil and natural gas sector through its Office of Air Quality. The Arkansas Department of Energy and Environment's Oil and Gas Commission (OGC) currently permits approximately 19,000 oil and gas wells, 1700 tank batteries, and 5000 miles of natural gas pipeline and other potentially affected sites. Under the Proposed Rule, the commenter states that their agency will become responsible for the implementation, development of compliance strategy and determination, and enforcement for over 60,000 sources. The number of sources will likely increase as development continues to meet the energy needs of Arkansas and

surrounding states that gain energy stability from marketable Arkansas products. The commenter asserts that the state simply cannot expand capacity under current constraints to adequately permit and enforce both the delegated NSPS and a state plan for existing sources under the Proposed Rule.

Commenter (2294-OOGA) notes that the Ohio EPA will be responsible for the permitting, compliance/enforcement actions, and other planning efforts for the 62,000 oil and natural gas wells in Ohio. The costs and resources (e.g., administrative staff, office space, and training) necessary significantly exceed Ohio EPA's current budget and personnel. Add the 2-year compliance timeframe, and a herculean order becomes an almost certain impossibility.

Similarly, commenter (2393-OSEE) is concerned about the significant cost of the implementation of a compliance and enforcement program for such a massive amount of facilities. Without additional funding from EPA, the commenter states that resources will be stretched very thin. The commenter believes that this could create an environment where some companies try to take advantage of these limitations and make no good faith effort to comply with EG OOOOc. The commenter notes that companies that do comply are placed at an economic disadvantage, thus creating an unlevel playing field.

Commenter (2418-SDDANR) disagrees with EPA's assertion that the proposal does not meet the requirement for an unfunded mandate because the estimated costs are less than \$100 million. The proposed EG will require the implementation of the proposed rulemaking, inform the affected sources, and perform compliance activities on those sources. The commenter estimates that there are hundreds of sources in South Dakota that are not currently affected by air permitting that could be subject to the proposed emission guidelines. South Dakota's federal funding received to implement its existing programs has been stagnant for over 20 years. The commenter asserts that EPA continues to ask states to do more with its existing resources without additional funding.

Commenter (2225-WESTAR) notes that states acknowledge that this ambitious agenda, coupled with implementing programs under the Inflation Reduction Act (IRA), will be demanding, especially given understaffing issues at both the federal and state levels. Not having a clear picture of funding mechanisms, whether it's potential IRA funding or other funding streams, means states, tribes, and local air agencies cannot clearly plan for what it may take to implement all requirements under the proposed rule. The commenter asserts that the cost burden for agencies with large numbers of oil and gas facilities is not insignificant, and with no additional funding to air agencies identified, state, tribal, and local air agency programs will be strained.

Commenter (2292-WVAG et al) provides that West Virginia's environmental regulatory agency noted that implementing EPA's timetable of existing source monitoring in West Virginia alone could cost over \$278 million each year.<sup>76</sup> The commenter asserts that these costs will increase due to the extra requirements of the December 2022 supplemental proposal. For example, the states' implementation plans will add significant compliance costs because the states must follow

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<sup>76</sup> See W. Va. Dep't of Env't Prot., Comment Letter on Proposed Rule Establishing New Standards of Performance for New and Modified Sources of Methane In the Oil and Natural Gas Sector 2 (Jan. 14, 2022), <http://bit.ly/3HQDjdU>.

various new calculation and monitoring requirements to invoke remaining useful life, and community outreach.

Commenter (2179-KIOGA) asserts that the proposed rule imposes a burden and insurmountable costs for the state. The commenter notes that there are over 62,000 oil wells and over 20,000 natural gas wells in Kansas. Other comparable states estimated costs to develop and implement this proposed rulemaking to be over \$40 million annually. Furthermore, the commenter asserts that these states estimate the cost on the proposed timing (final compliance within 2 years) is even more outrageous at over \$278 million annually. The estimate includes 2,708 additional full time equivalent persons to be hired. Kansas would incur similar costs.

Commenter (2220-WDEQ) believes that EPA did not realistically evaluate impacts to states and notes that EPA has not provided funding to states. The commenter notes that as a nationally prominent producer of oil and natural gas, Wyoming will bear a disproportionate burden to implement this rule compared to many other affected states. As of October 2022, Wyoming ranked eighth nationally in oil production<sup>77</sup> and for the 2021 calendar year, Wyoming ranked ninth in marketed production of natural gas.<sup>78</sup> Furthermore, the commenter notes that Wyoming has 16 of the nation's 100 largest natural gas fields, including the Pinedale and Jonah fields, which rank among the top 10.<sup>79</sup> According to the Wyoming State Geological Survey, Wyoming operators were on track to produce about 90 million barrels of oil in 2022.<sup>80</sup> The commenter states that because of the state's CAA primacy programs and other regulatory authority over Wyoming's extensive oil and gas industry, all areas in the state are meeting ambient air quality standards. The commenter notes that state programs cover over 18,000 operating single well sites and compressor stations. The number of these sites alone is significant, but it pales in comparison to the increase in specific equipment that would be subject to the proposed rule such as pneumatic pumps and controllers.

As such, the commenter (2220-WDEQ) contends that the supplemental proposal imposes compliance assurance costs on Wyoming without providing the funding to meet these additional federal regulatory burdens. For more than a decade, the commenter notes that federal funds have only provided about 7 percent of the state's budget, with the rest coming from operator-paid fees or the State's General Fund. With the additional costs that will be imposed on Wyoming to implement the supplemental proposal, the proportion of federal funds will be further decreased, and the burden shifted to Wyoming's citizens and industry to shoulder the difference.

The commenter (2220-WDEQ) asserts that those costs are of a magnitude that is simply unworkable for the state (and likely other state regulatory agencies) with no significant environmental outcomes. The proposed requirements pertaining to fugitive emissions monitoring and repair programs, including monitoring for fugitive emissions with optimal gas imaging (OGI), impose a massive reciprocal workload for state agencies. Conducting the compliance

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<sup>77</sup> U.S. Energy Information Administration, <https://www.eia.gov/state/rankings/#/series/46>.

<sup>78</sup> U.S. Energy Information Administration, <https://www.eia.gov/state/rankings/#/series/47>.

<sup>79</sup> U.S. Energy Information Administration, Wyoming State Profile and Energy Estimates, <https://www.eia.gov/state/analysis.php?sid=WY>.

<sup>80</sup> Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, "Oil & Natural Gas Resources in Wyoming," January 2023 Summary Report.

inspections, reports, and emissions inventories work commensurate with the requirements of the supplemental proposal places an overwhelming strain on agency staff and financial resources. The enormous increase in workload would require hiring additional full-time employees (FTE), as well as training costs, equipment costs, and other associated costs. But the proposed rule does not fairly take these costs into consideration.

The commenter (2220-WDEQ) notes that the EPA projects that the number of incrementally impacted facilities will increase immensely between 2025 and 2026. For example, EPA notes that affected well site fugitives will jump from 31,000 to 520,000 between those two years (increasing by 16.77 times). Affected transmission and storage compressor stations will jump from 0 to 1,900. Applicable pneumatic devices will jump from 167,600 to 1,400,000 (increasing by 8.35 times), affected liquids unloading operations will jump from 15,000 to 260,000 (increasing by 17.33 times). The commenter asserts that it is not possible to definitively assess the scope of impacts upon facilities in Wyoming because there are not defined requirements included in the proposed rule. However, if the commenter applies a rough estimate of an incremental jump of roughly ten times, or even five times, for its statewide affected facility impacts, the associated costs to the agency would be immense.

The commenter (2220-WDEQ) reports that currently, state staff complete about 1,000 Full Compliance Evaluations (FCEs) on oil and gas sites annually, with an additional 1,500 site visits or Partial Compliance Evaluations (PCEs). The staff also reviews more than 26,000 reports annually. The commenter provides that State compliance staff that undertakes this work includes 22 positions that span from entry-level engineers to senior-level engineers, with an annual salary and fringe benefit cost to the agency of nearly \$3 million.<sup>81</sup> Given the tight window for reviewing the massive scope of the proposed rule, it is difficult for the commenter to provide a precise estimate of the number of additional reports that will need to be undertaken, the amount of additional time needed to conduct an FCE as a result of the added inspection requirements, and the increased number of FCEs, PCEs, and site visits that will be necessary. However, given the estimated incremental jump of statewide affected facilities, the commenter notes it is beyond dispute that the supplemental proposal will have a massive impact upon the workload of the State's compliance program – and, given the number of existing FTE, would have a severe impact upon the number of other inspections that could be completed annually.

Furthermore, the commenter (2220-WDEQ) asserts that the proposed specifications in Appendix K relating to such things as the required performance of qualifying infrared cameras and required training and verification, impose significant additional costs to the agency. The commenter estimates that initial training costs alone to certify staff in operating OGI cameras would initially be roughly \$80,000 to \$100,000. The cost of purchasing and regularly maintaining necessary OGI equipment to comply with the requirements is estimated at \$1.3 million. There are also additional concerns regarding the 1,400 survey hour requirement (including 40 hours in the past 12 months) necessary to qualify senior OGI camera operators in Appendix K, as well as the initial field training requirements for other operators. The commenter has concerns regarding the qualified personnel requirements for conducting the necessary inspections; given the more restrictive parameters. The commenter states that it would have to redirect staff resources to meet these requirements, which would inhibit the agency's ability to meet other compliance

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<sup>81</sup> Cost statistics regarding FTE/Additional FTE provided by WDEQ's Administration Division.

obligations. Moreover, they state that there would likely be higher travel costs to the agency given the significant increase in site visits.

The commenter (2220-WDEQ) provides that it is impossible to provide specific costs to the agency to fulfill the compliance demands of the supplemental proposal in the condensed timeframe allocated by EPA for submitting comments. However, given the incremental jump in affected facilities, a general idea of some of the inspection requirements, and associated training costs, equipment costs, travel costs, and other costs, it is reasonable to assume the agency would have to hire significantly more staff. The commenter provides that the associated cost of hiring even five additional compliance staff (one of whom would be at a senior level) would cost the agency \$670,000 annually. These estimates, coupled with the costs identified above, would impose an immediate financial burden on the agency of about \$2.1 million, which does not account for recurring annual employee costs, recurring equipment maintenance and update costs, recurring future travel costs, office space and equipment costs, etc. The commenter asserts that the supplemental proposal also will likely require hiring additional full time equivalent (FTE) support (or contractor support) for completing the state plan requirements and other implementation provisions. Adding three FTE under their State Implementation Plan & Rule Development section would result in an additional \$390,000 annual burden, bringing the annual salary and fringe benefit burden associated with the supplemental proposal to \$1,060,000 for eight additional positions. In total, they report that the immediate financial burden on the agency would be nearly \$3 million, which is more than a 10 percent increase in the State agency's current total budget.<sup>82</sup>

Commenter (2220-WDEQ) states that the RIA does not represent the potential costs that state-level regulatory agencies will have to bear to meet the implementation requirements of the supplemental proposal. The commenter notes that the RIA only represents the projected compliance costs and projected regulatory costs as applied to the oil and natural gas markets. The commenter explains that State agencies will incur significant costs to meet the compliance requirements, reporting and recordkeeping requirements, requirements for developing State Plans, and conducting the consequential meaningful engagement required in the supplemental proposal. In order for the commenter (representing the Wyoming Department of Environmental Quality) to effectively address the immense increase in workload associated with the supplemental proposal, additional staff would need to be added to its programs for Compliance, State Implementation Planning and Rule Development, and potentially other areas. Based on February 2023 cost estimates, the commenter anticipates an immediate financial burden to the agency of nearly \$3 million (which includes a one-time cost for purchasing and maintaining technical equipment and training staff to meet the requirements of the supplemental proposal, as well as an annual cost for employing, at a minimum, eight additional staff to perform the activities associated with the supplemental proposal).<sup>83</sup> The commenter provides a full breakdown of the resulting costs to their agency from the supplemental proposal in Section 5 and Section 8 of their comments.

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<sup>82</sup> Cost statistics regarding FTE/additional FTE provided by WDEQ's Administration Division; cost-estimates regarding compliance duties associated with the proposed rule provided by AQD's Compliance Program.

<sup>83</sup> Cost statistics regarding FTE/Additional FTE provided by WDEQ's Administration Division; cost-estimates regarding compliance duties associated with the supplemental proposal provided by AQD's Compliance Program.

The commenter (2220-WDEQ) notes that the EPA attempts to address the cost burden associated with the supplemental proposal on pages 74844-74845 of the preamble (D. Unfunded Mandates Reform Act (UMRA)). The commenter provides that the EPA considers the EG-associated costs as a result of NSPS OOOOc as follows:

The EPA is proposed under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the requirement for states to develop state plans. As explained in section XIV.G. of the November 2021 proposal and section V of this supplemental proposal, the EG also does not impose specific requirements on tribal governments that have designated facilities located in their area of Indian country. The burden for states to develop state plans following promulgation of the rule is estimated to be below \$100 million in any one year. Thus, the EG is not subject to the requirements of section 203 or section 205 of the UMRA.

The commenter (2220-WDEQ) recommends that the EPA recognize that even though a rulemaking is projected by EPA to fall below the \$100 million economic impact, there may nevertheless be a significant fiscal impact on a state's economy and/or on a state's regulatory program. State economies vary in size and certain industries have varying degrees of influence on state economies. Furthermore, the commenter explains that state implementing agencies vary across the country in size and available funding; not all states have the same resources or staffing available for implementing a plan that dramatically increases the demand on existing resources to regulate the universe of affected sources in that state. The costs to state agencies not only include the development of state plans, as cited by EPA in its cost-burden analysis, but also includes the implementation of those plans. The commenter adds that this problem is further complicated by the nationwide challenge that both federal and state agencies are experiencing in recruiting and retaining qualified air quality staff. This issue is further exacerbated by the large number of proposed rules that EPA is promulgating and associated unfunded mandates. It is reasonable that EPA considers this in its impacts of the supplemental proposal.

The commenter (2220-WDEQ) suggests that the supplemental proposal has an outsized impact upon states like Wyoming whose economies are resource-dependent. They add that the proposal will have an outsized impact upon agencies like theirs that may have significantly smaller staffing and less funding available compared to other state agencies. A "one-size-fits-all" approach to the benefits and costs associated with implementing a rulemaking does not reflect how a rulemaking may affect certain states differently than others. The commenter states that the fact that EPA did not provide specific figures in the RIA for the costs to state-level agencies to implement the supplemental proposal is problematic and lacks transparency. Furthermore, they add that the cumulative cost totals for implementing the supplemental proposal nationally do not show the disproportionate manner in which certain agencies like theirs are more heavily burdened than other states. The commenter contends that it is crucial that EPA takes this into consideration when promulgating a final rule and that the federal government provides states with the funding for staffing and resources necessary for implementation of state plans.

Commenter (2310-MDEQ) requests commensurate funding to develop and implement the proposed rule. The commenter asserts that the current rate of regulatory activity proposed by EPA is unprecedented, while long term funding to states has remained flat. The commenter notes



that states are struggling with financial resources needed to adequately staff the increase in workload. The commenter adds that not only are states struggling to retain and recruit staff, but regional EPA offices are also operating with fewer staff. Rather than adding more burden to a stressed system, the commenter believes that this is EPA's opportunity to develop appropriate timelines and ensure adequate funding to their co-regulators, the states, to ensure their goals of increased environmental protection can be met.

Commenter (2337-KDHE) reports that the proposed EGs would impose a burden and insurmountable costs for Kansas. The commenter contends that the proposed rule is flawed since it pertains to state implementation of the EGs but ignores the costs to the states to implement the EGs for existing sources. The commenter reports that there are approximately 78,000 active oil wells and 28,000 active natural gas (including coalbed methane (CBM)) wells<sup>84</sup> within the state.

Although the commenter (2337-KDHE) has not done an in-depth cost analysis at this time, an estimate regarding the potential impact on the state to develop and implement the proposed rule (without any additional sources or activities where EPA solicited comment), based on approximately 106,000 permitting actions, compliance efforts, and other planning related activities to develop a state rule and State Plan in accordance with the proposal, would be enormous. The commenter reports that 93 of the 105 counties in Kansas have oil and gas well activity.

The commenter (2337-KDHE) notes that in the preamble, EPA states their commitment to providing "aid and guidance" to states. The commenter contends that "aid and guidance" are not an acceptable substitute for adequate funding needed for this proposed federal initiative being imposed upon the state. The commenter notes that EPA does not include costs for the states to comply with the EGs. The commenter asserts that states, not affected facilities, are subject to the EGs; therefore, this proposed rule is flawed since it pertains to state implementation of the EGs but ignores the costs to the states to implement the EGs for existing sources.

Commenters (2288-NDDEQ, 2237-NDIC) separate funding comments into two categories: initial funding for the development of a state plan implementing EG OOOOc and initial funding for implementation of NSPS OOOOb requirements, and ongoing funding to assist with ensuring continued compliance with both the state plan and NSPS OOOOb.

First, the commenters (2288-NDDEQ, 2237-NDIC) express concern regarding the apparent lack of resources provided for the development of a state plan addressing designated facilities in the oil and gas sector. The commenters are unaware of any additional federal funding being allocated to already resource constrained state budgets. The commenters request that EPA explain how states are to successfully take on this additional regulatory burden without adequate funding.

Second, the commenters (2288-NDDEQ, 2237-NDIC) note that in addition to submitting these comments, it is evaluating the revised proposal for its full impact upon sources within the state. Even so, the evaluation so far has revealed an expansive list of requirements for owners and operators that the commenter will have to review and investigate to determine how best to implement compliance actions. Unlike EPA, the commenters strongly believe that it is critical to

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<sup>84</sup> According to the table at <https://www.kgs.ku.edu/PRS/countyStats.html>.

conduct a combination of compliance oversight including field inspections, onsite record reviews, and company audits, in addition to EPA's preferred approach or report review only. The commenters state that regulation without active and collaborative oversight is meaningless and burdensome. However, all this effort takes considerable resources that EPA has so far offered no assistance for. The commenters are concerned with its commitment that "[f]or most designated facilities, the EPA proposes to conclude that compliance with the implementing state or Federal plan that is consistent with the presumptive standards in EG OOOOc would constitute compliance with the older NSPS because the presumptive standards proposed for EG OOOOc result in the same or greater emission reductions than the current standards in the older NSPS." If the EPA goes forward with this commitment, they state that it will require that they devote resources (of which EPA has not provided) towards the implementation of EG OOOOc for previously unregulated sources, but also to devote NSPS KKK, OOOO, and OOOOa resources towards reviewing EG OOOOc documentation to determine if that documentation fulfills the NSPS KKK, OOOO, or OOOOa requirements. According to the commenters, if EPA believes that the proposed EG OOOOc could result in the same emission reductions as current programs, then the proposal for additional regulatory actions are burdensome without environmental benefit. The commenters assert that EPA must show empirical data that the proposed regulations actually improve environmental protection over the existing state/federal regulations and if they do then EPA must provide resources commensurate with the intended regulation. If either of these cannot be accomplished, then the commenters recommend that EPA retract the proposed regulation in its entirety.

Commenter (3845-ND Congress) reports that the EPA's proposed rule will impose additional costs on North Dakota agencies. The commenter notes that NDDEQ required multiple additional full-time employees and millions of dollars in appropriated funds to accept delegation of NSPS OOOOa several years ago. The commenter is worried that the EPA's proposed rule creates new obligations on new sources and would require regulation of existing sources as well. The commenter contends that this goes well beyond the scope of NSPS OOOOa and will require significantly more resources for NDDEQ to implement. However, the commenter argues that the EPA has provided no additional funding for the state. In fact, the commenter contends that the rule is likely to diminish state funds via reductions in royalties and taxes. The proposed rule's unfunded new mandates will strain the NDDEQ's ability to adequately enforce its existing regulations.

Commenter (2225-WESTAR) notes that EPA has over 100 actions on its Fall 2022 Regulatory Agenda, including major nationwide rules with broad applicability. In October 2022, EPA proposed the Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Reconsideration of Fugitive Emissions Rule and then in December 2022, proposed updated requirements to the Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under the Clean Air Act Section 111(d). Along with the Bureau of Land Management's November 2022 proposed rule for Waste Prevention, Production Subject to Royalties, and Resource Conservation, the intertwined impacts of all these rules feel very uncertain. The commenter reports that Western state, tribal, and local air agencies are concerned about the unknown comprehensive effect of advancing these actions simultaneously.

The commenter (2225-WESTAR) provides that states acknowledge that an ambitious regulatory agenda, coupled with implementing programs under the Inflation Reduction Act (IRA), will be demanding, especially given understaffing issues at both the federal and state levels. The

commenter asserts that not having a clear picture of funding mechanisms, whether it's potential IRA funding or other funding streams, means states, tribes, and local air agencies cannot clearly plan for what it may take to implement all requirements under the proposed rule. The commenter notes that the cost burden for agencies with large numbers of oil and gas facilities is not insignificant, and with no additional funding to air agencies identified, state, tribal, and local air agency programs will certainly be strained. The commenter states that state, tribal, and local air agencies will need additional funding from EPA to successfully plan for and implement the requirements.

Commenter (2330-KDAQ) states that EPA's complicated and piecemeal approach in this proposal has not provided meaningful opportunity to comment on the proposed rulemaking. The commenter is unable to fully evaluate the sources and source inventory under this rulemaking as proposed; however, the commenter has estimated approximately 60,000 sources that may become subject to the requirements in the proposed rule. The commenter estimates that the need to add a minimum of 100 staff to evaluate sources, create agency identification numbers, draft permits, and do inspections and monitor compliance.

The commenter (2330-KDAQ) asserts that the rulemaking potentially affects sources that have never been subject to permitting under the CAA. The commenter expects that many sources are unfamiliar with air quality regulations, and they will need significant technical assistance in all areas of compliance and permitting. For example, continued monitoring until wells are permanently plugged as proposed in this rulemaking could potentially require years and years of monitoring and oversight by state regulatory agencies. The commenter contends that EPA support to state regulatory agencies is needed to provide this additional service.

Response II-20-21: The EPA appreciates regulatory agencies' concerns regarding the impact the final rule would have on state resources. the EPA notes that the Information Collection Request (ICR) and supporting statements for the November 2021 Proposed Rule and the December 2022 Supplemental Proposal included detailed estimates of the time and resources required by state agencies to develop and implement the emission guidelines. While these commenters provided information related to their anticipated burden, they did not provide any specific comments on that analysis [or offer any information that might change the analysis]. These impacts are also contained in the ICR and supporting statements for the December 2022 Supplemental Proposal and the final rule. With regard to EPA's estimated reporting and recordkeeping burden for the December 2022 Supplemental Proposal, see the ICR Supporting Statements located at Document ID Item Nos. EPA-HQ-OAR-2021-0317-0144 (NSPS OOOO and NSPS OOOOa), EPA-HQ-OAR-2021-0317-1556 (NSPS OOOOb), EPA-HQ-OAR-2021-0317-1553 (EG OOOOc), for this action located at Docket ID No. EPA-HQ-OAR-2021-0317. Updated ICR Supporting Statements for this final action are also located in Docket ID No. EPA-HQ-OAR-2021-0317. See also the response II-20-14.

With respect to commenter's (2220-WDEQ) assertion that the RIA does not include state implementation costs for the rule, EPA notes that the costs estimated and presented in the ICRs

are significantly smaller than the estimated compliance costs of the rule, so their inclusion would not meaningfully affect the estimated net benefits of the rule.

As discussed under section XVII.D (Unfunded Mandates Reform Act (UMRA)), the burden for states to develop state plans following promulgation of the rule is estimated to be below \$100 million in any 1 year. See also section VII.B (Paperwork Reduction Act (PRA)) of the final rule preamble for EPA's estimate of the recordkeeping and reporting requirements under NSPS OOOOa, NSPS OOOOb, and EG OOOOc. For EG OOOOc, the annual burden for the states (averaged over the first 3 years following promulgation) is estimated to range from 166,000 to 208,000 hours at a total annual labor cost of between \$21 to \$26 million.

### **20.3 Unfunded Mandates Reform Act (UMRA)**

Comment: Commenter (2219-Wyoming Oil and Gas Conservation Commission (WOGCC)) states that, in consideration of the Unfunded Mandate Reform Act (UMRA), EPA does not evaluate the full impact of the proposed rule on state and local governments. The commenter notes that not only will these governments be required to develop state plans, but also EPA appears to imply that well closure requirements will be implemented on orphaned wells. The commenter believes if that is the case then the states would be required to conduct emissions monitoring and leak repair on orphan wells, supply well closure and financial assurance plans to EPA, and ultimately will be required to plug significant numbers of wells that are orphaned because of this rule. The commenter adds that these government entities will lose royalties and taxes associated with the significant number of wells that would be prematurely shut in and plugged or orphaned because of this rule.

Response II-20-22: With respect to the commenter's claim that a significant number of wells would be prematurely shut in and plugged or orphaned, EPA notes that the commenter did not provide specific data to support this assertion. EPA developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and therefore the impact of lost revenue would be minimal. In addition, to mitigate the impact of orphaned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s).

See also section XVI.D (Unfunded Mandates Reform Act (UMRA)) of the final rule preamble. The EG is promulgated under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the requirement for states to develop state plans.

As explained in section XIV.G of the November 2021 Proposal and section V of the December 2022 Supplemental Proposal,<sup>85</sup> the EG also does not impose specific requirements on tribal governments that have designated facilities located in their area of Indian country. The burden for states to develop state plans following promulgation of the rule is estimated to be below \$100 million in any 1 year. Thus, the EG is not subject to the requirements of section 203 or section 205 of the UMRA.

## **20.4 Economic Impacts**

### ***20.4.1 Economic Benefits***

Comment: Several commenters (2331-MHA Nation, 2171-IEEFA, 2209-PLS, 2367-BlueGreen Alliance, 2429-WOC) assert that the proposed rule will result in economic benefits including job security and job creation. Some of the specific comments received are provided below.

Commenter (1609-Qnergy, Inc.) and other U.S. companies are investing significant resources in on-shoring their supply chain to guarantee on-time delivery of methane mitigation products. The commenter already expanded its production capacity by 60% to meet the surging demand with the goal to provide lead time of six weeks or less. The commenter expects that the IRA and other government programs will promote U.S. methane mitigation technologies.

Commenter (2331-MHA Nation) appreciates the proposed rule's economic and environmental benefits. The commenter appreciates that the proposed rules are projected to increase recovery of natural gas. The commenter states that increased gas recovery on the Fort Berthold Reservation would deliver more revenue to fund vital tribal programs.

Commenter (2171-IEEFA) believes that the proposed rules will assist operators in achieving higher future profit margins. The commenter states that the ability of a company to control emissions should yield a commensurate proved reserves benefit. As better usage of LDAR technologies and other solutions required by the EPA are installed, the commenter suspects that a one percent to five percent incremental bump in natural gas production will follow from higher retentions. The commenter states that this production increase will occur with relatively de minimis production and exploration costs, thereby resulting in higher profit margins.

Commenter (2209-PLS) requests that EPA strengthen the proposed rule to mitigate against climate change and protect outdoor recreation. Specifically, the commenter asks that EPA;

- Eliminate routine flaring and ensure that oil and gas operators capture all correlated gas from their operations and strictly limit flaring of methane gas unless necessary for maintenance and safety.
- Apply applicable emission restrictions to storage tanks, which was not included in the November 2021 proposal or the supplemental rule.

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<sup>85</sup> See 86 FR 63256 (November 15, 2021) and 87 FR 74702 (December 6, 2022).

- Expand the Super Emitter Response Program proposal to provide for well-defined guidance and funding to enable broad local community and third-party monitoring for emission compliance.

The commenter (2209-PLS) provides details on the importance of the outdoor recreation economy, and methane pollution's negative impacts. The commenter states that healthy public lands bring quality of life, visitors, and business investment to nearby communities through outdoor recreation. Outdoor recreation businesses rely on access to public mountains, rivers and deserts, and the country has increasingly seen terrible climate change related disasters in recent years. The commenter believes that without strong, common-sense protections against methane and other harmful pollution from oil and gas developments, the \$862 billion<sup>86</sup> outdoor recreation industry will suffer. The commenter notes that climate change uniquely affects outdoor recreation,<sup>87,88</sup> fundamentally changing public land use patterns and stunting economic opportunities. The commenter reports that the evidence<sup>89</sup> of climate change is overwhelming: 16 of the hottest years on record took place between 2000 and 2017, and the 9 most devastating wildfires in American history took place after the year 2000. According to the United Nations' climate science body, methane is responsible for 30 percent<sup>90</sup> of the climate change we are experiencing today, and oil and gas is the largest industrial source of methane pollution, accounting for a third of emissions.

The commenter (2209-PLS) notes that in 2019 Congress held a hearing on the effects of climate change on outdoor recreation, where the Outdoor Alliance testified to the many harms inflicted on the quality of the outdoor recreation experience, health impacts and safety concerns for recreationists, and damage to the outdoor recreation economy.<sup>91</sup> Climate change harms the outdoor recreation industry by causing less snowpack, water insecurity such as low river flows, basic access lost to public lands during fire season (year-round now in some places), and many other detrimental impacts. The commenter notes that the outdoor industry<sup>92</sup> brings millions of jobs to communities across the country in many ways. Recreation visitors bring needed dollars to cities and towns that have recreation assets like rivers, trails, and other outdoor spaces where fishing, hunting, boating, hiking, skiing, biking, climbing, and a long list of other outdoor

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<sup>86</sup> The Bureau of Economic Analysis calculates the economic output of outdoor recreation to be \$862 billion, surpassing industries such as mining, utilities, farming and ranching, and chemical products manufacturing. See <https://recreationroundtable.org/economic-impact/>.

<sup>87</sup> See Climate Change is Changing the Face of Outdoor Recreation, National Recreation and Park Association, found at <https://www.nrpa.org/parks-recreation-magazine/2017/october/climate-change-is-changing-the-face-of-outdoor-recreation/>.

<sup>88</sup> See Outdoor Business Climate Partnership Presents: Climate Advocacy in 2021, Outdoor Industry Association, found at <https://outdoorindustry.org/article/outdoor-business-climate-partnership-presents-climate-advocacy-2021/>.

<sup>89</sup> See How Do We Know Climate Change is Real?, National Aeronautics and Space Administration, found at <https://climate.nasa.gov/evidence/>.

<sup>90</sup> See Methane Rule to Eclipse Past Regulations, Including Obama's, E&E News Climate Wire, found at <https://www.eenews.net/articles/methane-rule-to-eclipse-past-regulations-including-obamas/>.

<sup>91</sup> See testimony re Subcommittee Hearing Examining the Impacts of Climate Change on Public Land Recreation, Outdoor Alliance, found at <https://static1.squarespace.com/static/54aabb14e4b01142027654ee/t/5cddc6fd82a3880001e500c5/1558038270135/OA+Climate+Rec+Impacts+%281%29.pdf>.

<sup>92</sup> See Outdoor Recreation Satellite Account, U.S. and States, 2021, Bureau of Economic Analysis, found at <https://outdoorindustry.org/advocacy/>.

activities take place. Outdoor recreation companies and businesses across a range of industries, both large and small, are choosing to locate in these communities because their employees want to live in places with access to the great outdoors. Across the country, communities that have previously depended primarily upon resource extraction have begun to diversify their economies into the recreation sector. The commenter asserts that promulgating this proposed Methane Rule—along with implementing best practices and using newly developed technologies will protect and improve air quality in oil and gas communities across the country that want to expand regional outdoor recreation economies. The commenter understands the need for energy production, but states that it is time to acknowledge the cost of methane pollution to local communities. Allowing oil and gas operators to use old technology will damage air quality and prohibit communities from diversifying their economies.

Commenter (2367-BlueGreen Alliance) states that jobs in the methane emissions mitigation industry have the potential to provide pathways into the middle class for millions of workers and families, and to support millions of high-skilled, high-wage jobs—particularly in manufacturing. As this sector grows, support is needed to ensure that the jobs created are good-paying, safe, accessible union jobs, especially for those historically underrepresented in these jobs.

The commenter (2367-BlueGreen Alliance) notes a 2021 report from Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry*, further explains existing technologies with a focus on identifying and exhibiting companies that produce the products and services. They found that this sector is growing rapidly. Today there are 33 percent more firms manufacturing methane mitigation technologies than in 2014, and 90 percent more firms providing installation and other services than in 2017:

- At least 215 firms manufacture methane mitigation equipment in the U.S. and/or offer services;
- 70 percent of methane mitigation firms qualify as small businesses;
- Methane mitigation companies provide U.S. jobs in at least 748 locations across 47 states; and
- The methane mitigation industry employs at least 35 key job types<sup>93</sup>

[See Figure B Map of the contiguous U.S. of the commenter’s letter. Figure B Map shows where methane emissions mitigation firms are located.<sup>94</sup>]

The commenter (2367-BlueGreen Alliance) asserts that with full and continuing adoption of 2021 Proposed Rule leak reducing technologies and practices at new and modified oil and gas facilities, this would result in net creation of over 85,000 job-years.<sup>95</sup> While the commenter is currently working on updating their economic modeling to provide a complete picture of the emissions reduction and job creation potential of the EPA’s 2022 Supplemental Proposed Rule,

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<sup>93</sup> Datu Research, *Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry*, 2021. Available online: <https://www.daturesearch.com/wp-content/uploads/Datu-2021-Methane-Emissions-MitigationIndustry.pdf>.

<sup>94</sup> Environmental Defense Fund, *Find Measure Fix: Jobs in the U.S. Methane Emissions Mitigation Industry*, July 2022. Available online: [https://www.edf.org/sites/default/files/us\\_methane\\_mitigation\\_industry\\_report.pdf](https://www.edf.org/sites/default/files/us_methane_mitigation_industry_report.pdf).

<sup>95</sup> Based upon internal BGA research. Note that the jobs estimates reported here are more appropriately called “job-year equivalents.” Each “job” represents an increase in demand for employment sufficient to employ one-person full time for one year.

their preliminary analysis suggests that the 2022 supplemental would amplify the job creation potential of the 2021 proposal by improving emissions monitoring, reducing flaring, and expediting technological deployment. In many ways, the commenter states that job creation from the EPA's proposed standard is supported by the infrastructure investments needed to mitigate methane leaks. The Business Roundtable notes, for example, that over a 20-year period, every additional \$1 invested in infrastructure drives roughly \$3.70 in additional economic activity.<sup>96</sup> Especially when done at scale, they believe that infrastructure investments will drive new employment opportunities. The commenter asserts that the proposed rule will drive infrastructure investment as a critical step to reduce fugitive methane emissions — in this case to reduce such emissions by an estimated 36 million cumulative short tons over the period 2023 through 2035, along with 9.7 million tons of VOCs and 390,000 tons of HAPs.<sup>97</sup>

Based on their modeling of the 2021 Proposed Rule, the commenter (2367-BlueGreen Alliance) asserts that the impacts of this rule will be generally positive. The commenter expects that both the construction and manufacturing sectors will show positive gains in employment as they both produce and install critical upgrades in a variety of oil and gas operations which deliver the estimated emission reductions. This is because the emissions reduction technologies modeled, specifically in leak detection and repair (LDAR), are more labor intensive than the oil and gas extraction industry on average and can produce increased net revenues by reducing waste. As a result, job losses that result from reduction in traditional extraction operations are more than offset by a shift to jobs required to sustain emissions reduction efforts. Many of these new jobs could be filled by workers with skills and experience in the oil and gas industry.

The commenter (2367-BlueGreen Alliance) notes that under the 2022 Supplemental Proposed Rule, EPA has incorporated technological flexibility into the standards to promote innovation, including giving firms the ability to utilize a diverse array of technologies to observe leaks. The commenter contends that in making these modifications, EPA provides full access to the technologies in the burgeoning methane mitigation industry, providing a potential catalyst for further job growth.

The commenter (2367-BlueGreen Alliance) asserts that the new Super Emitter Response Program potentially opens a pathway for groups like labor unions to qualify as third-party monitors, expanding the number of high-quality jobs created by this action.

The commenter (2367-BlueGreen Alliance) states that the need to implement and operate advanced equipment and apply more comprehensive leak detection and mitigation technologies over time suggests jobs directly created in the oil and gas sector would not require relocation—the skilled local workforce will already be in place. While some jobs would engage engineering

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<sup>96</sup> Business Roundtable, Delivering for America: The macroeconomic impacts of reinvesting in America's infrastructure systems, January 2019. Available online: <https://s3.amazonaws.com/brt.org/BRTInfrastructureReport12052018.pdf>.

<sup>97</sup> U.S. EPA, Regulatory Impact Analysis for the Supplemental Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, October 2021. Available online: <https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-egclimate-review-updated.pdf>.



and other technical professions requiring advanced degrees, they mostly also employ high-skilled labor and trades professions complementing the current workforce at oil and gas operations.

The commenter (2367-BlueGreen Alliance) asserts that creating and sustaining jobs is tied strongly to the investment and implementation of a well-defined set of cost-effective technologies and practices in the oil and gas sector. The skill level needed, and consistent nature of leak detection and mitigation activities entailed by the methane standard—employed industry-wide—offer a new avenue for job sustainment compared to ‘business as usual.’ These activities will also rely on the existing oil and gas workforce, which is a good-paying, highly unionized sector.

The commenter (2367-BlueGreen Alliance) notes that many of the energy technology techniques and equipment date back several decades to the 20th century. The commenter contends that newer, less leak-prone machinery for oil and gas operations is increasingly available; a Datu report identifies 584 employment locations (referred to in the report as “employee locations”) for manufacturing, assembling, and providing installation and other services for methane mitigation technologies that could help reduce leaks and achieve the emissions reduction goals of the EPA methane standard.<sup>98</sup>

Commenter (2429-WOC) asserts that the economic case for federal methane regulations is compelling, and consumer demand for a low carbon fuel economy is growing.

The commenter (2429-WOC) notes that, nationally, it is estimated that oil and gas operators waste \$2 billion in methane annually, or enough to heat the homes of 10 million Americans a year.<sup>99</sup> For public and tribal lands, recent analysis of emissions and lost revenue is estimated at nearly \$500 million worth of gas in 2019 alone.<sup>100</sup> Numerous policy and government analyses have shown that reducing methane waste from oil and gas operations is one of the most feasible and cost effective ways to reduce GHG emissions.<sup>101</sup> In many cases, wasted methane can be captured and sold, paying for most, if not all, of the additional work needed to capture it. Recent data from the International Energy Agency suggest that up to 45 percent of wasted methane emission can be prevented at no net cost to industry.<sup>102</sup>

The commenter (2429-WOC) asserts that minimizing the waste of a valuable and non-renewable fuel source also has direct economic benefit to states and local jurisdictions that derive and depend on revenues from mineral severance taxes. The commenter estimates that in Wyoming between \$51 million to \$96 million worth of natural gas is lost due to intentional flaring, venting and careless leaks each year. This translates to \$8.8 million to \$16.1 million lost in annual royalty payments to the state. Of this amount, \$3.4 million to \$6.5 million was lost ad valorem revenue (property tax that goes directly to counties) that could have gone to the purchase of emergency equipment, or road and bridge repair, or human services like public health nurses and

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<sup>98</sup> Datu Research, Find, Measure, Fix: Jobs in the U.S. Methane Emissions Mitigation Industry, 2021. Available online: <https://www.daturesearch.com/wp-content/uploads/Datu-2021-Methane-Emissions-MitigationIndustry.pdf>.

<sup>99</sup> EDF Research Summary: <https://www.edf.org/climate/methane-studies>.

<sup>100</sup> Griot, et al. Onshore Oil and Natural Gas Operations on Federal and Tribal Lands in the United States Analysis of Emissions and Lost Revenue. 2023 Synapse Energy Economics Inc. January 23, 2023.

<sup>101</sup> International Energy Agency: Curtailing Methane Emissions from Fossil Fuel Operations. Oct. 2021.

<sup>102</sup> Id.

libraries.<sup>103</sup> The commenter asserts that these are critical revenue streams that taxpayers and budget-strapped communities deserve to see for the depletion of finite natural resources, particularly given ongoing statewide budget cuts.

Additionally, the commenter's (2429-WOC) experience in Wyoming suggests that there are tangible employment and economic benefits associated with developing a strong methane regulation economy. Currently, there are approximately 13 businesses in the methane emission mitigation industry in the state.<sup>104</sup> The commenter states that some of these businesses manufacture equipment needed for leak detection and repair work, while others are more focused on consulting and compliance services. As the standards around methane emissions are raised, this sector is poised to grow and create new jobs, helping Wyoming modernize its oil and gas infrastructure and stay competitive as consumer energy preferences change to favor low-carbon fuel sources.

Additionally, the commenter (2429-WOC) notes that in the last decade, demand for low-carbon and carbon-neutral fuel sources has increased dramatically, largely in response to consumer consciousness around climate change, and decreasing costs for renewable energy.<sup>105</sup> <sup>106</sup> Several of Wyoming's biggest oil and gas operators have already recognized this trend and are seizing on the opportunity by reducing sources of wasted methane in response to growing consumer demand for less carbon-intensive energy. Increasingly, emissions-intensive sources of natural gas represent an increasing liability for companies and investors, both domestically and abroad. The commenter notes, for example, in 2020 the French government blocked a \$7 billion liquified natural gas contract with U.S. producers over concerns that the gas was "too dirty."<sup>107</sup> Similarly, major institutional investors like BlackRock have started considering climate risk and vulnerability as investment criteria, and investor interest in funds with Environmental, Social, and Governance (ESG) benchmarks have skyrocketed in recent years. The commenter notes that these trends are expected to continue as governments, businesses, and citizens take measures to reduce carbon emissions in the future, and companies failing to mitigate environmental and social impacts will face increasing investor scrutiny and backlash.<sup>108</sup>

Response II-20-23: EPA acknowledges the challenge in assessing the employment impact of the regulation and acknowledges that there may be positive employment impacts in some locations and sectors. EPA is unable to quantify either positive or negative employment impacts at this time due to a lack of sufficient data, which commenters have not provided.

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<sup>103</sup> Wyoming Outdoor Council. 2018 Oil and Gas Waste Report. Available at: <https://wyomingoutdoorcouncil.org/wp-content/uploads/Wyoming-Natural-Gas-Waste-Report-WOC2.pdf>.

<sup>104</sup> Environmental Defense Fund. Methane Fact Sheet for Wyoming Methane Economy. 2021 Report.

<sup>105</sup> Pew Research Center. American's Largely Favor U.S. Taking Steps to become Carbon Neutral by 2050. March 2022. Available at: <https://www.pewresearch.org/science/2022/03/01/americans-largely-favor-u-s-taking-steps-to-become-carbon-neutral-by-2050/#:~:text=The%20new%20Pew%20Research%20Center,oil%2C%20coal%20and%20natural%20gas.>

<sup>106</sup> Lazard's Levelized Cost of Energy Analysis version 15.0. 2021. Available at: <https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf>.

<sup>107</sup> Politico, Foreign Policy. 21 Oct, 2020. "French Government Blocks U.S. LNG Deal as Too Dirty." <https://www.politico.com/news/2020/10/21/french-government-blocks-lng-deal-431028>.

<sup>108</sup> Larry Fink, Letter to BlackRock Investors. 2020. "A Fundamental Reshaping of Finance." <https://www.blackrock.com/corporate/investor-relations/2020-larry-fink-ceo-letter>.

Comment: Commenter (2248-NDPC) states that they do not believe the RIA performed for the November 21 proposal, and now the supplemental proposal appropriately justifies the economic burden of the proposed regulation on domestic oil and natural gas producers. The commenter expresses concern that the proposed rule will force producers to plug and abandon wells before their end of useful life. They report that this will have an economic impact on the North Dakotans and the Three Affiliated Tribes (Mandan, Hidatsa, Arikara) that are paid royalties for the oil and natural gas production. The commenter encourages careful consideration of the potential economic burdens on North Dakota's citizens and oil and natural gas producers when performing the regulatory impact analysis, including the useful life of equipment and wells.

The commenter (2248-NDPC) contends that over-regulation of the oil and natural gas industry increases production costs and discourages investment in the industry with little if any, environmental benefit. This can lead to higher electricity, heating fuels, food, and transportation prices, which disproportionately impacts low-income Americans. The commenter adds that, as inflation has increased, they have seen tangible evidence of this over the last few years.

Response II-20-24: With respect to the commenter's suggestion that the RIA does not appropriately justify the economic burden of the regulation, the EPA notes that the EPA's standard-setting duties and authority are derived under section 111 of the CAA, and its decisions are made within the confines of that authority. Although the EPA must consider the costs of control, it is not required to base the setting of standards on a broad-ranging benefit-cost analysis, and it has not done so here. The RIA prepared by the EPA under Executive Order 12866 may inform the standard-setting process, but it cannot provide the direct basis for the standards, nor does not "create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States..." (Executive Order 12866, Section 10).

With respect to the commenter's concern that the rule will force producers to plug and abandon wells before their end of useful life, EPA also developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and therefore the impact of lost revenue would be minimal.

Finally, with respect to price impacts, EPA models the impact of the rule on oil and natural gas supply in Section 4.1 of the Final RIA. EPA estimates that the reduction in U.S. oil production as a result of the Final Rule would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively.

#### ***20.4.2 Negative Economic Impacts***

Comment: Several commenters (2179-KIOGA, 2200-NuEnergy, 2205-Kriebel, 2211-Lambda Energy, 2220-WDEQ, 2223-TAEP, 2238-SOOGA, 2241-UDNR, 2248-NDPC, 2257-MOGA, 2279-US SBA, 2292-WVAG et al, 2294-OOGA, 2301-US CC, 2308-NSWA, 2309-NSWA, 2314-Miller Energy, 2322-ADEQ, 2403-PAO, 2446-IPAA, 2625-Fore Energy, 2696-Peters et al) assert that that the proposed rule will result in reduced production and associated revenues, an increased number of abandoned wells, job losses, and inflation, and that it unfairly impacts small businesses and underserved communities, and/or provide studies and references quantifying the negative impacts. Examples of these comments are presented in the following paragraphs. For additional comments on adverse impacts to small businesses, see section 20.3.5 of this Chapter. For additional comments on impacts on underserved communities, see section 20.5 of this Chapter.

Commenter (2292-WVAG et al) writes about the unnecessary costs of the Proposed Rule. The compliance costs have increased to \$1.8 billion annually from 2023 to 2035 compared to \$1.1 billion for the proposed rule. The Supplemental Proposal appears indifferent to the serious cost consequences it will place on the industry—making it one of the most expensive regulatory efforts the Biden administration has proposed.<sup>109</sup> For example, EPA recognized in the Proposed Rule that regulatory costs could be especially burdensome on smaller production operations and excluded them from the proposed fugitive emissions monitoring. 86 Fed. Reg. at 63,170. But the Supplemental Proposal would instead expand this frequent leak monitoring to all natural gas well sites (including wellhead-only sites), regardless of their estimated emissions. Now, all operators must conduct monthly, bimonthly, quarterly, or semiannual inspections or monitoring, depending on facility type—a costly undertaking. The Supplemental Proposal would also require emissions monitoring to continue until a facility has been “closed, including plugging the wells at the site and submitting a well closure report.” Thus, a huge class of defunct wells will now lead to continuing costs unless a producer is able to jump through a series of administrative hoops. And the agency has imposed strict zero-emission standards on pneumatic controllers (based on its sweeping judgment that such a standard is feasible at every site save a few in Alaska) and a zero-emission standard for pneumatic pumps. It is not even clear that these requirements can be met with tools readily available through existing supply chains. New and onerous requirements on flaring and dry-seal compressors also seem to lack any reasonable cost-benefit analysis to justify them.

Commenters (2314-Miller Energy, 2200-NuEnergy, 2625-Fore Energy) state that the proposed regulation conflicts with the State of Michigan’s Office of Oil, Gas and Mineral (OOGM) regulations. The commenters note that the premature plugging and abandoning of otherwise currently profitable marginal wells leaves valuable resources in the ground and is contrary to OOGM’s directive to prevent waste in the State of Michigan.

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<sup>109</sup> See Regulation Rodeo, AM. ACTION F. (2022), <http://bit.ly/3XZ52Pa> (last visited Feb. 3, 2023) (select “2021,” “2022,” and “2023” years).

Commenter (2625-Fore Energy) states that the proposed rules may decrease marginal wells life expectancy or result in well closure resulting in a forfeiture of the remaining reserves. The commenter recommends that EPA consider marginal well operations.

The commenter (2625-Fore Energy) contends that over the decades of the industry's operations, more regulatory rules have been written and been imposed on the business to improve environmental conditions and protect landowners' properties and recover the ultimate reserves from the wellbores and finally, properly plug and abandon the wells to protect groundwater and the adjacent air. The commenter asserts that during the first five decades of production, these goals were achievable because the gradual production decline still supplied funds to accomplish all manners of operations. Today the fees, charges and risk analysis are steep with profit margins boarding on bankruptcies. The commenter states that the decline rates for new successful wells is ten to twenty time higher than the major production of the 1940's and 1950's and is classified as marginal well status. The proposed rules may lead to well closures, causing loss of a portion of the remaining reserves, which could still be recoverable.

The commenter (2625-Fore Energy) states that decline rates play an important role in the management of wells, economic implications, capital investments, royalty, and environmental management. The commenter contends that this technique allows forecasting of the assets and preparation for the life remaining of the well(s) and the associated facilities. The commenter notes that without better understanding of the future rules projected to be imposed on the industry, producers may just walk away from their operations leaving the states and the state regulators with – orphan sites” to handle at tremendous costs. The commenter believes that changes to the federal CAA need to be clear to understand, workable for the producers to implement and substantially less costs for small businesses and marginal well producers.

Commenter (2314-Miller Energy) states that the proposed rule will result in an increased number of abandoned wells if small operators determine they cannot sustain operations with adequate profit margins. The commenter asserts that some operators may decide to abandon operations and transfer their liability to the state or federal government. That liability transfer impacts tax dollars and resources the government could have used elsewhere.

The commenter (2314-Miller Energy) notes that even with the state/federal bodies taking liability of abandoned wells, the wells likely do not receive the same attention from governmental officials as they do when managed by trained operators like the commenter. Lack of resources and knowledgeable oversight can create a large environmental impact on communities when releases occur.

Commenter (2308-NSWA) asserts that a review is necessary, given the likely resulting loss of production would cause higher energy costs for all Americans, job loss for oil and gas employees – the “hard working folks” President Biden talked about in his State of the Union – and lost revenue for local governments, businesses, and royalty owners (often retirees on fixed incomes).

Commenter (2292-WVAG et al) urges EPA to abandon its proposed rule and instead develop reasonable rules that protect a crucial sector to the economy. The commenter agrees that reducing methane emissions is a noble goal, one that industry is already working towards. The

commenter notes that the oil sector reduced methane emissions relative to production by 60 percent between 2011 and 2020.<sup>110</sup> The commenter reports that other reduction efforts are underway, like the Oil & Gas Methane Partnership 2.0 and the Texas Methane & Flaring Coalition. However, the commenter asserts that top-down, heavy-handed government control crushes the American energy sector. The commenter believes that the correct path to balance energy needs and environmental concerns is achieved by looking to American ingenuity and innovation, fostered by private initiative and state leadership.

Commenter (2301-US CC) states that the oil and natural gas industry is critical to U.S., and policies affecting the industry can have long-ranging repercussions. The commenter notes that the U.S. possesses enormous oil and natural gas deposits and has seen a marked revival in production due to advanced extraction techniques, leading to the nation becoming one of the world's largest producers of oil, natural gas, and related products. The DOE has characterized these trends as a "renaissance in oil and gas production in the U.S. over the past decade."<sup>111</sup> In 2019, the U.S. produced record levels of crude oil (12.2 million barrels per day) and natural gas (40.7 trillion cubic feet), increases of 11.3 percent and 10.6 percent from 2018 levels, respectively.<sup>112</sup> The U.S., as a result, enjoyed its best energy security since 1970<sup>113</sup> and became a net energy exporter for the first time since 1952.<sup>114</sup> The commenter contends that these achievements are due in no small part to America's shale revolution and advances in hydraulic fracturing technology.<sup>115</sup>

Beyond production statistics and industry trends, the commenter (2301-US CC) provides that the America's oil and natural gas industry is integral to the broader American economy. The production, transport, and refining of oil, natural gas, and related products creates well-paying jobs in a number of areas where such opportunities may otherwise be in short supply. The U.S. oil and natural gas industry's total employment impact is estimated at 11.3 million domestic jobs, or 5.6 percent of total U.S. employment.<sup>116</sup> And each direct job in the oil and natural gas industry supports an additional 3.5 jobs elsewhere in the U.S. economy.<sup>117</sup> Moreover, they add that these

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<sup>110</sup> See Tackling Methane Emissions, AM. PETROLEUM INST., <http://bit.ly/3l65lsP> (last visited Feb. 3, 2023).

<sup>111</sup> See U.S. Dep't of Energy ("DOE"), Valuation of Energy Security for the United States 12 (2017), [https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29\\_1.pdf](https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29_1.pdf).

<sup>112</sup> See Glob. Energy Inst. ("GEI"), U.S. Chamber of Commerce, Index of U.S. Energy Security Risk 5 (2020), [https://www.globalenergyinstitute.org/sites/default/files/2020-10/024036%20Global%20Energy%20Institute%20US%20Index\\_Web.pdf](https://www.globalenergyinstitute.org/sites/default/files/2020-10/024036%20Global%20Energy%20Institute%20US%20Index_Web.pdf).

<sup>113</sup> Id. (Table 1). In fact, after the United States received a record-high risk score of 100.9 in 2011, its score fell in seven of the subsequent eight years to a record low of 70.1 in 2019—a 5.5 percent decrease from 2018. Id. At 4.

<sup>114</sup> See U.S. Energy Info. Admin. ("EIA"), U.S. Energy Facts Explained, <https://www.eia.gov/energyexplained/us-energy-facts/imports-and-exports.php> (last updated June 10, 2022).

<sup>115</sup> See GEI, Index of U.S. Energy Security Risk, *supra* note 6, at 4 ("The application of hydraulic fracturing, horizontal drilling, and advanced seismic imaging has unlocked a tremendous oil and gas resource, turning energy scarcity into abundance."); see also DOE, Valuation of Energy Security, *supra* note 5, at 12 (attributing the United States' growth in oil and natural gas production to "technical innovation and entrepreneurial initiative").

<sup>116</sup> See PWC & Am. Petroleum Inst., Impacts of the Oil and Natural Gas Industry on the U.S. Economy in 2019. See [api-pwc-economic-impact-report.pdf](https://api-pwc-economic-impact-report.pdf).

<sup>117</sup> Id. At E-2.

jobs are spread throughout the country, as 31 states boast at least 100,000 jobs directly or indirectly supported by the oil and natural gas industry.<sup>118</sup>

The commenter (2248-NDPC) reports that North Dakota is ranked third in the nation in oil production, and their members produce 98 percent of the oil in North Dakota. North Dakota produced approximately 2.97 billion cubic feet of natural gas per day and 394 million barrels of oil in 2021, contributing significantly to supplying clean and cost-effective energy for Americans and America's energy independence. As an industry, they are proud of their environmental record and take their responsibility very seriously to be good stewards of the environment and lands on which we operate.

To demonstrate the significance of the oil and natural gas industry to North Dakota's economy, the commenter (2248-NDPC) notes that the taxes from oil and natural gas production accounts for 51 percent of North Dakota's tax revenue. Since 2008, the commenter reports that North Dakota's oil extraction and production tax revenues have generated over \$26 billion and provided over \$1.8 billion for education and \$5.9 billion in funding for communities and infrastructure across the state. The taxes have also contributed \$6.9 billion to the North Dakota Legacy Fund, which creates a perpetual source of revenue for the state's general fund and tax relief for its citizens.

Commenter (2220-WDEQ) urges EPA to consider the negative economic impacts in its cost-benefit analysis. The commenter contends that the supplemental proposal will have immense impacts upon Wyoming's economy that are not considered quantitatively or qualitatively in the RIA. The commenter points to the Wyoming State Geological Survey's January 2022 summary report titled "Oil & Natural Gas Resources in Wyoming" to explain the importance of oil and gas development to the State:

Oil and gas severance taxes and royalties contribute funding to state highway and county road construction and maintenance; water projects; local governments; school districts, scholarships, and the University of Wyoming and community colleges; and state-government agencies. Combined, oil and natural gas brought in more than \$372,000,000 in severance taxes for the state coffers during fiscal year 2021.<sup>119</sup>

The direct and indirect employment of tens of thousands of workers, as cited in the summary report:

In 2019, when Wyoming oil production was at an all-time high, these oil and gas extraction and support workers received upwards of \$1.1 billion in total wages to spend in their communities.

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<sup>118</sup> Id.

<sup>119</sup> Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, "Oil & Natural Gas Resources in Wyoming," January 2022 Summary Report.

Commenter (2257-MOGA) contends that the proposed rule will have major negative impacts on communities, and small businesses. The commenter urges EPA to consider the economic impacts.

The commenter (2257-MOGA) asserts that job losses would result from facility closures, layoffs of key personnel who keep the operations productive, marginal producing wells becoming uneconomic because of excessive regulatory obligations and the expense of those consulting charges to measure the nominal fugitive emissions or capital investments towards emission reduction. The commenter notes that once the producers close their doors and exit the small towns they support, the service companies have no clients to service, so they close their doors. This “snowball” effect results in once vibrant communities becoming ghost towns with only a spotlight to designate as an existing village.

The commenter (2257-MOGA) reminds EPA that many “underserved or overburdened communities” are often located in rural areas where oil and gas drilling and production provide jobs and sustains local economies. The commenter contends that the proposed rules will likely result in the early plugging of marginal wells that cannot absorb the initial implementation and ongoing costs of the proposed regulations. The plugging of wells will have a direct impact on associated small businesses, including hotels, restaurants, service, retail and other “mom and pop” stores that rely on the oil and gas industry to survive.

The commenter (2257-MOGA) asserts that the negative effects on small businesses will have large scale effects. Employment, income tax generation, private and government royalties, leasing contracts, restaurants, hotels, small communities, and families will be negatively affected.

The commenter (2257-MOGA) highlights the EPA data table provided to all Small Business Advocacy Review (SBAR) panel participants in June 2021. The table indicates that approximately 98.8-99 percent of all oil companies are owned by small businesses and that approximately 92.9-93.7 percent of all natural gas companies are owned by small businesses. [Referenced Table in the commenter’s letter: Total number of firms and small business percentage across multiple NAICS/Industry sectors.]

The commenter (2257-MOGA) notes that in Michigan alone, their membership constitutes around 650 members, many of which are small business and include oil and gas companies, environmental consultants, service and vendor companies, accounting and legal firms, general contractors, electricians, plumbers, welders and surveyors. In total, the oil and gas industry in Michigan directly or indirectly employs roughly 47,000 voting residents.

The commenter (2257-MOGA) presents a “Production Decline Curve” graph and notes initial production is significantly higher in the first years following completion. Higher initial production allows for the upfront consideration of long-term cost allocation, planning and implementation of new regulatory requirements such as determination, monitoring, calculations and reporting. [Comment letter includes a production decline curve graphic: Production Decline Curve (Exponential Decay Function). Age of production (years) on x-axis and BOE/Day on y-axis for 18 wells.]



The commenter (2257-MOGA) states that the proposed future EG, which include existing and marginal wells, do not allow initial capital investment or longevity planning considerations during initial high-margin return-on-investment realization. The commenter notes that many marginal wells in Michigan are often 3<sup>rd</sup> & 4<sup>th</sup> succession owner wells. The initial high-volume production was realized by previous owners. Each successive sale was based on an updated production formation reserve analysis and projected longevity of the marginal production. Should the EPA decide to include existing and marginal wells with the proposed NSPS regulations, small entity oil and gas producers with aging marginal wells would not have the associated production to substantiate an initial capital investment combined with ongoing annual costs based on diminishing economic return. This successive ownership paradigm represents a significant majority of oil and gas wells in Michigan.

Commenter (3604-Riverside Operating Company) owns and operates over 5,000 natural gas wells in northern Michigan and expresses concerns with respect to the proposed regulations, namely, inadequate review time to comment on these new rules, economic impact on marginal wells and the overall cost burden, as well as increased operational challenges in northern Michigan (*e.g.*, lack of sunlight in the winter months preventing solar power from being a viable option along with hundreds of well sites located in remote rural areas). The commenter supports the comments submitted by the IPAA and MOGA.

Commenter (2179-KIOGA) believes that EPAs proposed regulation will add to the cost of doing business and result in net job loss. The commenter reports that many of the operators in the upstream oil and gas segment operated at a loss in 2020 and 2021. A combination of crude oil demand destruction caused by the COVID-19 pandemic and a concurrent crude oil supply shock had a profound impact on the small businesses that make up the independent oil and gas industry in Kansas and across the nation. Owners/operators and their contractors cut capex by as much as 60 percent and cut operating costs by 30 percent or greater. Nearly 5,000 wells were shut-in in Kansas during 2020 with a loss of nearly \$810 million in lost oil output. Kansas producers worked in 2021-2022 to optimize supply chain relationships, improve operating efficiencies, and refocus capex on the most resilient short-cycle projects.

The commenter (2179-KIOGA) asserts that at a time when owners/operators are searching for ways to reduce operating costs to survive, EPA proposed methane regulation will likely measurably add to the cost of doing business. The commenter believes that owners/operators will be required to employ additional staff for field surveys/maintenance activities and documentation burdens. However, the commenter expects that this regulation will result in a net loss in jobs from the industry because expenditures will be required for compliance activities, not new revenue generation. Empirical evidence suggests LDAR testing on each Kansas lease would cost the Kansas oil and gas industry an estimated \$100 million annually. The commenter questions the need for the documentation requirements and recommends that EPA reduces these requirements.

Further, the commenter (2179-KIOGA) states that many of the small businesses that make up the Kansas oil and gas industry do not have the knowledge required to perform a fugitive emissions survey or to perform air emissions calculations for a well that has existed for multiple generations. These entities should not be burdened with having to figure out how to do so or

burdened with hiring, and paying for, an environmental consultant to perform the survey and calculations on their behalf.

The commenter (2179-KIOGA) urges EPA to consider the scope of the issue. The commenter notes that oil and natural gas production systems account for about 1.2 percent of the U.S. Greenhouse Gases Inventory (GHGI). Low production wells account for about 10-11 percent of U.S. production; therefore, their emissions would be in the 0.10-0.20 percent range of the GHGI. There are about 1,000,000 existing oil and natural gas wells. Approximately 150,000 of these wells have been regulated under NSPS OOOO and now NSPS OOOOa. That number grows each year. Of the remainder, 770,000 are low production wells. Nationally, low production wells average about 2.5-2.7 barrels per day if they are oil wells and 22- 24 mcf/d if they are natural gas wells.

The commenter (2179-KIOGA) contends that subjecting these wells to the NSPS LDAR requirements puts them in severe economic jeopardy. Even EPA recognized this reality when it did not impose this LDAR program on low production wells in its October 2016 Control Techniques Guidelines (CTG) for existing oil and natural gas production facilities operating on Ozone Nonattainment areas.

Further, the commenter (2179-KIOGA) urges EPA to consider the different emissions profiles between high and low production wells. The commenter agrees with the January 2021 International Energy Agency (IEA) regulatory roadmap and toolkit focused on “Driving Down Methane Leaks from the Oil and Gas Industry” that details that, “understanding the nature and magnitude of your emissions will be critical to designing sound regulations.”

The commenter (2179-KIOGA) reports that one key aspect of the independent component of the oil and natural gas production industry is its breadth — spanning from large, high production wells to low production wells. These wells do not all have the same emissions profiles, and those different profiles should be considered in regulations. The commenter notes that low production wells are those that produce 15 barrels/day (or 90 mcf/d) or less. The national average low production oil well is about 2.5 barrels/day, and the low production natural gas well is about 24 mcf/d. Of the roughly one million active oil and natural gas wells in the U.S., about 750,000 are low production wells, typically operated by small businesses. The commenter asserts that the regulatory structure applied to low production wells is significant because their viability is so dependent on their cost of operation.

Commenter (2211-Lambda Energy) contends that the proposed regulations will result in marginal well closures, job losses, and additional abandoned wells. The commenter states that the additional financial burden and increased costs of the proposed regulations would make uneconomic and, in all likelihood, require the shut in, between 200 to 300 marginal wells, and would result in the loss of at least 15 jobs of well operators and processing, gathering, and back-office personnel. The commenter notes that these closures would also result in significant lost revenue to the company and its employees, vendors and royalty owners, the largest of which is the Michigan Department of Natural Resources. In addition, the commenter states that these regulations might also result in many wells being abandoned and ending up in the State of Michigan’s orphan well plugging program, and thus shifting that liability to taxpayers.

Commenter (2294-OOGA) states that the Supplemental Proposal threatens the continued viability of the oil and gas industry in Ohio. The economic ramifications of a rulemaking that potentially halts further development of oil and natural gas in Ohio cannot be ignored as the industry generated approximately \$97 Billion in investments in Ohio since 2011,<sup>120</sup> and provides nearly 200,000 Ohio jobs.<sup>121</sup> Relatedly, the areas in which the oil gas industry predominantly operates and, in turn, provides necessary and critical services – i.e., overburdened and underserved rural communities (e.g., southeast Ohio) – are the areas that will suffer the economic consequences. The commenter notes that this effectively results in “inverse” environmental justice in these communities. That is, rural families and farmers whose homes are heated by the oil/natural gas supplied directly from a production well lose the direct energy source when wells are closed and are forced to bear the costs of switching to other energy sources; jobs are lost; tax revenues are lost; and investment in critical infrastructure comes to a halt.

Commenter (2292-WVAG et al) asserts that the proposed rule will increase the costs of production – especially for low production wells. The commenter contends that, since more low-producing wells are owned by small businesses, many small businesses will be forced to close (in return for little benefit). The commenter notes that with 80 percent of U.S. wells producing fewer than 15 barrels a day, the compliance costs and associated closure will seriously hurt American consumers.<sup>122</sup>

The commenter (2292-WVAG et al) expresses concern with the scale of the proposed rule. The commenter notes that West Virginia alone has over 55,000 active and 12,000 inactive oil & gas wells. But even West Virginia’s production and facilities numbers are small when compared to places like Texas—which currently monitors approximately 161,000 active oil wells and 87,000 active gas wells—or other states like Alaska, Louisiana, Oklahoma, and North Dakota. The commenter states that the Supplemental Proposal will result in significantly increasing costs at hundreds of thousands of facilities. The commenter expresses concern that the Supplemental Proposal excludes a meaningful analysis and discussion of whether these increases would fall within a reasonable range. Instead, the commenter notes that EPA satisfied itself by declaring that the “\$1,970/ton of methane reduction” was below the \$2,185/ton threshold that it found reasonable six years ago. The commenter contends that, without any supporting data or analysis, these numbers are next to meaningless; it is not enough for EPA to note that it has done something similar before and dub its cost-benefit analysis complete.

Commenter (2322-ADEQ) contends that EPA did not adequately consider the impacts on small businesses and marginal well owners and operators. The commenter asserts that removing the 3 ton per year (tpy) creates an unmanageable number of sources for regulatory authorities to inspect and permit. Further, the commenter states that removing the threshold also disproportionately causes negative economic effects for individuals and families in rural areas (i.e., underserved communities) who receive minimal financial benefits from small sources located on their private property. The commenter disagrees with EPA’s decision to promulgate

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<sup>120</sup> [https://cdn.bfldr.com/AHJE351Z/at/jrb837bsbpc3gn3x5zksqtpc/Shale\\_Dashboard\\_Q3Q4\\_2021\\_FINAL\\_45\\_.pdf](https://cdn.bfldr.com/AHJE351Z/at/jrb837bsbpc3gn3x5zksqtpc/Shale_Dashboard_Q3Q4_2021_FINAL_45_.pdf).

<sup>121</sup> [https://ohiolmi.com/\\_docs/OhioShale/2021AnnualShale.pdf](https://ohiolmi.com/_docs/OhioShale/2021AnnualShale.pdf).

<sup>122</sup> U.S. ENERGY INFO. ADMIN., THE DISTRIBUTION OF U.S. OIL AND NATURAL GAS WELLS BY PRODUCTION RATE 3 (Dec. 2022), <https://bit.ly/3jqWhOI>.

the Proposed Rule. The commenter urges EPA to include exemptions for small sources as initially proposed, and to thoroughly evaluate the effect that the requirements will have on small businesses and individual families who have domestic wells on their property.

The commenter (2322-ADEQ) notes that in 2022 approximately 16,000 oil and gas wells were producing in Arkansas by approximately 300 operators.<sup>123</sup> The commenter notes that Eighty-five percent of the 7,000 producing oil wells in southern Arkansas and fifty percent of the 9,000 producing natural gas wells in northern Arkansas are “stripper” or marginal producing wells. These wells cannot provide sufficient financial benefit to the well operators to fund the additional measures required for compliance with the Proposed Rule. According to 2020 Census data, 58 oil and gas producers in Arkansas reported having fewer than five employees. The commenter notes that most of these marginal production wells are located in rural areas of the state, where annual income is typically on the lower end of the scale, and the Proposed Rule will negate the income currently generated for the landowners and tax revenues for those small communities.

The commenter (2322-ADEQ) states that the average household income in Arkansas in 2019 was \$47,600; compared to national percentiles using EPA’s EJ screening tool, a majority of the state falls within the 60 to 90<sup>th</sup> percentile for “low-income,” with a good portion falling into the 90-100<sup>th</sup> percentile.<sup>124</sup> The commenter notes that the oil and gas industry is a significant contributor to local economies and individual financial stability in rural areas in the state where employment opportunities are often limited. Census data from 2017 established that over 3,700 employees reported as working in the oil and gas industry in Arkansas. The average annual salary in the state for oil and gas industry jobs in 2017 was just over \$52,000, 10 percent higher than the average salary statewide. The commenter contends that this is a substantial portion of revenue that makes its way back into the coffers of rural communities that lack the combined resources of more populated communities. The commenter states that the Proposed Rule burdens small producers and individual owners in a way that threatens to cause closures and shutdowns at otherwise productive and economically beneficial well sites, and the impact to rural communities (where a majority of these wells are located) has not been properly considered or explored by EPA.

The commenter (2322-ADEQ) contends that states rich in energy production and energy resources used for nationwide benefit historically have populations of lower socioeconomic status; these citizens welcome oil and natural gas activities and the resulting energy production in their communities because it provides stable tax revenue and well-paying jobs in areas where economic development (and employment) is scarce. The commenter recommends that EPA consider that these already economically burdened states and populations inherently bear more of the weight for any requirements imposed on the oil, gas, and energy industries.

Commenter (2446-IPAA) urges EPA to consider the proposed rules forced shutdown of oil and natural gas production that will result in lost revenue, lost jobs, impact on secondary businesses, negative impact on the American economy, and worldwide impacts.

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<sup>123</sup> Arkansas Oil and Gas Commission.

<sup>124</sup> <https://ejscreen.epa.gov/mapper/> Arkansas map, low income filter, shown by county.

The commenter (2446-IPAA) notes that supply disruptions occur around the world at a regular frequency. The disruptions may last for a few months (i.e., a terrorist bombs a transportation pipeline, and the pipeline needs to be repaired) to several years (i.e., economic penalties enacted to encourage Iran to abandon their nuclear program). The commenter notes that in some cases, the supply disruption only serves to redirect where oil is processed (the U.S. cannot purchase Venezuelan crude oil, but other countries such as China may process the crude oil). Unlike a supply disruption, when low production wells are plugged, the production will never be recovered.

The commenter (2446-IPAA) states that if low production wells are shut down, this will take approximately ten percent of the American oil production and natural gas production offline, and approximately one percent of world oil production offline. This change in production will have long term, negative consequences for the American economy from higher energy prices and from the loss of jobs. When low production wells are plugged, this production is lost forever.

The commenter (2446-IPAA) contends that EPA needs to consider these negative consequences in the economic analysis of the proposed regulation. For example, the direct lost revenue to oil and natural gas companies and royalty owners if American oil production is diminished will be almost \$30 billion per year (1,000,000 barrels of oil x \$80/barrel x 365 days per year). This does not include the secondary financial loss to service companies or other businesses that derive revenue from oil and gas production (such as restaurants, automotive companies, accounting companies, office supply stores, and legal firms).

The commenter (2446-IPAA) reports that historically, when the crude oil supply and demand balance has been disrupted by two to three percent, there have been large changes in the price of crude oil. While the U.S. does not have specific controls in place to manage the balance of supply and demand (it permits market forces to drive the supply and demand balance), OPEC actively controls production to balance supply and demand. OPEC only has 3 million to 5 million barrels/day of spare capacity to manage the supply and demand changes. The commenter states that the supply and demand balance is typically controlled within one to three percent of worldwide crude oil production. Permanently removing a million barrels of production will have a measurably negative impact on the long-term supply of crude oil. The negative impact will be measured by higher crude oil prices.

Additionally, the commenter (2446-IPAA) urges EPA to include “economic” considerations in the rule language for certification. The Supplemental Proposal acknowledges that economic feasibility can be factored in to determining when is appropriate to utilizing an unloading method that vents to the atmosphere. However, the commenter notes that the proposed regulatory language in the context of record keeping and certification makes no mention of economic feasibility:

I certify that the technical and safety infeasibility justification of needing to use a non-zero emitting liquids unloading method for all liquids unloading events at the well affected facility was prepared under my direction or supervision. Based on my professional knowledge and experience, and inquiry of personnel involved in the

infeasibility justification, the certification submitted herein is true, accurate, and complete.<sup>125</sup>

According to the commenter (2446-IPAA), there are limited instances where an engineer or qualified professional would certify “infeasibility” – pour enough money at a particular issue, most technical and/or safety issues can be resolved or are “feasible.” The “economic” considerations allowed for the Supplemental Proposal must be included in the rule language for the certification.

Commenter (2238-SOOGA) states that the Supplemental Proposal is overloaded with stringent emissions standards and related compliance requirements that are impractical, technically infeasible, cost-prohibitive, overly burdensome, and otherwise unreasonable. The commenter contends that the impacts of such requirements are disproportionately borne by small businesses and operators of low production wells. Relatedly, the commenter notes that the areas in which the oil gas industry predominantly operates and, in turn, provides necessary and critical services – i.e., overburdened and underserved rural communities such as found in southeast Ohio and western West Virginia – are the areas that will suffer the economic consequences stemming from the Supplemental Proposal. The commenter asserts that this effectively results in environmental injustice and social injustice in these communities. That is, rural families and farmers whose homes are heated by an oil/natural gas production well are forced to bear the costs of switching to other energy sources such as burning wood and/or coal which may be more detrimental to the environment and indoor air quality. Consequently, jobs are lost; tax revenues are lost; and investment in critical infrastructure comes to a halt.

Response II-20-25: With respect to overall oil and natural gas production and prices, EPA disagrees with commenters’ assertions that the regulation would have profound impacts. Several commenters allege severe impacts but fail to provide specific information to support those claims. EPA models the impact of the rule on oil and natural gas supply in Section 4.1 of the Final RIA. EPA estimates that the reduction in U.S. oil production as a result of the Final Rule would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively.

With respect to marginal wells, EPA disagrees with the suggestion of one commenter (2446-IPAA) that all low production wells could be shut down, resulting in a loss of 10% of domestic production. EPA notes that it developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. In any case, the analysis suggests that to the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells.

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<sup>125</sup> Page 250 of the Proposed Regulatory Text at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce>.

Also with respect to marginal wells, EPA rejects commenter's (2179-KIOGA) suggestion that methane emissions from low production wells are proportionate to their production levels. Recent studies have suggested that low production, or marginal, wells account for roughly half of methane emissions from oil and natural gas production (see Chapter 6 of the TSD).

With respect to impacts on small businesses and rural communities, EPA notes the revised IRFA and FRFA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. For example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. Additionally, both NSPS OOOOb and EG OOOOc include provisions that could be pursued for an alternative but equivalent compliance option under NSPS OOOOb or equivalent or less stringent requirements considering remaining useful life and other factors (RULOF) under EG OOOOc under a state plan. 40 CFR 60.5399b (What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?) of NSPS OOOOb provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. See section XIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for state plan requirements and sub-section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

With respect to potential employment impacts, EPA acknowledges the challenge in assessing the employment impacts of the regulation. To the extent that regulatory costs lead to reduced production, sector employment could be reduced, though this is not guaranteed as firms could simultaneously reallocate expenditures on productive inputs away from capital and towards labor because of the regulation. In addition, as noted by some commenters, the regulation may also increase employment by increasing the demand for compliance-related labor. The net effect is ambiguous without sufficient data, which hasn't been provided by commenters.

In response to the commenter that provides examples where the December 2022 Supplemental Proposal's expanded requirements, the EPA addressed affected facility/designated facility requirements specific comments that parallel this commenter's concerns under other Chapters of this RTC. For EPA's response to comment on well site fugitive emissions requirements, see Volume II, Chapter 4 (Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations) of this RTC. This Chapter also includes EPA's responses to comments on well closure requirements (see section 4.1.6 Well Closure Requirements) of Volume II, Chapter 4. For EPA's response to comments on process controllers and pumps, see Volume II, Chapters 7 (Process Controllers) and 8 (Pumps).

With regards to the December 2022 Supplemental Proposal proposed dry seal compressor requirements, see discussion in section XI.G.1 (Redefining the affected facility to include centrifugal compressors with dry seals and the proposed standard) of the final rule preamble. Based on comments received on the December 2022 Supplemental Proposal, the EPA has revised the proposed volumetric flow rate performance standard for centrifugal compressors with dry seals to be 10 scfm/seal (i.e., representing a maximum flow rate applicable to all dry seals).

For the liquids unloading comment, where the commenter urges EPA to include “economic” considerations in the rule language for certification, see section XI.F.3.b (Recordkeeping and reporting requirements) of the final rule preamble. As a work practice standard, the engineering certification statement that would be required under the December 2022 Supplemental Proposal, which would have required an explanation of why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons, is unnecessary and has been removed from the final rule.

See also section X (Summary of Final Standards NSPS OOOOb and EG OOOOc) of the final rule preamble for a summary of the final affected facility/designated NSPS OOOOb and EG OOOOc requirements.

Comment: Commenter (2219-WOGCC) states that they are the state regulatory agency for the oil and gas industry in Wyoming. They report that their agency regulates all aspects of wells in the state including rules on venting and flaring, well drilling and completions, well operations, and well plugging, while the Wyoming Department of Environmental Quality (WDEQ) regulates air quality at oil and gas locations. In addition to WOGCC and WDEQ regulations, they note that wells on federal lands must also comply with BLM regulations, inserting layers of regulations and regulatory agencies that operators must consider.

The commenter (2219-WOGCC) complains that the EPA proposed rule creates yet another regulatory burden that will be placed on wells and operators in Wyoming. When evaluated in conjunction with the recently announced BLM rule on waste prevention, they contend that these rules become sometimes duplicative, sometimes conflicting, but always burdensome on operators to navigate how to remain in compliance with each. Not only does EPA's proposed rule place these burdens on an operator related to air quality regulations, but the commenter states that the EPA is proposing regulations outside of its authority on issues such as well plugging and financial assurance. According to the commenter, these issues are clearly within the state's and BLM's regulatory authority, not EPA. The commenter asserts that the EPA should remove the proposed requirements and suggest regulations only on issues that it is granted authority over.

Response II-20-26: Once the EPA establishes NSPS for a particular source category, the EPA is required in certain circumstances to issue EG to reduce emissions from existing sources in that same source category. Specifically, CAA section 111(d) requires that the EPA prescribe regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. The EPA addresses this CAA requirement both through its promulgation of general implementing regulations for CAA section 111(d) as well as through specific EG. Please see section IV.A. of the final preamble of additional discussion on EPA's statutory obligations under CAA section 111. Furthermore, to be



clear, the final EG OOOOc in no way impacts states' ability to regulate sources under state law. Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

Please see section VI.A in the final preamble discussing related federal actions. EPA notes that certain Federal agencies also regulate aspects of the oil and natural gas industry pursuant to their own authorities. For example, BLM specifically has the express authority and responsibility to regulate both for the prevention of waste and the protection of the environment for operations on Federal and Indian lands. This responsibility includes promulgating regulations to reduce the waste of natural gas from oil and gas leases administered by the BLM.

Lastly, please see the final Supporting Statement for EG OOOOc in the docket for this rulemaking, which EPA estimates information collection activity burden for the states.

### ***20.4.3 Energy Impacts***

Comment: Several commenters (2166-ODNR, 2202-TOGA, 2241-UDNR, 2248-NDPC, 2301-US CC, 2308-NSWA, 2466-IPAA, 2544-PBPA) assert that the supplemental proposal has substantial direct negative effects on energy supply and energy security and/or provide studies and references supporting the adverse impacts. Some of the commenters note that decreasing U.S. production will result in increased oil and gas production in countries with lenient or non-existent environmental regulations, thereby increasing global emissions. Other commenters urge EPA to consider the effects of diminished energy supply and downstream effects when finalizing the proposed rule and recommend that EPA balance requirements with support for maintaining domestic oil and gas production. Examples of some of the comments are presented in the following paragraphs.

Commenter (2241-UDNR) states the rule has potential negative impacts on all Utahns. For example, they note that there is a looming global LNG shortage. As a consequence, "[n]atural gas utilities try to dampen price increases for their customers by hedging and purchasing natural gas in advance at lower prices, but there is nothing they can do about global supply shortages. Ultimately, the price increases are passed on to customers, who have no option but to pay the higher bills." These increased prices passed to consumers hurts low-income Americans the most. For example, "for many struggling families, higher prices can mean being forced to choose between heat, food or medication. About 29% of Americans who were surveyed had to reduce or forego expenses for basic household necessities to pay an energy bill in the last year, according to the U.S. Census Bureau. And that was before natural gas prices started to rise." The commenter provides a graph in their comment letter that illustrates a sharp increase in consumer prices (from the U.S. Energy Information Administration), which shows that nearly half of all U.S. households heat with natural gas, and that these "households that use natural gas as the primary space heating fuel will spend about \$930 this winter, 28 % more than they spent last winter." [Comment letter includes a table that shows U.S. average house expenditures with various heating methods between Oct-Mar. Costs are given for a base case, assuming 10 percent colder, and 10 percent warmer temps.]

Commenter (2241-UDNR) states that there is also a direct relationship between higher energy prices and a correlating food security issue is highlighted in other sources. The commenter states that these "[u]nexpected increases in energy prices (also called energy price shocks) can adversely affect food security; purchasing food and gasoline and paying utility bills compete for the same limited resources of low-income households. For poor families, rising energy prices create a difficult tradeoff between buying enough food, staying warm, or having enough gas for the car. Energy price shocks may be particularly detrimental to low-income households because they have fewer resources available to absorb the unplanned higher expense. While previous research has indicated that low-income households reduce the amount of food they buy in response to unexpected increases in energy prices, it is not clear whether these price shocks are large enough to dent a family's food security."<sup>126</sup>

The commenter (2241-UDNR) notes this correlation is backed up by a recent study conducted by the USDA Economic Research Service, which "explored the relationship between energy price shocks and food security, as well as two other measures of food hardship or distress, and found that price shocks in each energy source in the analysis—gasoline, natural gas, and electricity—caused an increase in the probability of a household becoming food insecure and/or experiencing two other food-distress indicators. The magnitude of the response was higher for low-income households compared to the average response for all households."<sup>127</sup> Accordingly, the requests consideration on how the proposed rule will contribute to potential energy shortages and what they believe could be the threat of disastrous correlating energy shocks.

Commenter (2241-UDNR) believes as EPA moves forward with the proposed rule/supplemental proposal, the state would encourage it to examine in depth the potential negative implications and hardships that will be imposed on Utahns and Americans nationwide if this rule is finalized. As stated, they conclude that there is a looming natural gas shortage in this country, and if rules are put in place that make production of said natural gas even harder, then surely they believe we will see negative social justice and environmental justice ramifications (such as those described above) manifest themselves in the form of increased human suffering.

Commenter (2301-US CC) explains that, at the consumer level, energy costs represent a sizable portion of American consumer's budgets, whether it be the prices consumers pay at the pump, the amounts spent on power or heating bills, or the price tags on countless consumer goods.<sup>128</sup> Oil and natural gas are critical to allowing Americans to affordably power the vehicles that deliver their products or allow them to commute to work, and represent the vast majority of

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<sup>126</sup> Charlotte Tuttle, Unexpected Hikes in Energy Prices Increase the Likelihood of Food Insecurity, USA ERS, available at: <https://www.ers.usda.gov/amber-waves/2017/july/unexpected-hikes-in-energy-prices-increase-the-likelihood-of-food-insecurity/#:~:text=Natural%20gas%20price%20shocks%20increased%20the%20probability%20of,low-income%20households%20in%20cold%20States.%20Embed%20this%20chart> (2017).

<sup>127</sup> Id.

<sup>128</sup> See DOE, Valuation of Energy Security, *supra* note 5, at 31–34; Josh Mitchell, Soaring Energy Prices Raise Concerns About U.S. Inflation, Economy, Wall St. J. (Oct. 10, 2021), [https://www.wsj.com/articles/soaring-energy-prices-raise-concerns-about-u-s-inflation-economy11633870800?st=rx3j3jxhf6ivnp7&reflink=desktopwebshare\\_permalink](https://www.wsj.com/articles/soaring-energy-prices-raise-concerns-about-u-s-inflation-economy11633870800?st=rx3j3jxhf6ivnp7&reflink=desktopwebshare_permalink).

energy consumed for these transportation purposes.<sup>129</sup> In fact, transportation costs are the second-largest expense for most households' annual budgets, often accounting for as much as 20 percent to 25 percent of annual income.<sup>130</sup> Further, half of all American households rely on natural gas for heating their homes and water, cooking, and drying clothes, making them especially sensitive to fluctuations in the price of natural gas.<sup>131</sup> Because much of this energy-related consumer spending is essential, "[c]onsumers can't easily cut [energy] consumption on short notice, as they can with discretionary purchases, so higher prices act as a tax, draining the money they have available to spend on other goods and services."<sup>132</sup> When consumers elect to instead cut discretionary spending, the reduction carries negative consequences for the broader economy and helps explain why high energy prices often precede recessions.<sup>133</sup>

Moreover, the commenter (2301-US CC) adds that natural gas has become essential to the electric generation and industrial sectors. In fact, since 2005, the annual consumption of natural gas has grown by nearly 41 percent, or 9 trillion cubic feet, with the electric generation (up 60 percent) and industrial (up 28 percent) sectors comprising nearly 90 percent of the increase in annual consumption.<sup>134</sup> Natural gas has displaced other power generation sources to become the primary fuel for electric power generation over the past 10 years.<sup>135</sup> Further, manufacturers use oil and natural gas as a feedstock or as a fuel for production. A stable supply of oil and natural gas is critical to ensure adequate production of petrochemicals, medical devices, plastics, solvents, fertilizers, and many other products that American consumers use on a regular basis.<sup>136</sup>

Commenter (2301-US CC) recommends that EPA also recognize the wide variety of landscapes and regions production occurs, often remote locations with limited infrastructure or onsite personnel. The commenter contends that by imposing requirements that assume the regular availability of on-site staff or electricity, EPA risks undermining U.S. energy diversity by reducing the economic viability to continue operating at many of these locations, particularly when they contain existing sources that would be subject for the first time to methane regulations.

The commenter (2301-US CC) states that energy security plays a key role in the U.S.' economic success by ensuring the availability of affordable, reliable, and diversified sources of energy

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<sup>129</sup> See U.S. Dep't of Energy ("DOE"), Valuation of Energy Security for the United States 32–33 (2017), [https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29\\_1.pdf](https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29_1.pdf).

<sup>130</sup> Id. At 33.

<sup>131</sup> See EIA, Natural Gas Explained: Use of Natural Gas, Use of natural gas – U.S. Energy Information Administration (EIA) (last updated Nov. 16, 2022); see also DOE, Valuation of Energy Security, *supra* note 5, at 34.

<sup>132</sup> See Mitchell, *supra* note 16; see also DOE, Valuation of Energy Security, *supra* note 5, at 32.

<sup>133</sup> See Mitchell, *supra* note 16; see also DOE, Valuation of Energy Security, *supra* note 5, at 32 ("As a result of those higher [transportation fuel] prices, households and businesses are able to spend less on other goods and services and invest less. Those decisions create indirect costs on the economy, with effects that can last for several quarters.").

<sup>134</sup> See Center for Climate and Energy Solutions ("C2ES"), Climate Solutions: Technology Solutions: Natural Gas, <https://www.c2es.org/content/natural-gas/> (last visited Jan. 11, 2023).

<sup>135</sup> Id.

<sup>136</sup> See IEA, The Future of Petrochemicals: Towards More Sustainable Plastics and Fertilisers 11 (2018), The Future of Petrochemicals – Analysis – IEA. (Petrochemicals "are set to account for more than a third of the growth in oil demand to 2030, and nearly half to 2050, ahead of trucks, aviation and shipping.").

capable of fueling our national economy.<sup>137</sup> In an increasingly global energy market, the U.S. has grown more vulnerable to foreign energy disruption—including not just political disruptions, but also cybersecurity threats, extreme weather events, and other sources of risk to affordability, reliability, and/or availability.<sup>138</sup> The commenter asserts that the recent surge in domestic production, however, has helped safeguard America’s energy security from such foreign disruptions, while simultaneously helping the entire global energy market weather such volatilities. The commenter notes that the Department of Energy (DOE) has found that increased production of oil and natural gas has “improved domestic, and thus global, energy security in a variety of ways” and has repeatedly prevented spikes in energy prices that could threaten both the U.S. and global economy.<sup>139</sup> The commenter believes that the U.S. is fortunate to presently have a stable supply of domestic oil and natural gas production, but this valuable supply is vulnerable to dissipation if overly burdensome regulatory regimes, or other factors, impede the development of available resources.

The commenter (2301-US CC) states that the impact that energy shortages and reliance on foreign energy sources can have on economic stability—and the counterbalancing benefits of strong domestic production—has been highlighted by recent events in Europe. In contrast to the U.S., which has a stable domestic supply of natural gas, Europe imports much of its natural gas supply—including a significant percentage from Russia—and is therefore far more vulnerable to geopolitical disruptions. The commenter asserts that the ongoing Ukraine crisis has placed this vulnerability on full display, as reductions in natural gas imports from Russia have spurred an energy crisis across the continent.<sup>140</sup> The commenter reports that the European Union, as a result, has had to mitigate shortages with voluntary and mandated energy rationing measures,<sup>141</sup> and consumers have had to grapple with sharp price increases in everyday consumers goods, as the prices for energy inputs skyrocket.<sup>142</sup> Further, many of Europe’s industrial sectors have struggled to keep operating.<sup>143</sup> And the downstream consequences of the energy crisis are wide-ranging and will likely be felt for years to come: “The IMF calculated in mid-July that for Hungary, Slovakia, and the Czech Republic a full cut off of natural gas from Russia could drop GDPs by up to 6 percent. Global economic growth would drop by 2.6 percent in 2022 and another 2 percent in 2023. On a human level, some people will not have heating this winter; others will

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<sup>137</sup> See Int’l Energy Agency (“IEA”), Energy Security: Reliable, Affordable Access to All Fuels and Energy Sources, <https://www.iea.org/topics/energy-security> (last visited Jan. 10, 2023).

<sup>138</sup> See U.S. Dep’t of Energy (“DOE”), Valuation of Energy Security for the United States 2, 12 (2017), [https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29\\_1.pdf](https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29_1.pdf).

<sup>139</sup> *Id.*

<sup>140</sup> See Mark Flanagan et al., Int’l Monetary Fund, How a Russian Natural Gas Cutoff Could Weigh on Europe’s Economies (July 19, 2022).

<sup>141</sup> See Ewa Krukowska & Lenka Ponikelska, EU to Propose Mandatory Power-Demand Cut and Levy on Profits, Bloomberg (Sept. 12, 2022), <https://financialpost.com/pmn/business-pmn/eu-proposes-mandatory-power-demand-cut-and-tax-on-profits>.

<sup>142</sup> See Lyubov Pronina & Petra Sorge, From Beer to Tomatoes, Europe’s Energy Crisis is Spilling Over, Yahoo (Sept. 13, 2022), <https://financialpost.com/pmn/business-pmn/from-beer-to-tomatoes-europes-energy-crisis-is-spilling-over>.

<sup>143</sup> See Liz Alderman, ‘Crippling’ Energy Bills Force Europe’s Factories to Go Dark, N.Y. Times (Sept. 19, 2022), <https://www.nytimes.com/2022/09/19/business/europe-energy-crisis-factories.html?smid=urlshare>; Eleanor Beardsley, Europe Fears Its Industries Will Jet to the U.S. as Energy Costs Force Plant Closures, NPR (Nov. 25, 2022), <https://www.npr.org/2022/11/25/1138573080/energy-costs-europe-uscompanies-close-plants-eu-economy>.

have to choose between warmth and food.”<sup>144</sup> It has been the influx of U.S.-produced liquified natural gas (LNG) to European markets that has helped blunt some of the more devastating consequences of the European energy crisis.<sup>145</sup>

By contrast to the European Union, the commenter (2301-US CC) asserts that one key factor in the relative stability of U.S. energy prices is supply diversity, which “reduces the likelihood that disruptions to supply or threats to production areas, trade, or distribution routes—whether caused by weather, terrorism, or geopolitics—significantly disrupt U.S. access to physical energy supplies.”<sup>146</sup> In addition to global geopolitical events like those noted above, domestic disturbances can hinder the ability to get energy to consumers. The commenter notes that localized weather events could cause certain sources of energy to be taken offline for periods of time, meaning that redundancy in the availability of energy sources is important to ensuring that our economy is able to continue to function smoothly. In addition, heat waves and winter freezes can result in short term and localized spikes in energy demand, as there are regions of our country that are particularly vulnerable to such disruptions because of concentrations of supply or transportation issues. Because oil and natural gas can be strategically stored without relying on battery storage, they are better suited for preparing for an energy disruption than are many renewable energy sources.<sup>147</sup>

The commenter (2301-US CC) states that, fortunately, the U.S. oil and natural gas industry is already “highly diversified because it is comprised of many privately held businesses that respond to market forces to increase or decrease production of oil and natural gas.”<sup>148</sup> Domestic oil and natural gas production also provides source diversity because it occurs over a broad set of geographic regions, so that significant oil and natural gas production is possible from eastern states such as Pennsylvania, to Texas and southwestern states like New Mexico, to Colorado and Wyoming in the west, as well as North Dakota and Alaska.

The commenter (2301-US CC) notes that even as the U.S. has attained record levels of oil and natural gas production and, in turn, increased its energy security, the nation has seen a sharp decline in GHG emissions. Overall CO<sub>2</sub> emissions from fossil fuel combustion have decreased by 1,409.4 million metric tons of CO<sub>2</sub> equivalent (MMT CO<sub>2e</sub>) relative to 2005 levels—a

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<sup>144</sup> See Suriya Jayanti, Europe’s Energy Crisis Is Going to Get Worse. The World Will Bear the Cost, *Time* (Aug. 30, 2022), <https://time.com/6209272/europes-energy-crisis-getting-worse/>.

<sup>145</sup> See Steven R. Miles, Gabriel Collins & Anna Mikulska, Baker Inst. For Pub. Pol’y, US Needs LNG to Fight a Two-Front Gas War (Aug. 18, 2022), <https://www.bakerinstitute.org/research/us-needs-lng-fight-two-front-gas-war>; see also Arvind P. Ravikumar, Morgan Bazilian & Michael E. Webber, The US Role in Securing the European Union’s Near-Term Natural Gas Supply, 7 *Nature Energy* 465 (2022), available at <https://www.nature.com/articles/s41560-022-01054-1>.

<sup>146</sup> *Id.* At 44.

<sup>147</sup> See Robert Walton, ‘Batteries Aren’t Going to Do It’: NERC’s Moura Calls for Gas Investment to Maintain Reliability, *Utility Dive* (July 21, 2022), <https://www.utilitydive.com/news/nerc-2022-reliability-report-gassolar/627784/>.

<sup>148</sup> See DOE, Valuation of Energy Security, *supra* note 5 [See U.S. Dep’t of Energy (“DOE”), Valuation of Energy Security for the United States 12 (2017), [https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20\(Full%20Report\)\\_1.pdf](https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20(Full%20Report)_1.pdf)], at 12.

decrease of approximately 24.5 percent.<sup>149</sup> From 2019 to 2020, emissions decreased by 509.7 MMT CO<sub>2e</sub>, or approximately 10.5 percent.<sup>150</sup> The commenter reports that this is due in large part to the transition to natural gas from more carbon-intensive fossil fuels, such as coal, especially in the electricity generation sector and industrial sectors.<sup>151</sup> Further, the commenter notes that the U.S. oil and natural gas production sector has maintained a much lower methane emission intensity than many of its foreign counterparts and is far superior to the intensity of many Organization of Petroleum Exporting Countries (OPEC) nations.<sup>152</sup> Thus, the domestic oil and natural gas industry already plays an important role in reducing America's overall carbon footprint.

The commenter (2301-US CC) states that oil and natural gas has a significant role to play in the ongoing energy transition. For example, natural gas is providing, and will continue to provide, the reliable, flexible, baseload power that enables increased deployment of intermittent renewable sources. This will remain a critical factor as renewable generators address challenges to deployment at the scale necessary to meet America's energy needs. The commenter contends that those challenges include, among others, permitting complications,<sup>153</sup> reliable access to markets in rare earth metals and critical minerals that serve as critical components for batteries, electric vehicles, solar panels, and wind turbines;<sup>154</sup> and the weather dependency of many renewable generation sources that lack reliable battery storage and deployment.<sup>155</sup> Further, petrochemicals and petroleum products are important base materials for renewable infrastructure, such as the layers of copolymers between photovoltaic solar panels<sup>156</sup> and the plastics, resins, and fiberglass in wind turbines.<sup>157</sup> Finally, given the current technological limitations and

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<sup>149</sup> See U.S. Env'tl. Prot. Agency ("EPA"), Inventory of U.S. Greenhouse Gas Emissions and Sinks, EPA 430-R-22-003, at ES-8 to ES-9, 2-11 to 2-13 (2022), <https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-main-text.pdf>.

<sup>150</sup> Id.

<sup>151</sup> See id. At ES-8 to ES-9, 2-11 to 2-13; C2ES, Climate Solutions, *supra* note 23.

<sup>152</sup> See Daniel Byers, GEI, The Best Solution to Pain at the Pump is Here in America (Aug. 17, 2021), <https://www.globalenergyinstitute.org/best-solution-pain-pump-here-america>; see also EIA, Global Methane Tracker 2022: Overview, <https://www.iea.org/reports/global-methane-tracker-2022/overview> (last visited Jan. 11, 2023).

<sup>153</sup> See Michael Wigmore, Brandon Tuck & Kelly Rondinelli, Feds May Need Power To Take State Lands For New Grid, Law360 (Oct. 20, 2021), <https://www.law360.com/articles/1432198/feds-may-needpower-to-take-state-lands-for-new-grid>; DJ Gribbin, Environmental Permitting Might Block Biden's Clean Energy Targets, Brookings Inst. (May 13, 2021); <https://www.brookings.edu/blog/theavenue/2021/05/13/environmental-permitting-might-block-bidens-clean-energy-targets/>.

<sup>154</sup> See IEA, The Role of Critical Minerals in Clean Energy Transitions: World Energy Outlook Special Report (2022), <https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions>, see also Daniel J. Cordier, U.S. Geological Survey, Rare Earths 2 (Jan. 2022), <https://www.usgs.gov/centers/national-minerals-information-center/rare-earth-statistics-and-information> (noting that China mined more than half of the total rare earths mined worldwide in 2021 and that China has more than one third of the total worldwide reserves of rare earth minerals).

<sup>155</sup> See Nat'l Oceanic and Atmospheric Admin. ("NOAA"), Atmospheric Science for Renewable Energy Challenges, <https://www.esrl.noaa.gov/gsd/renewable/challenges.html> (last visited Feb. 6, 2023) (discussing weather forecasting technologies that must be optimized and developed to help forecast renewable energy generation).

<sup>156</sup> See Am. Fuel and Petrochemical Mfrs., Renewable Energies Rely on Petrochemicals from Oil and Natural Gas (Mar. 4, 2019), <https://www.afpm.org/newsroom/blog/renewable-energies-rely-petrochemicals-oil-and-natural-gas>.

<sup>157</sup> See Leon Mishnaevsky, Jr. et al., Materials for Wind Turbine Blades: An Overview, 10 Materials 1285 (2017), <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC5706232/pdf/materials-10-01285.pdf>; Christopher Mone et al., Nat'l Renewable Energy Lab'y, 2015 Cost of Wind Energy Review 65 (2017), <https://www.nrel.gov/docs/fy17osti/66861.pdf>.

ongoing deployment of presently scarce grid-scale batteries, generators that combust fossil fuels will be necessary to ensure sufficient “capacity”—the capability of the generators linked to a grid to produce energy on demand—to prevent brownouts or, worse, blackouts. Natural gas-fired power plants are often the “peaking plants,” or “peakers,” that can run on demand and provide capacity during periods of high demand.

Commenter (2248-NDPC) states that the oil and natural gas industry is an integral part of the U.S. and North Dakota’s economies. In 2021, oil and natural gas accounted for 68 percent of the energy consumption in the U.S..<sup>158</sup> The commenter contends that affordable energy prices generally benefit all sectors of the American public, and cost-effective regulation of the energy industry can benefit human health and the environment.

Commenter (2166-ODNR) contends that the supplemental notice will result in the removal of a large amount of oil and gas from the marketplace, increasing energy costs to the public. The commenter notes that the supplemental notice addresses the cost of implementation, and the costs/benefits to society from reducing emissions. These costs focus on the “social costs”; however, the commenter states that the supplemental notice does not account for increased costs for alternate sources of energy due to loss of natural gas production if the wells are plugged rather than implementing emission control equipment.

Commenter (2466-IPAA) states that as natural gas has become more of an internationally traded commodity – one that has critical implications today in Europe due to the Russian invasion of Ukraine – loss of American natural gas in the world market can disrupt its stability both nationally and internationally.

Commenter (2254-PBPA) asserts that the proposed rules will reduce the total production of oil and gas in the US over the coming decades. The commenter notes that an EPA internal analysis concluded this rule would cause a loss of at least 200 million barrels of oil (equal to 28 percent of the US strategic petroleum reserve’s capacity) over the evaluated time frame. Concurrently, the EPA also reportedly underestimated the likely reduction in oil and gas production. The commenter states that hydrocarbon use in society has undeniably led to significant improvements in human life and the standard of living. Examples from the past 200 years include the world’s population increasing by seven billion, life expectancy more than doubling, and global extreme poverty levels falling from 50 percent to 10 percent. The commenter notes that human life has flourished as hydrocarbon use has increased. The commenter believes that it is a wasted opportunity to dismiss the benefits of hydrocarbon production in the US and internationally (the climate standard the EPA has chosen to use).

Commenter (2308-NSWA) asserts that the regulation will increase emissions globally due to reduced domestic production as it is curtailed -- or in some places shuttered. The commenter believes that such action will result in increased imports of oil and natural gas from producing countries with lower environmental and labor standards (i.e., India, China, Russia). The commenter contends that destabilizing national security implications of such a shift are obvious.

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<sup>158</sup> U.S. EIA.

The commenters (2308-NSWA) urge EPA to undertake a robust analysis, made publicly available prior to the implementation of the rule, to determine whether the result of the rule will be to raise production – and thereby emissions – in other producing countries and regions around the world to meet what will continue to be growing U.S. and global demand. The commenters believe that this analysis should by no means be limited to oil and natural gas, as numerous industrial processes and manufacturing have been exported overseas; however, as the EPA is contemplating new regulations on domestic oil and natural gas production, the commenters urge the analysis to begin there.

Commenter (2202-TOGA) notes that EPA recognizes the potential for additional extraction of foreign oil and natural gas, which is not produced as efficiently or effectively as the same domestically. The commenter states that the RIA's for both the November 2021 and December 2022 proposed rules detail the significant adverse effects on energy supply. Further, the commenter asserts that the maximum projected annual decreases in oil and natural gas production exceeds the OMB benchmarks - reductions in crude oil supply, in excess of 20 million barrels per year and natural gas production in excess of 40 million mcf per year - for adverse effects. Therefore, the commenter contends that the proposed rule will show an adverse impact on the supply of oil and natural gas including diminished supply, increased costs.

Response II-20-27: EPA disagrees with commenters' assertions that the regulation would have profound impacts on domestic oil and natural gas production. Several commenters assert severe impacts but fail to provide specific information to support those claims. EPA models the impact of the rule on oil and natural gas supply as a result of the Final Rule in Section 4.1 of the Final RIA EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively.

With respect to comments regarding household energy burden, EPA notes the analysis presented in Section 4.3.6 of the Final RIA and reiterates that it estimates the commodity price impacts of the final rule to be small. Finally, with respect to comments on the impact on GHG emissions of changes in oil imports, EPA is unable to quantify the impact due to data limitations. However, the relatively small estimated increase in imports suggests that the net effect on GHG emissions will be negligible.

Comment: Commenter (2218-TCEQ/RRC) states that the RIA demonstrates that significantly curtailing natural gas from the U.S. (and increasingly foreign) energy portfolio to achieve a stable climate is a major policy question that the FCAA is ill-suited to address. ("[T]he maximum projected decrease in natural gas production exceeds the benchmark for adverse effects, so this analysis indicates the proposed NSPS OOOOb and EG OOOOc constitutes a significant energy action (as defined by EO 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use)." (Regulatory Impact Analysis, EPA-452/R-21-003, p. 4-8, October 2021.)

The commenter (2218-TCEQ/RRC) provides that the electric generation from U.S. produced natural gas is a growing segment of the electric energy market both domestically and abroad as



coal powered fleets are retired and natural gas demand in Europe and Asia continues to grow. The commenter contends that Congress did not intend for the Act to drive such a significant change in the development of domestic energy supply that will have global scale impacts. (“Under our precedents, this is a major questions case. In arguing that FCAA §111(d) empowers it to substantially restructure the American energy market, EPA ‘claim[ed] to discover in a long-extant statute an unheralded power’ representing a ‘transformative expansion in [its] regulatory authority.’ *West Virginia v. EPA*, 142 S.Ct. 2587, 2610 (2022) citing *UARG v. EPA*, 134 S.Ct. 2427 (2014)). The commenter notes that the FCAA is intended to address and mitigate a real and significant threat to human health and the environment through regulation of domestic emissions. Agencies have only the authority granted to them by Congress and no such grant to address global climate change or transform international energy supply exists in the CAA. The commenter suggests that, in the RIA, using a metric for cost avoidance that is extremely speculative to weigh against the cost of regulation, and the cost to global natural gas supply, indicates the FCAA’s inadequacy for addressing climate change. “The RIA focuses on the elements of this proposal that are likely to result in quantifiable cost or emission changes compared to a baseline without the proposal that incorporates changes to regulatory requirements induced by the Congressional Review Act (CRA) resolution. We estimated the cost, emissions, and benefit impacts for the 2023-2035 period.” 87 FR 74712.

Response II-20-28: The Final Rule is readily distinguishable from the Clean Power Plan and thus, under *West Virginia v. EPA*, 142 S.Ct. 2587 (2022), does not present a major question. *West Virginia* made clear that the application of the major questions doctrine is limited to “certain extraordinary cases.” *Id.* at 2609. The Clean Power Plan was such a case primarily because there, the EPA determined the best system of emission reduction to be directly shifting generation from certain types of electricity generating plants to other types of electricity generating plants. *Id.* at 2610-11. The Supreme Court contrasted the Clean Power Plan’s generation-shifting control measure with “the sort of ‘systems of emission reduction’ [the EPA] had always before selected— ‘efficiency improvements, fuel-switching,’ and ‘add-on controls’—as ‘more traditional air pollution control measures.’” *Id.* at 2611 (quoting the Clean Power Plan, 80 Fed. Reg. 64784). The Court recognized that such “traditional air pollution control measures” “may end up causing an incidental loss of ... market share [of the regulated sources],” but emphasized that there is “an obvious difference” between issuing that type of rule and issuing a rule like the Clean Power Plan, *id.* at 2613 n.4, and in that way, the Court indicated that the “incidental” impacts of “traditional air pollution control measures” would not mean that such a measure would rise to the level of an “extraordinary case[]” that would raise a major question. The Court also noted as another reason why the Clean Power Plan raised a major question was that its generation-shifting control measure took the form of a cap-and-trade program, which Congress had “considered and rejected multiple times.” *Id.* at 2614 (citations omitted).

This rule is readily distinguishable from the Clean Power Plan. It is based on “traditional air pollution control measures,” and those control measures are not designed to shift production from one type of source to another. Any such shifts are “incidental” impacts from the “traditional ... measures.” The EPA has long applied such at the source measures stationary sources under CAA Section 111. *See, e.g.*, “Phosphate Fertilizer Plants; Final Guideline Document Availability,” 42 FR 12022 (March 1, 1977); “Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,” 42 FR 55796 (October 18, 1977); “Kraft

Pulp Mills, Notice of Availability of Final Guideline Document,” 44 FR 29828 (May 22, 1979); “Primary Aluminum Plants; Availability of Final Guideline Document,” 45 FR 26294 (April 17, 1980); “Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills,” 81 FR 59276 (August 29, 2016). In addition, EPA does not believe that the final NSPS OOOOb and EG OOOOc will transform the domestic energy supply or transform international energy supply. Rather, any impacts on oil and gas production from this final rule are marginal, on the order of one percent.

Moreover, has Congress not “considered and rejected multiple times” these control measures. On the contrary, in June 2023, when Congress adopted the Congressional Review Act joint resolution to disapprove the 2020 Policy Rule, it made clear that it expected the EPA to regulate methane emissions from new and existing sources in the oil and gas source category. See H.R. Rep. No. 117–64, 3-5 (2021) (Report by the House Committee on Energy and Commerce concerning H.J. Res. 34, to disapprove the 2020 Policy Rule) (stated that the oil and gas source category “is the largest industrial emitter of methane in the U.S.,” and that “regulation of emissions from new and existing oil and gas sources, including those located in the production, processing, and transmission and storage segments, is necessary to protect human health and welfare, including through combatting climate change, and to promote environmental justice.”); 167 Cong. Rec. S2282 (April 28, 2021) (statement by Sen. Heinrich) (Senate floor statement from Senate sponsors of H.J. Res. 34 stated that “methane is a leading contributing cause of climate change,” whose “emissions come from all segments of the Oil and Gas Industry,” and that “we encourage EPA to strengthen the standards we reinstate and aggressively regulate methane and other pollution emissions from new, modified, and existing sources throughout the production, processing, transmission and storage segments of the Oil and Gas Industry under section 111 of the CAA.”).

Comment: Commenter (2227-WEA) noted that, in a 2017 study the Enhanced Oil Recovery Institute (EORI) at the University of Wyoming examined costs of using electricity in upstream oil and natural gas.<sup>159</sup> The 2017 EORI study evaluated whether, as a result of expanding use of distributed generation, utility provided power was a low-cost option for new oil and natural gas development. The study concluded that the cost of electricity in their Wyoming study area ranged from \$7 to \$18 per barrel of oil and as a result marginal wells were being shut in. The commenter states that shutting in wells will result in production decreases, lost revenue for governments and other public entities dependent upon taxes and fees and lost revenue for the utility, all of which will subsequently detrimentally affect the local economy. The commenter suggests that it is not clear that EPA has fully considered such regional-specific challenges in the lower 48 states in the development of the proposed rules, but such challenges need to be considered on a regional basis, just as they were for Alaska. The commenter contends that expanding the electric grid in many parts of the region is particularly challenging given the economic, geographic, public land, and weather challenges that exist and provides the following recommendations:

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<sup>159</sup> “Oilfield Electrification: Collaboration Between Producers and Utilities Can Result in a Win-Win,” Omar Urquidez, Burns & McDonnell, 2021.

- Supplement the RIA to more thoroughly account for the regional developmental and implementation challenges associated with electrification of oil and natural gas operations.
- In the supplemental RIA make better use of information on the regional difficulties in implementing electric power to replace pneumatic power.
- More thoroughly document how the significant climate, geographic, topographic, and existing power grid obstacles are to be overcome to have a reliable alternative to electricity that can be developed and operated in an economically viable and operationally dependable manner.
- The proposed NSPS OOOOb and EG OOOOc regulations should be modified to take into full consideration the obvious regional electricity factors that would result from a more comprehensive supplemental RIA.
- EPA should supplement the RIA to more thoroughly examine the availability, functionality, economics and reliability of using electricity as a key resource in eliminating pneumatic controller emissions.
- EPA needs to take a more exhaustive look at lower 48 states' regional challenges associated with the power grid pertaining to obstacles such as climate, permitting, environmental, geography, and topography, accommodating for such factors as was done for Alaska.

Response II-20-29: EPA disagrees with the commenter's assessment that the RIA needs to assess regional implementation challenges associated with the electrification of oil and natural gas operations. While the RIA attempts to model important region-specific factors where possible (e.g., in the assignment of region-level major equipment distributions to model well sites), its primary purpose is to provide a best-estimate assessment of the nationwide impacts of the rule. Due to data limitations, EPA cannot feasibly account for local conditions across the country, and the commenter does not provide the necessary data to address these limitations.

With respect to the 2017 EORI study, the cost of electricity cited by the commenter is for bringing grid-based line power to the site, which is not a requirement of the rule. When assessing the possibility of using a generator to supply power, an option permitted under the rule, the study authors find that option to be less expensive in most cases. In addition, the study authors do not model the possibility of using solar photovoltaic systems with battery storage, which EPA finds to be an even more cost-effective option than a natural gas-powered generator in many cases.

The EPA considered these and other comments regarding regional differences and access to electricity when developing the final requirements under the final NSPS OOOOb and EG OOOOc rules. For example, as discussed in a response to a comment related to access to electricity for process controllers in Volume II, Chapter 7 (Process Controllers), subsection 7.2.2 (Access to Reliable Electricity), Response II-27-7, although the final rule maintains that sources outside of Alaska must meet the zero emission standard, there are several options available to such sites to meet the NSPS and EG. These include the use of solar-powered process controllers, the use of electric process controllers powered by a generator, the use of compressed air-driven process controllers powered by a generator, and routing emissions to a process. The EPA also notes that solar-powered process controller systems include batteries that are typically sized to contain a 10-day power supply, and this battery power ensures continuous process controller

operations. This would also apply for pumps (see Volume II, Chapter 8 (Pumps), subsection 8.2.2 (Access to Electricity), Response II-8-17).

Comment: Commenter (2219-WOGCC) In evaluating the economic impacts, EPA utilizes the social cost of carbon, methane, and nitrous oxide among other asserted social benefits. These societal benefit values are necessary to justify a rule that in reality costs more to comply with than it ends up benefitting. What is left out of the economic analysis are costs to society that will result from the implementation of the proposed rule. Not only will society lose the benefits of royalties, taxes, and jobs that are lost when wells are prematurely shut in and plugged, society will lose by incurring increased prices for fueling their vehicles, heating their homes, food or other goods, and all other items that society uses on a daily basis that are impacted by increased fossil fuel prices. The premature shut in and plugging of wells can only result in two outcomes. Either oil and gas prices will increase due to elimination of a portion of the supply or the loss in supply will be made up in other places. In either scenario society loses. Society loses by paying higher costs or it loses because of the environmental impact of shifting production to nations that do not produce oil/gas as cleanly and efficiently as the U.S. and incurs further environmental impacts by transporting that oil/gas to the U.S. In particular, the people of Wyoming lose. The costs of methane reduction in this rule are disproportionately born by the people of Wyoming and other oil and gas producing states. If EPA is utilizing societal benefits in justifying the economic impact of this rule it should also use the societal costs and conduct a full and complete economic analysis and consider localized impacts.

Response II-20-30: With respect to the comments regarding premature shut in and plugging of wells, EPA notes that it developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. In any case, the analysis suggests that to the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells, and so the impacts on overall production and royalties would be minimal.

Comment: Commenter (2353-CrownQuest Operating, LLC.) states current monthly report estimates of recordkeeping for this proposed rule is over 880,000 hours per year for NSPS OOOOb and 2.2 million hours for EG OOOOc, with an estimated cost of over \$224 million annually for the industry, which is a significant underestimation. There are over 500,000 facilities between NSPS OOOOb and EG OOOOc that the EPA estimates to be covered by this rule. The commenter states all the estimated reporting applied to fugitive emissions facility annual reports would equate to about 6 hours per year. It is likely to be much more intensive than the estimated hours of recordkeeping, especially by smaller operators and small businesses that make up a large portion of the EG OOOOc facilities. This rule is complex and forces a diverse group of operations and sites into a one-size-fits-all box for a national agency to manage, which is ineffective regulation. This rule makes a critical, widely divergent, dispersed industry ask permission before operating. It will devastate oil and gas production, especially the future development of new oil and gas reservoirs.

Commenter (2353-CrownQuest Operating, LLC.) argues the EPA should instead focus on the recordkeeping that has shown to be effective based on critical operations. Making gathering and reporting on multiple types of data mandatory will create more data than can be analyzed or useful. For example, the EPA collected data from NSPS OOOOa for over 12 years but does not cite this data or its effect on targeted facilities' emissions once in the entire rule. This proposed rule is a massive expansion of NSPS OOOOa's requirements, especially regarding recordkeeping.

Commenter (2353-CrownQuest) states that there is no doubt that these proposed rules will reduce the total production of oil and gas in the U.S. over the coming decades. An EPA internal analysis concluded this rule would cause a loss of at least 200 million barrels of oil (equal to 28% of the US strategic petroleum reserve's capacity) over the evaluated time frame. Concurrently, the commenter adds that the EPA also reportedly underestimated the likely reduction in oil and gas production.

The commenter (2353-CrownQuest) notes that hydrocarbon use in society has undeniably led to significant improvements in human life and the standard of living. Examples from the past 200 years include the world's population increasing by seven billion, life expectancy more than doubling, and extreme poverty levels falling from 50% to 10%. Human life has flourished as hydrocarbon use has increased. The commenter suggests that it is a wasted opportunity to dismiss the benefits of hydrocarbon production in the U.S. and internationally (the climate standard the EPA has chosen to use).

The commenter (2353-CrownQuest) provides that the EPA states, "this rule will save enough gas to heat 3.5 million homes in the winter". According to the commenter, this statement points out the EPA's biased analysis and skewed calculations. The RIA calculates the rule will save 2,037 BCF of CH<sub>4</sub> from 2023 to 2035 but also cause the loss of 2,825 BCF of natural gas. The commenter suggests that a more appropriate statement by the EPA would be, "this rule will reduce the gas supply and leave 1.4 million homes without fuel in the winter". The commenter adds that this rule shows the EPA has a fundamental lack of understanding of the impact of these rules and the benefits of hydrocarbon access, especially for the poorest people.

Response II-20-31: The recordkeeping and reporting requirements in the rule that apply for each affected/designated facility represent the minimum level of tracking and documentation necessary to ensure compliance with the rule. EPA emphasizes that recordkeeping and reporting are vital components of compliance assurance and believes the recordkeeping and reporting requirements established in the final rule are reasonable and appropriate.

The EPA spent a significant effort in finalizing the specific cost elements used to estimate the recordkeeping and reporting burden when preparing estimates for the 2020 NSPS OOOOa rulemaking in order to address multiple comments received that the EPA had significantly underestimated the time and cost to complete the recordkeeping and reporting requirements (especially associated with the fugitive emissions program) under NSPS OOOOa. The majority of these costs and assumptions were retained in the recordkeeping and reporting burden analyses included in the December 2022 Supplemental Proposal and the final rule estimates, including the assumption of 22 wellsites per company-defined area and for gathering and boosting compressor

stations 7 stations per company defined area. See section VII.B (Paperwork Reduction Act (PRA)) of the final rule preamble for EPA's estimate of the recordkeeping and reporting requirements under NSPS OOOOa, NSPS OOOOb, and EG OOOOc.

The commenter provides no data or analysis to support the assertion that "EPA also reportedly underestimated the likely reduction in oil and gas production."

Comment: Commenter (2241-UDNR) contends that, while the U.S. could be taking a positive role in the international gas supply situation as a result of the Ukraine war by "opening the valve" on U.S. supplies and sending that liquid natural gas (LNG) to our North Atlantic Treaty Organization (NATO) allies in Europe, instead, natural gas production in the U.S. is down due to the anti-fossil fuel policies of the current administration, which have made investors hesitant to invest in natural gas projects.<sup>160</sup> For example, the commenter notes that, as of December 19, 2022 natural gas production in Utah is 194,602,919 thousand cubic feet (MCF), which is the lowest level of production in Utah since 1984.<sup>161</sup> For comparison, the commenter notes that the highest level of natural gas production in Utah came in 2012 with 490,575,308 MCF produced. While Europe continues to slog through the natural gas shortage quagmire, here in the U.S. through regulatory burden we are hamstringing our own operators and contributing to the artificial shortage which not only harms our economy at home, but hurts our allies overseas. From a purely economic standpoint, the commenter suggests that it would make sense to take advantage of this opportunity to bolster the U.S. economy. From an international relations standpoint, it makes sense to export the LNG we have in abundance here in the U.S. to our foreign allies, strengthening them in the uncertain geopolitical world we all live in, and strengthening our own economic and political position in the process.

As such, the commenter (2241-UDNR) believes that adding to necessary infrastructure (such as by building an LNG export facility somewhere on the west coast) would provide a better market for Intermountain West natural gas, help supply LNG to other countries and reduce their reliance on coal in the process. One such port was proposed at Coos Bay, Oregon, namely the Jordan Cove project. However, the project never saw completion as environmental activists and other groups successfully fought the project and the associated pipeline.<sup>162</sup> Due to such opposition, natural gas producing states (such as Utah) are having to look to other areas along the Pacific Rim as options for exporting their natural gas and getting it to market. For example, Utah is looking outside the U.S. to Mexico in an effort to access a "replacement port" for its goods. The port (with LNG export capabilities), is located in Ensenada, Mexico and is slated for completion in 2024.<sup>163</sup> While this port has the potential to provide the much needed potential export facilities

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<sup>160</sup> Myra P. Saefong, EIA reports a weekly decline in U.S. natural-gas supplies smaller than the 5-year average, MarketWatch, available at: <https://www.marketwatch.com/story/eia-reports-a-weekly-decline-in-u-s-natural-gas-supplies-smaller-than-the-5-year-average-01671118892?siteid=yhoof2&yptr=yahoo> (2022).

<sup>161</sup> Utah DNR, Gas Production Per Year (past 5 years), Utah Department of Natural Resources; Oil, Gas & Mining, available at: <https://oilgas.utah.gov/gasProdVolPerYear.php> (2022).

<sup>162</sup> Andrew Selsky, Controversial plan for Jordan Cove natural gas terminal in Southern Oregon abandoned, Associated Press, available at: <https://www.registerguard.com/story/news/environment/2021/12/01/jordan-cove-natural-gas-terminal-abandoned-southern-oregon-lng/8830677002/> (2021).

<sup>163</sup> SEMPRA, ECA LNG – A World-Class Project to help Power the Global Energy Transition, Semptra Infrastructure, available at: <https://semprainfrastructure.com/news-and-events/spotlight-stories/eca-lng-a-world-class-project-to-help-power-the-global-energy-transition> (2022).

for Utah and other Intermountain States, it is the State's recommendation that similar projects be encouraged here in our own nation, so that our producers can get their product from the oil patch to international markets without having to take unnecessary additional steps by first exporting the product to Mexico.

In sum, the commenter (2241-UDNR) notes that Europe and the rest of the world is facing a natural gas shortage. Exporting the abundant gas here in the U.S. would alleviate the pressures faced in Europe, while simultaneously reducing global coal reliance. However, they suggest that U.S. policies and environmental regulations are hampering our collective ability to produce and export more LNG, exactly in the moment when the world stage needs it most. As such, it is their recommendation that the EPA look at ways to encourage production – not restrict it through overburdensome regulations.

Response II-20-32: EPA disagrees with commenter's assertion that the rule will significantly inhibit oil and natural gas production. EPA models the impact of the rule on oil and natural gas supply as a result of the Final Rule in Section 4.1 of the Final RIA. EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively.

#### ***20.4.4 Labor Availability Issues***

Comment: Commenters (2223-Texas Alliance of Energy Producers, 2283-Endeavor Energy, 2241-UDNR, 2305-Williams) express concern with labor shortages impacting the ability to meet requirements.

Commenter (2223-Texas Alliance of Energy Producers) notes the EPA has indicated in-house training and specialization on this is the best way to control cost, but that option is not always available to small businesses. The prospect for contract or outsourcing this requirement would place undue burden on small operators and cost estimates should reflect regional variability and rural workforce considerations that will show dramatic differences in price per service. Many of the commenter's members have made clear that they lack the adequate staff and resources to meet this new requirement should it be implemented for all facilities.

Commenter (2305-Williams) states that, in addition to increased equipment demand, there will also be an increased demand on specialized skill workers that could add further delays. If the EPA expects facilities to modify existing control devices to accommodate both new and existing sources, they suggest EPA allow more time for compliance. Installing new flow meters, testing ports, or net heating value measurement tools on existing control device lines handling multiple units or sources involves "hot tap" safety protocols. The commenter reports that this is specialized work that is typically handled by only a small handful of qualified contractors. In-house staff typically do not perform hot tap work. Therefore, for example, if EPA expects an entire industry to modify existing flares, the compliance deadline must account for the relatively small labor pool available to perform that work.

Commenter (2283-Endeavor Energy) contends that the manpower required to convert over all of the existing well sites across the Midland Basin to comply with the EGs as proposed is not available. The commenter notes that the region currently has a 2 percent unemployment rate. The commenter estimates that it would take an average work crew of four men about two weeks to make the conversions necessary for the average existing well site in the Midland Basin to come into compliance with proposed EG OOOOc. In order to meet just the needs of their operations, the commenter estimates it would take 320 qualified workers working full time for a year.

Based on their experience, the commenter (2283-Endeavor Energy) does not believe there are a sufficient number of contractors who can meet the needs of all operators in the Midland Basin, and "scaling up" too quickly would pose risks if contractors are forced to rely on new personnel who do not have qualifications, training, and experience to perform the necessary upgrades. This is just one example of why they believe the EPA cannot and should not assume that just because requirements have proven to be feasible for the much smaller pool of new or modified sources that operators are also able to implement these requirements more broadly for their existing sources.

Commenter (2241-UDNR) notes that recent data released by the U.S. Bureau of Labor Statistics shows that of the eight major industry sectors in America, five of them have recovered and now exceed pre-pandemic employment levels, while three of those sectors have yet to recover.<sup>164</sup>

The commenter (2241-UDNR) notes that the figure provided in their comment letter shows, of the three sectors that have not yet recovered, one of them is the "Mining and Logging sector." [Figure provided in comment letter: Timeseries graph from Feb 2020-Dec 2022, showing the change in employment level in various industry sectors (construction, government, retail trade, education, etc.)] The commenter adds that this particular sector includes several smaller sectors, namely agriculture, forestry, fishing, hunting, mining, quarrying, and oil and gas extraction.<sup>165</sup> The commenter provides that while the oil and gas extraction industry is not directly accounted for individually on the table, it is included in the overall "Mining and Logging" sector, which as shown, is still struggling to recover to pre-COVID employment levels.

At a time when the entire oil & gas industry (as well as the mining and logging sector as a whole) is struggling to recover from the last few years of economic slowdown and employment shortages, the commenter (2241-UDNR) believes that EPA should help the industry recover – not stifle it while it's struggling.

Response II-20-33: The EPA considered these and other comments expressing concern over labor availability issues when developing the final rule requirements for NSPS OOOOb and EG OOOOc.

For the NSPS OOOOb, the EPA has concluded that only sources constructed, modified, or reconstructed after the date of the Supplemental Proposal (December 6, 2022) should be

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<sup>164</sup> 4 U.S. Department of Labor, Bureau of Labor Statistics: Employment Situation Summary, January 6, 2023 (Table B-1).

<sup>165</sup> 5 USBLS, Industries at a Glance: Natural Resources and Mining, U.S. Bureau of Labor Statistics, available at: <https://www.bls.gov/iag/tgs/iag10.htm> (2023).



considered new sources for the purposes of NSPS OOOOb. Changing this date to December 6, 2022, from the November 15, 2021, reduces the number of existing new sources that will need to comply with NSPS OOOOb, thereby allowing more time to address labor availability concerns. For details, please see discussion in section IX (Interaction of the Rules and Response to Significant Comments Thereon), subsection A (What date defines a new, modified, or reconstructed source for purposes of the final NSPS OOOOb?) of the final rule preamble. The EPA has also provided an alternative compliance timeline in the NSPS OOOOb final rule for process controllers and pumps required to meet a zero-emission standard (*i.e.*, final rule allows up to one year from the publication date of the final rule). See section XI.D.4 (Compliance dates) of the final rule preamble for a discussion on the compliance dates finalized for process controllers (which also applies for pumps).

For the EG OOOOc, the EPA is finalizing a compliance timeline of 36 months from the deadline for state plan submittals, which provides owners and operators of designated facilities time to plan and meet any increased labor demands. When the compliance timeline of 36 months is considered in conjunction with the state plan submittal deadline of 24 months, that means that sources could have up to 5 years between when the EG are final and when they are required to fully comply with the applicable standards of performance. The EPA believes that any concerns with possible equipment or staffing shortages, which commenters speculate could be an issue, would likely be addressed by industry and regulators in that timeframe. See section XIII.E.3 (Compliance timelines) of the final rule preamble for EPA's response to comments regarding the compliance timeline required under the EG.

#### ***20.4.5 Small Business Considerations***

Comment: Several commenters (2187-WB Osborn, 2200-NuEnergy, 2205-Kriebel, 2220-WDEQ, 2223-TAEP, 2238-SOOGA, 2241-UDNR, 2248-NDPC, 2254-PBPA, 2257-MOGA, 2279-SBA, 2294-OOGA, 2314-Miller Energy, 2322-AR DEQ, 2403-PAO, 2446-IPAA, 2625-Fore Energy, 2696-Peters et al, 3845-ND Congress) note that impacts of the proposed rule will disproportionately impact small businesses and request EPA give special consideration to the small business impacts of the rule. Some of the specific comments provided are included in the following paragraphs.

Commenter (2322-AR DEQ) asserts that the Proposed Rule, if finalized, represents a substantial expansion in the scope of sources regulated under their agency's air pollution control program; is anticipated to have major economic impacts for the state, particularly for small business operators and property owners who currently have financial interests in oil and gas operations.

Commenter (2322-AR DEQ) goes further, with the addition of thousands of new qualifying sources performing quarterly OGI, and without consideration of additional testing required for larger sources, the commenter anticipates a considerable increase in emission testing observations per year under the Proposed Rule. Increases in testing would stretch agency staff and resources thin. This would likewise be compounded by the fact that the rural nature of these locations will create substantial travel times between sites. Significantly increasing the number of additional sources to permit and inspect creates the need for additional permitting staff to process the onboarding of so many new sources and for additional enforcement staff when

noncompliance with requirements is noted. Though many sources could likely qualify for a general permit, there would still be a need for additional permit engineers and supporting administrative staff dedicated to oil and gas permit processing as well as customer service, due to the sheer volume of new sources.

Commenter (2322-AR DEQ) believes a regulation, rule, or requirement is only as effective as the compliance strategies and enforcement actions that actually govern it. Without a viable method for checking to ensure that all requirements are being met by all sources subject to the Proposed Rule, there is a potential to create an uneven economic advantage for those who choose to ignore the regulatory requirements. For some, it could be viewed as less burdensome to pay a penalty on the rare chance noncompliance is discovered than it is to comply.

Commenter (2446-IPAA) contends that the proposed regulations negatively impact low production wells. The commenter notes that most of the wells are operated by small businesses that are not able to distribute the additional compliance cost across many wells or high volume of production. The commenter states that these regulations disproportionately impact small businesses in every oil producing state, and the service companies that support the operators. Most of the small operators do not have the technical resources to be able understand EPA's requirements and implement the required programs. The commenter states that EPA will need to provide resources to assist the small businesses with compliance.

Commenter (2223-TAEP) contends that small operators —the vast majority in Texas and across the nation -- stand to be exponentially more affected by the implementation of “one-size-fits-all” approach of the proposed rule. The commenter notes for example, many of those small operators operate actively producing wells in the U.S. that produce 15 barrels of oil equivalent/90 MCF of gas or less per day. The commenter expresses concern that the proposed rule – for reasons detailed in the producers association comments -- will result in making those wells uneconomic, likely leading to shuttering, simply as a result of its implementation. The commenter states that any rule that imposes a cost on the operator would clearly disadvantage smaller operators relative to larger operators, and adversely impact communities across Texas that rely on small businesses. The commenter contends that no rule adopted by EPA should have the effect of putting oil and gas companies of any size out of business, or significantly changing the economics of the operations.

The commenter (2223-TAEP) urges EPA to continue to work closely with the Small Business Administration (SBA) to minimize and streamline regulatory requirements and burdens stemming from the rule. The commenter notes that their members and others continue to proactively address and reduce methane emissions from our operations and related work. Examples include:

- Texas Methane and Flaring Coalition, a coalition of trade groups and companies, including oil and gas operators of all sizes, established to track methane and flaring data in Texas and consider a group of industry best practices to monitor and reduce emissions in ways that do not impose economic harm on Texas producers.
- Modern production techniques, like hydraulic fracking, have brought substantial environmental benefits to the U.S. The dramatic decrease in carbon dioxide emissions is

due to fracking and the increased production and use of natural gas in the electricity sector.

- According to the state's oil and gas regulator, the "Railroad Commission production data shows that the percentage of natural gas flared compared to the natural gas produced from oil and gas wells in Texas dropped from a high of 2.29 percent in June 2019 to 0.65 percent in May 2021. During the same period, the volume of gas flared decreased by approximately 73 percent."<sup>166</sup>

Commenter (2187-WB Osborn) contends that the proposed regulations are so voluminous and complex that they, as a company with less than 20 employees, have not had time or resources to fully assess the impacts of these proposed rules and their impact to their business. The commenter asserts that it is unfair that small oil and gas operators are forced to allocate their limited resources to understanding, debating, and ultimately modifying their operations to comply with the proposed rules, if they are adopted.

The commenter (2187-WB Osborn) estimates that using their existing legal resources at \$750.00/hour, 120 hours of research, applicability assessment and construction of recommendations, an added cost to their operations of \$90,000/month would be required to completely understand the EPA proposed rules. The commenter reports that this expenditure is required to fairly and responsibly address the issues raised by these proposed rules to the benefit of our company and its stakeholders. The commenter notes that this amount represents a 42 percent increase in their monthly operating costs, with no additional benefit to our company.

Commenter (2205-Kriebel) expresses concern with the disconnect with understanding the differences between a large natural gas & oil producer (i.e., Shell, BP) and a small marginal natural gas & oil producer (approximately 100 employees or less). The commenter asserts that this misunderstanding appears to have led to an excessive NSPS proposal that imposes a strong cost burden on the marginal well producer.

Commenter (2200-NuEnergy) contends that the rules discriminate against small businesses and make fair competition in a free-market economy unattainable. The commenter notes that the proposed rules are designed to be one size fits all which does not make sense when comparing emissions from a large production well to a marginal well. The commenter states that the economics of compliance and the emissions reductions will be drastically different, yet the proposed rules seem to ignore that fact. The commenter adds that in their brief review of the proposed EPA regulations, it appears that they potentially conflict with the State of Michigan's Office of Oil, Gas and Mineral (OOGM) rules and regulations. It appears that the premature plugging and abandoning of otherwise currently profitable marginal wells affect the OOGM's directive to prevent waste in the State of Michigan. The commenter notes that this is bad for Michigan and small businesses.

Commenter (2403-PAO) states that many small oil and gas businesses will be negatively impacted. The commenter requests that EPA recognize the importance and benefits of marginal wells to the U.S., the State of Oklahoma, small businesses, and rural environmental justice

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<sup>166</sup> <https://www.rrc.texas.gov/news/072821-flaring-trends/>.

communities that depend on the oil and gas industry, in its rulemaking process. The commenter contends that the RIA does not address how a well(s) producing an average of 1.43 barrels per day (Bpd) and/or 18 Mcfpd can be economically viable under the new multiple source requirements. The commenter asserts that the Proposed Rule will impact existing wells, especially low producing, marginal oil and gas wells that provide the state with direct revenue in the form of royalties, taxes, and indirect economic benefits through employment and other economy-enhancing activity.

The commenter (2403-PAO) notes that tax code provisions define a low producing well as one producing 15 Bpd of oil equivalent or less. The Interstate Oil and Gas Compact Commission (IOGCC) defines a marginal well as a well that produces 10 barrels of oil or 60 Mcf of natural gas per day or less.<sup>167</sup> In Oklahoma, there are approximately 28,000 marginal oil wells (with an average production of 1.43 Bpd) and approximately 45,000 marginal gas wells (with an average 18 thousand cubic feet per day [Mcfpd]); however they contribute approximately 9.5 percent and 12 percent, respectively, to Oklahoma's total production.<sup>168</sup> The commenter states that these types of wells are important to their members and the state's economy, and they are typically operated by small businesses. Small businesses in the Mining, Quarrying, and Oil and Gas Extraction industry in Oklahoma employ over 20,000 people, or over 50.5 percent of the private workforce employed in that sector in 2017. Additionally, the commenter states that marginal wells provide a significant share of the U.S. domestic oil and natural gas output and economic contributions. The IOGCC states that since approximately 2006, marginal wells have produced oil and natural gas valued at nearly \$30 billion annually, or approximately 10 percent of the total value of oil and natural gas produced domestically.

Commenter (2314-Miller Energy) urges EPA to consider the impact this regulation would have on small oil producers and their ability to compete with the big-industry players. The commenter states that the one-size-fits-all approach discriminates against small businesses and make fair competition in a free-market economy unattainable.

As a small business in Michigan with less than 50 employees and marginal-stripper wells, the commenter (2314-Miller Energy) states that it does not have the same resources as the big players in the industry. The commenter asserts that the proposed regulations would have a larger impact on their sustained operations than large businesses.

Commenter (2248-NDPC) contends that these burdensome and duplicative environmental regulations will cause more damage than good to the economics of North Dakota, impacting disadvantaged communities and small businesses.

The commenter (2248-NDPC) states that many of North Dakota lessees are small businesses that run wells with little room for changes that would render their wells uneconomical. Even though these wells are considered small producers, they make up a large portion of the wells in North Dakota and across the nation. The commenter asserts that the lessees will now be faced with a choice to continue their livelihood at great expense that may never be recovered or to abandon those locations. The commenter notes that the loss of this production not only impacts the energy

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<sup>167</sup> IOGCC, Marginal Wells: Fuel for Economic Growth, 2016.

<sup>168</sup> Ibid.

security of the nation, but the economic security of thousands of North Dakotans. These small producers support other small service businesses that will also be forced into uncertain economic situations. According to a 2021 economic impact study, almost 50,000 jobs in North Dakota are a result of the oil and natural gas industry with a payroll totaling \$4.5 billion dollars. The commenter states that, operating under the current regulatory oversights and requirements, families are provided with the opportunity to make a living wage and support themselves and their families.

Commenter (ND Congress-3845) provides that small oil and natural gas producers are key contributors to North Dakota's economy. In addition to paying royalties and taxes, the commenter reports that these producers create jobs for North Dakotans directly through employment and indirectly through supporting local businesses. However, small producers often have thin margins restricting their operational flexibility. The commenter states that the EPA's proposed rule would impose costly additional requirements on single wellhead sites, many of which are owned by small, independent producers. Small producers are disproportionately impacted by the proposed rule due to the high costs of equipment needed for compliance. They also face a potential lack of availability of equipment, as compared to large producers. Further, the commenter suggests that the EPA's prescriptive compliance requirements will limit operational flexibility and prevent small producers from implementing innovative new approaches. Once EPA's rule becomes effective, the commenter state that many small producers will find that their operations are now uneconomical. As a result, the commenter believes that the EPA's proposed rule will force many small producers out of business, thereby reducing royalties, taxes, and jobs within North Dakota.

Commenter (2696-Peters et al) requests that EPA include more consultation with small producers and consider the unique needs of those small and family-owned businesses. The commenter states that while many larger entities can comply with new regulations, smaller companies may struggle to adopt technologies mandated by EPA, thus further highlighting the importance of technology flexibility.

Commenter (2241-UDNR) encourages EPA to acknowledge/incorporate environmental justice, community involvement and small business impacts this rule will have. The commenter notes that many of the oil and gas sources in Utah are located in rural areas where the oil and gas industry have a large economic impact. The commenter encourages EPA to continue to support flexibility with these rules to ensure balance with economics and protection of human health and the environment. The commenter notes that there are many low- producing wells within the state and small businesses that own and operate those wells will need support and time to understand requirements, acquire and install new equipment and make necessary procedural changes. The commenter encourages EPA to allow a longer implementation time for such low producing wells.

Commenter (2254-PBPA) states that the EPA should have considered the EG OOOOc costs and impacts of the RIA on small businesses. The commenter asserts that the EPA's proposed BSERs are restrictive, limit state implementation, and significantly affect a much larger universe of small businesses. For example, Texas's (using the Railroad Commission's 2021 production data) top 22 operating entities account for 55% of Texas' production, while the smallest 2,477 entities

account for less than 1%. The commenter reports that these proposed rules will primarily impact those smaller operators. The total production from those entities was 31,055 BOPD and 99,710 MCFPD (36 BCF/year) from 29,520 leases equaling 3 MCFPD per lease. The commenter adds that the proposed regulations will have a significant adverse impact on small businesses based on the capital, operating increases, and regulatory burden; and that the proposed BSER's recordkeeping and reporting will make operating these leases uneconomic for many small businesses.

Commenter (2257-MOGA) recommends that EPA consider including past estimates on cost recovery estimates to be honored from previous rulemaking justifications and allow small businesses the opportunity to recover capital costs before making future initial investments. As proposed, the commenter states that the new regulations keep moving the standards beyond the reach of many small businesses that have diligently complied with previous rules.

The commenter (2257-MOGA) states that many small businesses subject to emissions reduction requirements outlined in NSPS OOOO and NSPS OOOOa have succeeded in reducing emissions based on their implementation of the regulations and ask why these small businesses should now be penalized for their success? The commenter recommends the EPA provide small businesses with prior documented capital investment during recent and current regulations an "Exemption Classification" from new capital investment in the proposed regulations to allow cost recovery from promised, yet unrealized returns on capital investment.

The commenter (2257-MOGA) adds that the State of Michigan views early plugging and abandonment of wells with remaining production horizons as waste. Part 615 of the state's regulatory framework stipulates the minimization of waste by efficiently managing operational endeavors to achieve maximum resource recovery. Many of Michigan's small entity producers facilitate this mandate by minimizing operational costs, negotiating production contracts, adjusting operational production schedules and minimizing all costs when available. Michigan's small entity and small business producers require flexibility to meet the State of Michigan's objective to maximize resource recovery. The commenter contends that the proposed NSPS and EG regulations would burden Michigan's small business marginal well producers with significant costs to achieve less than the maximum resource recovery, which directly contradicts the State of Michigan's laws regarding the waste of state resources.

Commenter (2257-MOGA) notes that their review of historic rule changes to the CAA found that the Act required changes in 1967, 1970, 1977 and 1990. The commenter suggests that these dates provided a large enough gap to go through the sequence of product changes and allow producing companies to recover initial capital investment before updating to a more effective device. However, recently the EPA has implemented new regulations or modifications to regulations in 2012, 2016, 2020, 2021 and now in 2023. The commenter states that each prior regulation developed cost-based estimates to include an estimated time of return based on the capture and sale of emissions. The commenter believes the EPA must explain and include discussion and their rationale for revolving standards over a short period of time compared to historical changes to the CAA.

The commenter (2257-MOGA) emphasizes that that small businesses and marginal well operators do not have the luxury of continuous capital investment for new technology. According to the commenter, during the NSPS OOOO and NSPS OOOOa rulemaking efforts, many of Michigan's small business producers spent significant capital investments in their operations without recovering the initial capital investment costs promised in the regulations. The commenter believes that the aggregate and restrictive cost burden based on revolving regulations every 2 to 4 years, without an adequate baseline to assess the effectiveness, has become excessive and is not sustainable for small businesses with limited operating budgets.

Commenter (2279-US SBA) states that the proposed rule disadvantages small businesses. The commenter recommends that EPA consider and present explicitly the impacts of its rule on all small businesses, including those that are operating existing sites. The commenter recommends that EPA consider how the disadvantages to small business affect the cost-effectiveness of its proposal and consider a range of different size categories.

The commenter (2279-US SBA) notes that calculations of cost-effectiveness rely on averages of costs across the whole industry, reflecting economies of scale for equipment and human resources that are not available to many small businesses. The commenter states that compliance timelines assume priority access to equipment and materials that are not available to small businesses. In addition, annualization over the full lifetime of equipment assumes longer-term financing that is often not available to small businesses.

Commenter (2294-OOGA) states that small businesses being forced to close presents a scenario that is inherently contrary to the Supplemental Proposal – i.e., there may be thousands more abandoned wells that may or may not be properly closed.

Response II-20-34: EPA provides small business analysis in the revised IRFA (found in Section 4.3 of the December 2022 RIA) and FRFA (found in Section 4.4 of the Final RIA). As a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule; compliance with the RFA regarding the EG OOOOc will be addressed as part of the process of developing the federal plan. Still, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart.

In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. For example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In response to comments regarding marginal wells, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding

requirements, accounting practices, and tax credits available to the oil and gas industry. Moreover, to mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s). EPA is unable to assess the viability of the owners and operators of the marginal wells, and as such, EPA is therefore unable to predict which firms will be most adversely affected by regulatory costs.

In response to comments that state that the EPA must perform small business-specific cost evaluation for all sources under the proposed rule using a more granular approach to the cost-effectiveness analysis and that unique aspects of small businesses were not considered in the development of analyses, we disagree. When conducting BSER for affected facilities/designated facilities, one aspect is to evaluate the cost of a control. As part of that evaluation, the EPA considers various associated costs, including capital costs and operating costs (and retrofit costs and challenges), including costs provided by commenters (including small businesses). While our analyses do not reflect every known scenario and equipment configuration, the EPA addresses unique circumstances presented by commenters where it is supported. As an example, see section XI.G.6 (Wet seal compressors equipped with a seal oil gas separation system utilized on the Alaska North Slope (ANS)) of the final rule preamble, where a commenter provided information to support an alternative performance-based volumetric flow rate standard for wet seal compressors equipped with a seal oil gas separation system utilized on the ANS.

As discussed in section VIII.B (How does EPA evaluate control costs in this final action?) of the final rule preamble, the final standards will impose some new costs on industry (including small businesses). Many of the standards, however, reflect control mechanisms and measures that many companies and sources around the country are already implementing – again, without deleterious effect on industry as a whole – which shows not only that such controls are “adequately demonstrated” but also underscores their reasonableness from a cost perspective. The EPA provides the cost effectiveness estimates for reducing VOC and methane emissions for various control options considered in the November 2021 Proposal and the December 2022 Supplemental Proposal, as well as in section XI of this preamble and associated TSDs. See also Volume II, Chapter 4 (Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations), section 4.3.4 (Small Business/Cost Concerns) comments and responses on small business/cost concerns related to fugitive emissions requirements.

Also, as noted above, the revised IRFA and FRFA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. In addition to providing several compliance alternatives for affected facilities under NSPS OOOOb and designated facilities under EG OOOOc, the EPA has also considered issues such as lingering supply chain issues and increased demand for equipment and



services when establishing compliance, and repair and delay of repair provisions included in the final NSPS OOOOb and EG OOOOc rules to account for parts not being available.<sup>169</sup>

Additionally, both NSPS OOOOb and EG OOOOc include provisions that could be pursued for an alternative but equivalent compliance option under NSPS OOOOb or equivalent or less stringent requirements considering remaining useful life and other factors (RULOF) under EG OOOOc under a state plan. 40 CFR 60.5399b (What are the alternative means of emission limitations for GHG and VOC emissions from well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components, and process unit equipment affected facilities; and what are the alternative fugitive emissions standards based on state, local, and tribal programs?) of NSPS OOOOb provides procedures for the submittal and approval of alternative means of emission limitation for GHG and VOC based on work practices for well completions, liquids unloading operations, centrifugal compressors, reciprocating compressors, fugitive emissions components and process unit equipment affected facilities. See section XIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for state plan requirements and sub-section XIII.C.3 (Remaining useful life and other factors (RULOF)) of the final rule preamble for a summary of the RULOF provisions that have been finalized in the subpart Ba rulemaking (codified at 40 CFR part 60, subpart Ba).

For other comments arguing that EPA's one-size fits all approach does not adequately address the variability across the industry and EPA's responses, see Volume I, Chapter 23 (Miscellaneous Other Comments), section 23.17 (One-Size Fits All Approach) of this RTC document.

Comment: Commenter (2257-MOGA) believes the EPA has not considered or incorporated comments and concerns regarding the technical and financial infeasibility resulting from limited and condensed interactions with the small business segment of the oil and gas production industry before proposing new regulations. The commenter states that they participated as a small entity representative (SER) on the SBAR Panel Process required under the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA). These online Zoom meetings were hosted by the SBA and the EPA on June 29, 2021, July 29th, 2021, and August 3, 2021.

The commenter (2257-MOGA) reiterates several of their comments submitted to the EPA on August 12, 2021, to highlight their concern with what they believe is the EPA's lack of consideration and incorporation of SER's concerns and comments prior to the publication of the current proposed regulations:

- The commenter is concerned with the EPA's apparent lack of knowledge, specious characterization and generalization of the oil and gas production environment. Major production equipment is not fragile. Vessels, tanks, lines, wellheads, etc. were designed to withstand the elevated pressures and greater flow rates, so their usefulness matched the production. Today, these same vessels, tanks, lines, wellheads, etc. maintain their integrity because they are properly serviced and maintained and can safely handle the corresponding

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<sup>169</sup> See sections XI.A.1.e (Delay of repair due to parts unavailability) of the final rule preamble for example.

natural operational decline of oil and gas production to levels far below the originally designed pressure and flow rates.

- Depletion of the producing formation is critical to understanding the actual operational oil and gas production regime, economic viability and the associated potential for emissions. Without site visits and experience gained from daily engagement with operational parameters, equipment and knowledge of producing formation dynamics, a regulator or special interest group couldn't possibly know how the proposed rule changes will affect each production profile of the numerous production basins throughout the United States. The commenter feels the EPA is publishing rules that do not pertain to any realistic operations within the oil and gas production industry segment and is largely driven by special interest groups that do not have the experience and intimate knowledge of each production regime. Once again, a "one-size-fits-all" approach is discriminatory and would place a tremendous financial burden on small business operators based on incorrect assumptions and data.

Response II-20-35: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

For the comment arguing that EPA's one-size fits all approach does not adequately address the variability across the industry and EPA's responses, see Volume I, Chapter 23 (Miscellaneous Other Comments), section 23.17 (One-Size Fits All Approach) of this RTC document.

Comment: Commenters (2168-INOGA, 2172-KOGA, 2179-KIOGA, 2322-ADEQ, 2393-OSEE et al) request that EPA reinstate the low production well exemption that was included in the previous rule and/or exclude small sources.

Commenters (2168-INOGA, 2172-KOGA) note that most of their members meet the definition of a small business. Members are disproportionately affected because they operate low production wells and do not have the technical capabilities to read and implement a regulation such as this proposal without substantial support. The commenters provide support by providing guidance and responding to EPA with comments that reflect the challenges of their members. The commenters request that EPA provide common-sense, cost-effective regulations, that can be implemented by all our members. The commenters note that many of their members have limited staffing available to manage day to day office activities and field maintenance work. The commenters state that exempting wells with a production level less than 15 barrels per day (or equivalent gas production) will provide significant relief for small businesses without measurable environmental impacts. The commenters believe that EPA's concerns about low

producing wells not being inspected (and leaks being repaired) by small businesses is not an accurate perspective.

Commenter (2179-KIOGA) urges EPA to exempt small businesses from the proposed rule. The commenter asserts that the proposed emission guidelines impose a burden and insurmountable costs for the small businesses.

Commenter (2322-ADEQ) urges EPA to reconsider including small sources in the scope of the Proposed Rule's requirements. The commenter expresses concern with this subset of existing well sites owned by individuals, farmers, small business operators, and family limited partnerships. The commenter notes that many rural households use natural gas production from wells located on their property, either through ownership or lease. The commenter contends that EPA has not fully analyzed the financial burden on homeowners, small business operators, and farmers that would result from the Proposed Rule, and the RIA does not address the costs resulting from new requirements for this subset of sources.

Commenter (2393-OSEE et al) objects to EPA eliminating the 3 tpy exemption threshold. The commenter notes that low-emitting wells which would fall below this exemption threshold are likely to be older wells, often referred to as stripper wells or marginal wells. ("Marginal" in this usage refers to the marginal profitability of these wells.) In spite of their low per-well productivity and profitability, the vast majority of existing wells are classified as stripper or marginal wells. The operation of these wells is important to Oklahoma's economy. The commenter notes that; "the tens of thousands of other older, marginal wells...represent a significant portion of Oklahoma's production and tax base.", "Most of the marginal wells are in rural areas, where they help the jobs and income [in] those parts of the state," "Marginal — or stripper — wells are defined as those that produce no more than 15 barrels of oil or 90,000 cubic feet of natural gas per day. Those wells represent the vast majority of the operational wells in Oklahoma and throughout the country. While their production is overshadowed by the newer, much more prolific horizontal wells, marginal wells promise to continue boosting the state and national economy well into the future", and "In Oklahoma, more than 90 percent of the state's 39,530 oil wells produced less than 15 barrels per day, while only 2.5 percent of the wells produced more than 100 equivalent barrels a day, according to a report the U.S. Energy Information Administration released this week."<sup>170</sup>

In spite of the low productivity of each stripper well, the commenter (2393-OSEE et al) states that the large number of stripper wells yields a significant amount of production in aggregate as is explained in the following analysis provided by the U.S. Energy Information Administration (EIA):

Stripper wells, or wells that produce small volumes, represent an important but decreasing share of total U.S. oil and natural gas production. These wells are characterized as producing no more than 15 barrels of oil equivalent per day (boe/d) over a 12-month period. EIA estimates that there were about 380,000 stripper oil wells (so

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<sup>170</sup> "Older, Marginal Wells Increase Nationwide," by Adam Wilmoth, The Oklahoman, December 15, 2017, online: <https://www.oklahoman.com/story/business/energy-resource/2017/12/15/older-marginal-wells-increase-nationwide/60555210007/>.

called because they are stripping the remaining oil out of the ground) in the United States operating at the end of 2015, compared to about 90,000 nonstripper oil wells.

The commenter (2393-OSEE et al) notes that wells become stripper wells through the normal decline of producing wells, some of which may have at one time been very prolific. These wells usually have low ongoing maintenance costs and relatively low transportation costs to move their products to distribution systems. As long as these wells are economically feasible, they are kept active and may continue to produce for many years.

The commenter (2393-OSEE et al) adds that despite each stripper well's small individual production, their large number ensures a significant contribution to total oil production. The production share of oil stripper wells has fallen from a high of 19 percent in 2008 to an estimated 10 percent in 2015.<sup>171</sup>

The commenter (2393-OSEE et al) explains that low maintenance costs and the fact that these wells are already tied into existing infrastructure (existing pipelines and transportation hubs) allows these wells to continue producing even though the profitability of each well is low. The commenter states that the vast number of wells not only provides a significant amount of crude oil and natural gas, but operating these wells employs a significant number of workers whose jobs would be eliminated were these wells to cease operation. The National Stripper Well Association (NSWA) quotes an Interstate Oil & Gas Compact Commission<sup>172</sup> estimate that closing U.S. stripper wells would result in the loss of 142,844 jobs.<sup>173</sup> A significant fraction of that impact would be felt in rural Oklahoma, impacting communities that can least afford to lose those jobs. Preserving the exemption threshold is essential to mitigating the negative impact of the proposed rule and maintaining the economic foundation for a number of socio-economically distressed Oklahoma communities.

Further, the commenter (2393-OSEE et al) notes that emissions from stripper wells are low. The U.S. DOE study on methane emissions from marginal wells reported average emissions ranging from 0.26 to 0.56 tons per year.<sup>174</sup> These wells are simply not large sources of emissions. If EPA is concerned about existing wells with emissions below the threshold becoming super-emitters, the commenter suggests this could be mitigated by a more efficient satellite-focused super-emitter detection and response program. In combination, these policies would eliminate the cost burden to low-emitting oil and gas operators, maintain employment in socio-economically distressed rural communities, and mitigate risk of significant methane emissions.

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<sup>171</sup> U.S. EIA, "Stripper Wells Accounted for 10% of U.S. Oil Production in 2015," June 29, 2016, online: <https://www.eia.gov/todayinenergy/detail.php?id=26872#>. EIA estimates that stripper wells contributed 7 percent of U.S. oil and natural gas in 2021. See the report, "The Distribution of U.S. Oil and Natural Gas Wells by Production Rate", U.S. EIA, December 2022, p. 9, online: [https://www.eia.gov/petroleum/wells/pdf/full\\_report.pdf](https://www.eia.gov/petroleum/wells/pdf/full_report.pdf).

<sup>172</sup> See <http://nswa.us/stripper-wells/>.

<sup>173</sup> EPA estimates the annual fugitive emission monitoring cost for a single well site or a single centralized production battery to be \$2,100. (See 87 Fed. Reg. 74728.) This cost will push the majority of stripper wells into closure.

<sup>174</sup> The results of the DOE study are referenced in the preamble at 87 Fed. Reg. 74729. Bowers, Richard L., "Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells," United States, available online: <https://www.osti.gov/biblio/1865859/>.

Response II-20-36: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

In response to comments regarding marginal wells, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. Moreover, to mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s). EPA is unable to assess the viability of the owners and operators of the marginal wells, and as such, EPA is therefore unable to predict which firms will be most adversely affected by regulatory costs.

Also with respect to marginal wells, EPA notes that recent studies, including the DOE study cited by one commenter (2393-OSEE et al), have suggested that low production, or marginal, wells account for roughly half of methane emissions from oil and natural gas production (see Chapter 6 of the TSD).

Comment: Commenter (2220-WDEQ) specifically refers to the overall impacts that EPA's monitoring requirements in the supplemental proposal will have because it now considers the amount and types of equipment at a site, rather than estimated emissions. The commenter expresses concern that many existing stripper wells could be burdened with onerous monitoring requirements. They add that many of these smaller sites simply cannot shoulder the financial burden associated with these requirements and the economic ramifications could be significant. According to the Wyoming Oil & Gas Conservation Commission (WOGCC), in 2019, there were 6,848 stripper wells in Wyoming that produced a total of 6,959,356 BBLs of oil for the year and in 2020, there were 6,524 stripper wells in Wyoming that produced a total of 5,970,758 BBLs of oil. According to the State of Wyoming Geological Survey, 288 companies, each producing less than 1 percent of Wyoming's total crude oil production, together account for 18 percent of the statewide production of crude oil; 181 companies, each producing less than 1 percent of Wyoming's total natural gas production, together account for 11 percent of the

statewide natural gas production.<sup>175</sup> The commenter notes that these small companies will be most significantly impacted by the requirements of the supplemental proposal, particularly those proposed in EG OOOOc, and some have indicated that they may have to shut in production because they cannot meet the compliance requirements in the supplemental proposal. According to the commenter, this will result in potentially significant adverse impacts to local communities around Wyoming.

The commenter (2220-WDEQ) emphasizes that stripper wells constructed after 1973 have already received permits under WDEQ's New Source Review program to address VOC emissions, and consequently methane emissions. The commenter anticipates that many of these wells may be further subject to the OGI monitoring requirements in the supplemental proposal. They add that there are an indeterminate number of stripper wells that will have to shutter operations due to the impossible cost of compliance with OGI monitoring requirements, and the consequential loss of jobs and mineral revenues could have damaging impacts upon Wyoming's economy, all while no significant environmental benefits occur from the onerous new proposed regulations.

The commenter (2220-WDEQ) suggests that the EPA represents the disproportionately high compliance costs specifically associated with EG OOOOc in the preamble and the RIA. In Tables 1-4 and 1-5 of the RIA, EPA indicates that the Net Compliance Costs and Compliance Costs are roughly 2.5 to 3 times higher for EG OOOOc than NSPS OOOOb over the period of 2023-2035, depending on the discount rate applied and whether present value or estimated annual value are considered. The commenter notes that it is difficult to know the true economic impact that the proposed regulations will have in Wyoming, but it is clear that small operators will be especially hard hit by the proposed EG OOOOc regulations. The commenter asserts that the economic viability of smaller operators, as well as site-specific and control program-specific considerations, must be taken into consideration when promulgating final regulations. The commenter notes that there are nuances to oil and gas production that are regionally specific and state-specific, and a set of blanket regulations simply does not account for these issues for operators in Wyoming.

Response II-20-37: In the revised IRFA and FRFA, EPA provides an extensive discussion of regulatory flexibility alternatives and notes key areas where options were chosen to reduce regulatory burden on small businesses. While, as a general matter, EPA's position is that, for the purposes of RFA compliance, only the NSPS OOOOb is relevant at the time of promulgation of this final rule, much of the discussion of regulatory flexibility alternatives in the revised IRFA found in the December 2022 RIA and the FRFA found in the final rule RIA apply to affected sources under each subpart. As an example, EPA revised its proposed fugitive emissions monitoring requirements at well sites to allow for AVO inspections at sites with little or no equipment, which EPA believes disproportionately alleviates regulatory burden on small businesses without sacrificing significant environmental benefits. In addition, EPA's analysis suggests that sites with little to no equipment are less likely to be impacted by process controller and pump requirements.

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<sup>175</sup> Wyoming State Geological Survey, Erin A. Campbell, Director and State Geologist, "Oil & Natural Gas Resources in Wyoming," January 2023 Summary Report.

In response to comments regarding marginal wells, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. Moreover, to mitigate the impact of abandoned wells, the Inflation Reduction Act (IRA) provides \$700 million for methane and greenhouse gas mitigation activities for conventional marginal wells. The Department of Energy and the EPA have issued a joint Notice of Intent to provide grants up to \$350 million for conventional marginal well plugging as an initial effort to distribute the IRA funds. The goal of marginal well funding from the IRA is to offset the cost of plugging low producing wells. Additionally, the federal money reduces the possibility that the operator files for bankruptcy and orphans their well(s). EPA is unable to assess the viability of the owners and operators of the marginal wells, and as such, EPA is therefore unable to predict which firms will be most adversely affected by regulatory costs.

Finally, EPA disagrees with the commenter's assessment that the estimated compliance costs associated with the EG OOOOc are disproportionately high. The discrepancy in estimated costs in the RIA between the NSPS OOOOb and the EG OOOOc are a function of the difference in the estimated numbers of affected facilities. EPA estimates that there will be far more EG OOOOc than NSPS OOOOb-affected facilities over the analysis horizon. By construction, the estimated costs will be roughly proportionate to the estimated number of affected facilities (see Section 2.2 of the Final RIA for more discussion on methodology).

#### ***20.4.6 Regional Considerations***

Comment: Commenter (2227-WEA) requests that EPA recognize and integrate regional differentiators in all aspects of the RIA, including differences between regions of the lower 48 states. Regionally differing economic, operational, and development parameters in the lower 48 states, just as with Alaska, play a key role in the resulting economic impacts that oil and natural gas rules create, including revenue and costs, and the feasibility of the implementation of proposed rules such as NSPS OOOOb and EG OOOOc.

As an example, the commenter (2227-WEA) states that associated gas for use in processes such as generating electricity and replacing functions like pneumatic controllers and pneumatic pumps will have characteristics that vary widely in different regions. For instance, the State of Colorado employs a default crude oil gas-to-oil-ratio of 23 standard cubic feet per barrel (scf/bbl) and the State of Utah has a default value of 17 scf/bbl for the Uinta Basin where the type of oil produced varies enough such that values as low as 5 scf/bbl are not uncommon. The Bureau of Land Management (BLM) recently used a value of 43 scf/bbl in evaluating the feasibility of using associated gas for on-site processes. The commenter recommends that all of these types of data be factored into an RIA, such as those for NSPS OOOOb and EG OOOOc, demonstrating the importance of regional considerations in the impact of the regulations. Specific recommendations provided include:

- Supplement the RIA by conducting a more thorough analysis that will account for significant regional challenges and differentiators that occur in distinctive parts of the

lower 48 states, such as the undeveloped, wide-open and topographically difficult expanses, and extreme weather conditions of the Rocky Mountain States.

- Analyze the regulatory impacts on a finer geographic scale than the broad-brush, one-size-fits-all, nationwide approach reflected in the proposed regulations.
- Modify proposed NSPS OOOOb and EG OOOOc regulations to account for unique economic, operational, and development challenges that exist as key differentiators across the broad spectrum of environments across the U.S.

Response II-20-38: EPA disagrees with the commenter's assessment that the RIA needs to assess regional implementation challenges associated with the electrification of oil and natural gas operations. While the RIA attempts to model important region-specific factors where possible (e.g., in the assignment of region-level major equipment distributions to model well sites), its primary purpose is to provide a best-estimate assessment of the nationwide impacts of the rule. Due to data limitations, EPA cannot feasibly account for local conditions across the country, and the commenter does not provide the necessary data to address these limitations.

## **20.5 Emissions Reductions and Associated Impacts**

### ***20.5.1 Oil and Natural Gas Sector Emissions***

Comment: Commenter (2168-INOGA) notes that the EPA states that the Oil and Gas segment is the largest industrial emitter of methane. In the preamble of prior rule makings, EPA published a table of the largest methane emitting industries. The commenter states that this table/analysis has not been provided in this rule making. According to the commenter, in the prior rule makings, EPA's own data shows the reduction in methane and VOC emissions over time, with (post-2016) and without (pre-2016) regulations imposed by EPA. The data tables in prior rule making do not support EPA's claim that the Oil and Gas segment is the largest industrial emitter of methane.

According to the Global Methane Initiative (GMI), the Oil and Gas segment is not the largest industrial emitter [the commenter adds Figure 1: Emissions by Sector in million metric tons of carbon dioxide equivalent (MMTCO<sub>2</sub>e)].<sup>176</sup> Table 1 [included in attachment to the commenter's letter] provides the U.S. EPA's Sector, Source, and Subsource fields were mapped to GMI sectors and categories.

Commenter (2168-INOGA) provides that data collected from EPA's website shows that Waste is the largest industrial emitter of methane in the U.S. (2021 data). Using the database provided by EPA and filtering for only methane emissions, the commenter notes that the Waste category emits almost 93 million metric tons of CO<sub>2</sub>e verses the Petroleum and Natural Gas Systems segment at less than 71 million metric tones of CO<sub>2</sub>e.

Response II-20-39: Based on the latest data under the U.S. Greenhouse Gas Inventory, the EPA maintains that the largest industrial emitter of methane is the oil and natural gas industry. The waste sector methane emissions data in the commenter-provided cite includes several different

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<sup>176</sup> <https://www.globalmethane.org/methane-emissions-data.aspx>.



industrial sources — wastewater, manure management, municipal solid waste (landfills), other waste.

See section III.B.2 (Emissions from the oil and natural gas source category) of the final rule preamble for a characterization of emissions from the oil and natural gas source category and summary of the U.S. methane emissions by sector (million metric tons carbon dioxide equivalent (MMT CO<sub>2</sub> Eq.) (See Table 7)).

See also See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

Comment: Commenter (2172-KOGA) states that the oil and gas industry would like to verify the actual performance of EPA's prior rule making verses the claims that were made when the rules were initially promulgated. The commenter makes the following inquires:

- Were prior rule makings successful at reducing emissions, as claimed during the development of the regulation?
- If EPA's rules failed to meet the advertised expectations, why is this current rule being promulgated?
- Does the actual performance data justify the actions, or is this a politically motivated rulemaking to increase the compliance burdens (i.e., operating costs) on the oil and gas industry?

According to the commenter (2172-KOGA), EPA should be required to show the data from prior rule makings, illustrating the expected emissions reductions and the actual emissions reductions prior to promulgating more significant regulations on the oil and gas industry.

Response II-20-40: The November 2021 Proposed Rule at Section I.A and the Final Rule at Section II.A discuss the purpose of this regulatory action in great detail. Commenter cites no authority for its contention that the EPA is required to verify the "performance" of prior rulemakings as a necessary component of promulgating this rulemaking, and the EPA is not aware of any such requirement.

Comment: Commenter (2257-MOGA) questions the EPA's use of 2019 emission data to justify the current proposed regulations. The commenter states that, based on historic rulemaking efforts, if the full implementation of NSPS OOOOa did not begin until roughly 2018 (considering the 2-year and 90-day court stay), how can the EPA determine the effectiveness of the NSPS OOOOa regulations and justify the new proposed regulations? The commenter reports that Michigan producers have been successful in reducing emissions through NSPS OOOO and NSPS OOOOa regulations. The commenter cites emissions reduction data from three small businesses that have invested significant capital to achieve emissions reductions without the EPA allowing enough time to recover costs. The commenter believes that the EPA should allow more time to evaluate current regulations applied to new sources and future modifications of

previously non-regulated sources before amending regulations resulting in another substantial economic burden on small business producers.

Response II-20-41: This commenter provided a similar comment on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.6.1 (General Opposition) Response I-23-14 for a response to this comment.

Comment: Commenter (2403-PAO) suggests that the EPA overestimates emissions and reduction benefits. The commenter states that the EPA estimated the quantity of emissions and potential reductions using its data that contains emission factors (EFs) and estimation methodologies that do not reflect actual emissions. In some instances, the commenter states that the EFs and estimation methodologies significantly overestimate emissions from sources e.g., pneumatic and liquids unloading. The commenter contends that the EPA's use of inaccurate emission data has erroneously justified excessive requirements for existing wells. Congress recognized this issue and incorporated into the Inflation Reduction Act a requirement for EPA to revise its Greenhouse Gas Reporting Program (GHGRP) Rule to allow reporting entities to collect and submit empirical emission data. The commenter requests that EPA reconsider its emission data and the associated regulatory requirements for the various emission sources located at existing wells. In addition, the commenter asserts that the EPA must update its emission factors and methodologies to reflect actual emissions from the oil and gas industry.

Response II-20-42: The commenter asserts that the EPA overestimates emissions and emissions reduction benefits because the underlying data used (e.g., GHGRP and GHGI data) contain emission factors, and that data should be based on actual emissions. The EPA believes that the use of average emissions factors based on the best available data will mean that some sources will have baseline emissions and emissions reductions based on the rule that will be overestimated for some sources and underestimated for other sources. Best available data will always evolve.

The EPA reviewed available data during the course of this rulemaking, including data submitted by commenters. Additionally, EPA has recently taken up multiple rulemakings, including NSPS OOOOb, revisions to 40 CFR part 98 subpart W (greenhouse gas reporting rule), and the Methane Emissions Reduction Program which will generate data to better quantify emissions from this sector. NSPS OOOOb and EG OOOOc include required methods for measuring emissions from various sources, such as control devices on affected facilities/designated facilities, in the final rulemaking.

With regards to the comment that EPA's use of what they contend is "inaccurate" emission data has erroneously justified excessive requirements for existing wells, we disagree. Many of the standards established for existing wells reflect control mechanisms and measures that many companies and sources around the country are already implementing — again, without deleterious effect on industry as a whole — which shows not only that such controls are "adequately demonstrated" but also underscores their reasonableness from a cost perspective. Also, as discussed in the final rule preamble, these final actions stem from the EPA's authority and obligation under CAA section 111 to directly regulate categories of new stationary sources that cause or contribute to endangerment from air pollution and to promulgate EG for states to

follow in regulating existing sources (designated facilities) in the source category. See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

**Comment:** Commenter (2460-Private Citizen) believes if the EPA is to properly monitor emissions and the changes in emissions over time, these emissions need to be listed in precise, meaningful terms. Worldwide data on emissions are frequently listed, on an annual basis, in either English tons or metric tonnes. The commenter also suggests that they could also be listed as volume of natural gas per time unit, which could be converted to tons or tonnes after it is normalized by using the percentage of methane in the natural gas produced at a given well-pad. The commenter notes that they would also need to know the gross production (or gross transport, gross material processed. etc.) to see whether emissions are approaching a minimum value.

Commenter (2460-Private Citizen) finds reporting emissions in carbon-dioxide equivalents on a 100-year basis is simply not meaningful. It deemphasizes the contribution made to global warming by methane in the first years after it is released. Reporting equivalence over one decade would make clear how important it is to drastically cut emissions in the next 10-15 years.

**Response II-20-43:** Methane is a powerful greenhouse gas. Methane is 28 times as potent as CO<sub>2</sub> over a 100-year time frame, and historical emissions of methane have contributed about a third of today's warming. Methane also contributes to increases in global tropospheric ozone levels, which damages human health and ecosystems. This action will contribute to reductions in methane emissions. However, only looking at relative impacts over the next 20 years is an incomplete comparison of methane and CO<sub>2</sub> impacts. The 100-year GWP value is more consistent with temporal valuation used elsewhere in US government cost benefit analyses. See, e.g., Sarofim and Giordano (2018, <https://esd.copernicus.org/articles/9/1013/2018/>) and Mallapragada and Mignone (2020, <https://link.springer.com/article/10.1007/s10584-019-02486-7>) which show that the 100-year GWP is equivalent to valuing future impacts with discount rate of about 3%, which is also the OMB Circular A-4 (2003) recommended discount rate for social goods.<sup>177</sup> A 20-year GWP would be equivalent to valuing future impacts at a much higher discount rate, which is inconsistent with how EPA (and many others) recommend valuing future damages and damages avoided. A 20-year GWP is not a good solution for avoiding tipping points: because it is a relative measure, using a 20-year GWP would lead to increased CO<sub>2</sub> emissions to balance reduced CH<sub>4</sub> emissions, which would reduce the probability of near-term tipping point exceedances at the cost of increasing the probability of passing tipping points in the longer term.

**Comment:** Commenter (2334-Liveable Arlington) states the EPA's new methane rules must be finalized soon and implemented with great urgency to protect communities like Arlington where resident exposure to fracking emissions is constant, has been happening for a long time, and severe because of mere 300 feet setbacks and high well density. The rules and monitoring

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<sup>177</sup> OMB Circular A-4 (2023) recommended a discount rate of 2.0% for such goods, which would be even less consistent with a 20-year GWP.

systems required for urban drilling in places like Arlington and its neighboring cities in the Barnett shale must be more stringent, with severe penalties for non-compliance.

Commenter (2334-Liveable Arlington) states EPA must also use the supplemental rulemaking to follow through on their commitment to community monitoring programs and work to incorporate emission monitoring results generated by community groups. This important step would allow the agency to accept and prioritize monitoring results from communities and ensure major leaks that are harming nearby communities are fixed more quickly. Incorporating community programs will expand EPA's capacity to identify and fix leaks at sites across the country and help curb methane waste and pollution.

Commenter (2334-Liveable Arlington) argues the EPA must recommend safe setbacks between fracking operations and protected uses and exposed residents. In Arlington, Total Energies and other drillers frack next door to many daycares, for instance with no safeguards at distances of 300 feet between the wellheads and the main structure of the childcare facility. The commenter also recommend that the EPA require fenceline monitoring with data reported in real time at fracking sites at distances less than 1500 feet from homes, schools, daycares, and medical facilities.

Commenter (2334-Liveable Arlington) adds Tarrant County in Texas is a special case - here there are the most residents living close to drilling than any other county in America. Even with the best technology in place, burning dirty fossil fuels places future generations at extreme risk from climate change. While supporting a rapid shift to clean, renewable energy, the commenter strongly urges the EPA to implement much tougher emissions rules for new AND existing oil and gas facilities in the interim, to help preserve not just a Liveable Arlington, but also a Liveable Planet for our children.<sup>178</sup>

Response II-20-44: See Chapter 23 (Miscellaneous Other Comments), subsection 23.2.1 (Climate Change and Air Quality Impacts on EJ Communities), Response II-23-7, for response to similar comments provided by this and other commenters.

Comment: Commenter (2334-Liveable Arlington) states the EPA must recommend safe setbacks between fracking operations and protected uses and exposed residents. In Arlington, Total Energies and other drillers frack next door to many daycares, for instance with no safeguards at distances of 300 feet between the wellheads and the main structure of the childcare facility.

Commenter (2334-Liveable Arlington) stresses methane has more than 80 times the warming power of carbon dioxide over the first 20 years after it reaches the atmosphere. Even though CO<sub>2</sub> has a longer-lasting effect, methane sets the pace for warming in the near term. Methane set a record for the second year in a row, scientists reported, just as the UN's panel on climate change warned the world is running out of time to rein in fossil fuel emissions. Methane — the second

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<sup>178</sup> [Comment includes 3 images/photos of fracking in Arlington that show proximity to homes and daycares. Moreover, comment includes a table of the EJScreen Report (Version 2) .25 miles ring centered at 32.740292, -97.098904, Texas, EPA Region 6 (100pprox.. pop: 1006. Also included is a link to Jan 2023 public hearings Eventbrite page and the following link, <https://drive.google.com/file/d/1K-bdJG7LDnEG-Ycnls-loRAheJV9Lp7/view>, to addition Liveable remarks – already excerpted elsewhere].

largest contributor to the human-caused climate crisis after carbon dioxide — increased by 17 parts per billion in 2021. According to the National Oceanic and Atmospheric Administration, this is the largest amount since measurements began nearly 40 years ago.

Commenter (2334-Liveable Arlington) adds toxic pollutants released alongside methane, such as VOCs, can worsen asthma and respiratory disease while toxics like benzene increase the risk of cancer, cause immune system damage and developmental problems. Living near unconventional oil & gas wells has been shown to shorten life spans for residents 65 and older.

Response II-20-45: See Chapter 23 (Miscellaneous Other Comments), subsection 23.2.1 (Climate Change and Air Quality Impacts on EJ Communities), Response II-23-7, for response to similar comments provided by this and other commenters.

Comment: Commenter (2320-American Public Gas Association (APGA)) asks EPA, with any future regulatory action, to not forget that natural gas is the significant driver behind the declines in emissions in our country.<sup>179</sup> The agency should recognize that continued natural gas use paired with responsible production will further these reductions in GHG emissions.<sup>180</sup>

Response II-20-46: EPA believes that the finalized NSPS OOOOb and EG OOOOc will help ensure responsible production of oil and natural gas.

Comment: Commenter (2227-WEA) argues the proposed rule will adversely affect the supply, distribution, and use of energy, resulting in higher costs to consumers. The preamble clearly states that the proposed rules will have a significant adverse effect on energy supplies and consumption:

“This action, which is a significant regulatory action under Executive Order 12866, has a significant adverse effect on the supply, distribution or use of energy. The documentation for this decision is contained in the Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review prepared for the November 2021 proposal and the Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review for this action.”<sup>181</sup>

Commenter (2227-Western Energy Alliance) believes certain provisions in the proposed rules could render significant oil and natural gas facilities in the United States, particularly marginal wells, uneconomic to operate, further constraining domestic supply, increasing energy prices, and making America more dependent on oil and natural gas produced overseas, beyond EPA’s

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<sup>179</sup> The U.S. Energy Information Administration reported that switching to natural gas accounted for almost two thirds of the CO<sub>2</sub> emission reductions from 2006 to 2014.

<sup>180</sup> United States Environmental Protection Agency, “Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020,” <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>.

<sup>181</sup> Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 87 Fed. Reg. 74702 December 6, 2022.

jurisdiction. EPA has ignored the fact that the rules will force the shutting in of wells in the United States and result in more imports from less regulated countries, ultimately increasing global greenhouse gas emissions and introducing other negative externalities.

Response II-20-47: EPA models the impact of the rule on oil and natural gas supply in Section 4.1 of the Final RIA. EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the impact on natural gas prices will be \$0.06/Mcf or less, and the impact oil prices will be \$0.25/bbl or less. These represent changes of approximately 1.76% and 0.33%, respectively.

With respect to the comment regarding marginal wells, EPA also developed a financial analysis of marginal, or stripper, oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. To the extent that any marginal wells might be plugged in relation to anything contained within this rulemaking (which is speculative), the analysis suggests that they would be extremely low-producing wells.

Finally, EPA estimates that the change in oil imports would be an increase of 1.05% or less but are unable to quantify the impact on GHG emissions of changes in imports. However, the relatively small estimated increase in imports suggests that the net effect on GHG emissions will be negligible.

### ***20.5.2 Secondary Impacts***

Comment: Commenters (2223-TAEP, 2308-NSWA) express concern that the oil and gas production decrease in the U.S. will result in increased global production and emissions.

Commenter (2308-NSWA) asserts that the regulation will increase emissions globally due to reduced domestic production as it is curtailed -- or in some places shuttered. The commenter believes that such action will result in increased imports of oil and natural gas from producing countries with lower environmental and labor standards (i.e., India, China, Russia). The commenter believes that reducing production in the U.S. will result in higher emissions, higher costs to consumers, and have the opposite effect of EPA's proposed regulation.

The commenters (2223-TAEP, 2308-NSWA) urge EPA to undertake a robust analysis, made publicly available prior to the implementation of the rule, to determine whether the result of the rule will be to raise production -- and thereby emissions -- in other producing countries and regions around the world to meet what will continue to be growing U.S. and global demand. The commenter believes that this analysis should by no means be limited to oil and natural gas, as numerous industrial processes and manufacturing have been exported overseas; however, as the EPA is contemplating new regulations on domestic oil and natural gas production, the commenters urge the analysis to begin there.

Commenter (2223-TAEP) contends that EPA must account for the negative externalities of reducing domestic production in favor of overseas competition. This would result in higher overall emissions and the commenter states that EPA must prepare a detailed analysis to reduce overall global emissions by harnessing American production and innovation.

The commenter (2223-TAEP) urges EPA to re-consider adopting regulations that may negatively affect the U.S. domestic production of crude oil and natural gas, as doing so will do nothing to affect the demand for those products. In fact, the successful application of the methane rule now under consideration is utterly dependent on maintaining or growing production in the U.S., and in Texas. The commenter asserts that a responsible and effective regulatory structure that allows the U.S. domestic oil and gas industry to flourish, not flounder, is the key to the achievement of the desired environmental benefits. The commenter contends that emissions are global in nature, and reducing domestic production in favor of production in other regions results in greater environmental harm, not less.

Response II-20-48: The commenter (TAEP) did not provide data to substantiate the claim that oil and gas production decrease in the U.S. will result in increased global production and emissions. EPA models the impact of the rule on oil and natural gas supply in Section 4.1 of the Final RIA. EPA estimates that the reduction in U.S. oil production would be approximately 1.05% or less, while the reduction in gas production would be approximately 0.75% or less. EPA estimates that the change in oil imports would be an increase of 1.05% or less but are unable to quantify the impact on GHG emissions of changes in imports. However, the relatively small estimated increase in imports suggests that the net effect on GHG emissions will be negligible.

Comment: Commenter (2223-TAEP) notes the emissions-reducing benefits of sufficient infrastructure to move crude oil and natural gas from the field to the marketplace-emissions from production operations decline as sufficient pipeline and other takeaway infrastructure is in place. The commenter requests that EPA consider this important relationship when imposing these regulations in a way that may limit the development of pipelines and other infrastructure by making it more expensive.

Response II-20-49: The EPA agrees that access to a pipeline and other takeaway infrastructure often provides for regulatory options that mitigate emissions to the atmosphere (e.g., routing gas to a sales line). In fact, for both new and existing well affected facility associated gas sources, BSER was determined to be routing to a sales line. The EPA allows for beneficial uses of the associated gas that are equivalent to routing to a sales line, but routing to a sales line is BSER. In general, routing to a process or sales line is encouraged under NSPS OOOOb and EG OOOOc, as such, the final rules are not anticipated to limit the development of pipelines or other infrastructure.

Comment: Commenter (2248-NDPC) urges EPA to consider secondary emissions impacts in its analysis (e.g., from manufacturing and transportation related equipment, construction equipment, and removal and disposal of equipment before the end of its useful life). The commenter states that EPA is proposing significant new requirements on low-emitting sources without considering the resulting secondary emissions. The commenter notes that typically, NSPS regulations only apply to criteria pollutants, and evaluating secondary emissions is not appropriate. However,

since this NSPS also regulates methane, the commenter believes that EPA's actions could have a more significant negative global impact than the small source the EPA is trying to control.

Response II-20-50: EPA disagrees that it needs to consider lifecycle emissions impacts in its analysis of the final rule. While EPA agrees that in certain circumstances such analyses might be important, the finalized requirements are sufficiently similar in nature to current industry practices that they will not drastically affect upstream or downstream emissions in the manufacturing or disposal processes. To the extent that any such impacts occur, they would likely be covered by other regulatory regimes. Moreover, commenter does not provide any analysis, data or legal authority that supports the need for such an analysis from EPA.

See section VIII.B (How does the EPA evaluate control costs in this final action?) of the final rule preamble. The EPA does not quantify lifecycle emissions impacts, but EPA does consider secondary emissions of regulatory options when determining BSER.

### ***20.5.3 General Climate and Air Quality Impacts***

Comment: Commenter (2344-IER) notes that EPA presents a sensitivity analysis of the monetized climate benefits using a set of SC-CH<sub>4</sub> estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). The EPA notes that the benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866.<sup>182</sup> The commenter suggests that one reading of this is that EPA does not consider climate change impacts to be legally relevant when establishing BSER, but rather, EPA is including these impacts because of E.O 12866. If this is the case, the commenter states that the EPA does not clearly explain this argument.

The commenter (2344-IER) provides that key statutory provision for setting BSER is CAA section 111(a)(1) which reads, “the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.”<sup>183</sup> EPA has stated that “In determining the BSER, EPA considers technical feasibility, cost, non-air quality health and environmental impacts, and energy requirements.”<sup>184</sup>

Commenter (2344-IER) suggests that the problem is that EPA's description of climate impacts of methane does not include air quality impacts. In the Regulatory Impact Analysis, EPA states:

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere,

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<sup>182</sup> 87 Fed. Reg. at 74713.

<sup>183</sup> 42 U.S.C. 7411(a)(1).

<sup>184</sup> EPA, Fact Sheet: The Affordable Clean Energy Rule (ACE), [https://www.epa.gov/sites/default/files/2019-06/documents/bser\\_and\\_eg\\_fact\\_sheet\\_6.18.19\\_final.pdf](https://www.epa.gov/sites/default/files/2019-06/documents/bser_and_eg_fact_sheet_6.18.19_final.pdf) change impacts of methane reductions in setting BSER.



which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice sheets, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.<sup>185</sup>

The commenter (2344-IER) states that these could be “non-air quality health and environmental impacts” and EPA could be considering them in setting BSER, but EPA does not describe what it is including in its analysis. The commenter requests that the EPA clarify if it is considering climate impacts in setting BSER for these sources.

Response II-20-51: The Final Rule preamble at Section VIII.B explains in detail how the EPA considered cost in setting standards of performance in NSPS OOOOb and EG OOOOc, which, under the requirements of CAA Section 111(a)(1), reflect the application of the best system of emission reduction adequately demonstrated. Both as part of evaluating the cost-effectiveness of potential systems of emission reduction and more broadly, the EPA has considered the amount of emission reductions of, as applicable, VOC and/or methane, achievable through application of the BSER identified in the Final Rule. These reductions are intended to address the endangerment to public health and welfare (including the climate impacts) that undergird the EPA’s promulgation of standards and Emission Guidelines for this sector. See discussion in Section III for the EPA’s discussion of emissions and impacts of the sector; Section V for the Legal Basis for the Final Rule; and Section VIII.B of the Final Rule preamble for discussion of the EPA’s evaluation of the advantages and disadvantages of this action.

Separately, the Final Rule preamble at Section II.C explains in detail how the EPA projected the emissions reductions, costs, and benefits that may result from this final rulemaking, in accordance with the requirements of E.O. 12866. As explained in the Final Rule Preamble Section II.C, the benefits analysis conducted pursuant to E.O. 12866 is distinct from the BSER determinations, which are based on the statutory factors the EPA is required to consider under section 111(a) of the CAA (including cost, energy requirements and non-air quality health, and environmental impacts). The E.O. 12866 assessment described in the Final Rule Preamble and in the RIA is presented solely for the purposes of complying with E.O. 12866 and providing the public with a complete depiction of the impacts of the rulemaking.

Comment: Commenter (2367-BlueGreen Alliance) states that methane standards result in climate, public health, and economic benefits. The commenter states that the proposed rule will expedite technology deployment and emissions reduction.

The commenter (2367-BlueGreen Alliance) notes that low-cost, proven measures and technologies are already commercially available to cut methane emissions from the oil and gas sector by 65 percent in the next five years.<sup>186</sup> While some companies have moved to adopt these

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<sup>185</sup> Environmental Protection Agency, Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, p. 64, Nov. 2022.

<sup>186</sup> Clean Air Task Force, Reducing Methane from Oil and Gas, December 2020. Available online: [https://cdn.catf.us/wp-content/uploads/2020/04/21092556/Path\\_to\\_65pc\\_OG\\_reductionDec2020\\_update.pdf](https://cdn.catf.us/wp-content/uploads/2020/04/21092556/Path_to_65pc_OG_reductionDec2020_update.pdf).

improvements voluntarily,<sup>187</sup> the prospects of keeping gas in the system with available and cost-effective mitigation technology could improve with a larger market and level regulatory playing field among energy companies. The commenter notes that some states, such as Colorado, already have strong methane pollution standards in place. These standards have resulted in climate, public health, and economic benefits while stabilizing industry by reducing energy waste.<sup>188</sup>

Despite these readily available mitigation options, the commenter (2367-BlueGreen Alliance) contends that voluntary efforts by oil and gas companies have been uneven<sup>189</sup> and limited regulations leave out most sources and sites, leading to emissions growth.<sup>190</sup> The proposed rule reflect the necessity to reduce waste and pollution at new, modified, and existing sources. The commenter asserts that having the standard in place also provides an opportunity for companies to innovate in methane mitigation technology and strategies and provides greater regulatory certainty for the industry over the long run.

Commenter (2367-BlueGreen Alliance) also states that reducing methane leaks yields benefits to workers, communities, and climate.

The commenter (2367-BlueGreen Alliance) asserts that the threat of catastrophic climate change has reached a crisis point. According to IPCC's Sixth Assessment Report, the window to prevent the worst effects of warming is rapidly closing.<sup>191</sup> The commenter contends that keeping the world on its target of 1.5°C of warming will require immediate action to reduce the emission of greenhouse gasses. Of the GHGs being emitted, methane is one of the most potent, with one ton of methane in the atmosphere having over 80 times the warming impact of a ton of carbon dioxide (CO<sub>2</sub>) in the twenty years after it is emitted.<sup>192</sup> While methane emissions occur in many sectors, the oil and gas sector stands together with agriculture as the largest source of this pollution in the U.S. The commenter states that methane is emitted from oil and gas infrastructure like wells, compressor stations, and processing plants alongside other dangerous compound, such as VOCs, which form smog and soot, and carcinogens like benzene,

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<sup>187</sup> McKinsey, Curbing Methane Emissions, Sep 2021. Available online: <https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/curbing%20methane%20emissions%20how%20five%20industries%20can%20counter%20a%20major%20climate%20threat/curbing-methane-emissions-how-five-industries-can-counter-a-major-climate-threatv4.pdf>.

<sup>188</sup> Clean Air Task Force, Good Rules, Good Jobs: Employment Opportunities From Emissions Standards for Oil and Gas, September 2022. Available online: [https://cdn.catf.us/wp-content/uploads/2022/10/04105136/CATF\\_OilGasJobsReport-1.pdf](https://cdn.catf.us/wp-content/uploads/2022/10/04105136/CATF_OilGasJobsReport-1.pdf).

<sup>189</sup> ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries. March 2014. Available online: [https://www.edf.org/sites/default/files/methane\\_cost\\_curve\\_report.pdf](https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf).

<sup>190</sup> Clean Air Task Force, Fossil Fumes (2022 Update): A public health analysis of toxic air pollution from the oil and gas industry, September 2022. Available online: <https://cdn.catf.us/wpcontent/uploads/2016/06/14175846/fossil-fumes-report-2022.pdf>.

<sup>191</sup> IPCC, Climate Change 2022: Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, 2022. Available online: [https://report.ipcc.ch/ar6/wg2/IPCC\\_AR6\\_WGII\\_FullReport.pdf](https://report.ipcc.ch/ar6/wg2/IPCC_AR6_WGII_FullReport.pdf).

<sup>192</sup> U.S. EPA, Understanding Global Warming Potentials. Available online: <https://www.epa.gov/ghgemissions/understanding-global-warming-potentials>.

formaldehyde, and acetaldehyde.<sup>193</sup> The communities facing the greatest public health risk from these harmful air pollutants are in states with the greatest amount of oil and gas development, including New Mexico, Texas, Colorado, Pennsylvania, Oklahoma, Louisiana, West Virginia, and North Dakota.

The commenter (2367-BlueGreen Alliance) notes that, across the country, nearly 14 million people living in one of 236 counties in 21 states face a cancer risk greater than the EPA's one-in-a-million threshold for concern due to oil and gas alone.<sup>194</sup> Oil and gas sector air pollution is particularly harmful to workers that serve in that industry, who face serious long term health challenges as a result of their labor. Emissions reduction for this sector can significantly improve air quality for workers and communities, preventing 255,000 premature deaths and more than half a million asthma-related emergency room visits globally each year.<sup>195</sup>

The commenter (2367-BlueGreen Alliance) contends that the nation's energy sector has made significant strides to increase the efficiency of gas and oil systems in recent years. However, emissions of methane and other pollutants continue to harm the economy and the environment by jeopardizing the health of workers and communities, wasting resources, and worsening climate change. Moreover, recent research suggests emissions from oil and gas activities are significantly underestimated in the EPA's latest greenhouse gas inventory.<sup>196</sup> In fact, the International Energy Agency's (IEA) 2022 Global Methane Tracker analysis found that national governments underestimated methane emissions from the energy industry globally by 70 percent.<sup>197</sup>

Commenter (2335-Karro) stated that the benefits of the proposed regulations are greatly appreciated, especially that EPA estimates that the supplemental proposal would:

- Avoid an estimated 36 million tons of methane emissions from 2023 to 2035, the equivalent of 810 million metric tons of carbon dioxide – nearly the same as all greenhouse gases emitted from coal-fired electricity generation in the U.S. in 2020.
- Yield \$3.1 to \$3.2 billion in climate benefits per year, with total net benefits (after taking the costs of the rule into account) valued at \$34 to \$36 billion from 2023 through 2035.
- Increase recovery of natural gas -- valued at \$3.3 to \$4.6 billion from 2023 through 2035 (based on forecasted prices) – that otherwise would go to waste.

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<sup>193</sup> Clean Air Task Force, Fossil Fumes (2022 Update): A public health analysis of toxic air pollution from the oil and gas industry, September 2022. Available online: <https://cdn.catf.us/wpcontent/uploads/2016/06/14175846/fossil-fumes-report-2022.pdf>.

<sup>194</sup> Ibid.

<sup>195</sup> UN Environment Programme, Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions, May 2021. Available online: <https://www.unep.org/resources/report/global-methaneassessment-benefits-and-costs-mitigating-methane-emissions>.

<sup>196</sup> Harvard SEAS, "Oil and natural gas production emit more methane than previously thought". March 22, 2021. Available online: <https://www.seas.harvard.edu/news/2021/03/oil-and-natural-gas-production-emitmore-methane-previously-thought>.

<sup>197</sup> IEA, "Methane emissions from the energy sector are 70% higher than official figures", February 23, 2022. Available online: <https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higherthan-official-figures>.

The commenter (2335-Karro) adds that seldom do we see a proposed rulemaking from any government agency that goes so far to helping achieve the Administration's stated climate goals.

Commenter (2249-NACAA) notes that the EPA has updated its figures in the supplemental proposal and now finds the programs would reduce 36 million tons of methane emissions from 2023 to 2035. While this is a lower volume than was estimated in the initial November 2021 proposal, the commenter suggests that these methane reductions would still significantly reduce harms and offer public health protections on a local basis and would help address the ongoing crisis facing the planet's climate. While not a criteria pollutant covered by the NAAQS, methane remains a potent climate pollutant with a global warming potential nearly 30 times that of CO<sub>2</sub>.

Commenter (2209-PLS) states that oil and gas industry is one of the largest sources of methane pollution in the US, and studies show that reducing oil and gas methane is the easiest and most effective action we can take to address climate change. The commenter reports that, according to the International Energy Agency, half of global oil and gas methane emissions can be eliminated at no net cost. The commenter notes that many companies in the oil and gas industry support a strong EPA Methane Rule;<sup>198</sup> and both large and independent oil and gas operators have committed to end routine flaring. The commenter provides the following examples: ExxonMobil committed to end routine flaring across its assets in the Permian Basin by 2022, BP committed to end routine flaring by 2025 in its U.S. onshore operations, and many more have signed on to the World Bank's goal of ending routine flaring worldwide by 2030.<sup>199</sup>

Response II-20-52: EPA acknowledges the supportive comments.

Comment: Commenter (2293-Holmes) expressed that they appreciate EPA sharing estimates of climate benefits over the 2023 to 2035 period to be \$48 billion at a 3-percent discount rate, and that "these values represent only a partial accounting of climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions." Numbers mentioned in the RIA, such as "global ozone-related mortality benefits of CH<sub>4</sub> emissions reductions, which are not included in the social cost of methane valuations, [are estimated] to be \$800 to \$1,800 per metric ton of methane emissions" are useful at some level. What would be more helpful at the state level, though, would be a set of clearly prescribed methane and other social cost of greenhouse gas cost valuations that can readily be applied to energy and environmental policy making and utility regulation.

Response II-20-53: A detailed response regarding the damage categories omitted from EPA's SC-GHG estimates and the use of these estimates in policy can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

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<sup>198</sup> See <https://www.reuters.com/business/environment/us-unveils-crackdown-methane-starting-with-oil-gas-rules-2021-11-02/>, [https://www.bp.com/en\\_us/united-states/home/news/press-releases/bp-statement-on-proposed-methane-rules.html](https://www.bp.com/en_us/united-states/home/news/press-releases/bp-statement-on-proposed-methane-rules.html).

<sup>199</sup> See About the ZRF ([worldbank.org](https://www.worldbank.org)).

Comment: Commenter (2413-CEI) states that the reductions in climate-related damages, estimated at \$55 billion, account for 100 percent of the proposal's monetized benefits. According to the commenter, the vast majority of climate damages are attributed to the direct and indirect effects of global warming. The commenter inquires "How much warming would the proposal avert?" The note that neither the proposal itself nor the accompanying RIA explicitly addresses that question.

However, the commenter (2413-CEI) provides that other information in the RIA combined with EPA's climate policy model allows us to estimate the proposal's potential effects on global surface temperatures using the agency's own forecasting assumptions.

The commenter (2413-CEI) provides that the proposed standards are projected to eliminate 910 million metric tons (MMT) of carbon dioxide-equivalent (CO<sub>2</sub>e) methane emissions during 2023-2035.<sup>200</sup> The EPA's *Model for the Assessment of Greenhouse Gas Induced Climate Change*, better known as MAGICC,<sup>201</sup> calculates the temperature effects of emission scenarios under different climate sensitivity assumptions. Climate sensitivity is a term used to describe how much warming results after the climate system fully adjusts to a doubling of CO<sub>2</sub>e greenhouse gas concentration.

The commenter (2413-CEI) goes on to note that the proposal's reduction of 920 MMT CO<sub>2</sub>e over 13 years averages about 71 MMT per year. [Table provided in comment letter shows estimated emission changes from NSPS OOOOb and EG OOOOc proposals for methane, VOC, and HAP.] In 2019, the commenter notes that U.S. GHG emissions in CO<sub>2</sub>e were about 6.6 billion metric tons.<sup>202</sup> A reduction of 71 MMT is about one-tenth of 1 percent of 2019 U.S. GHG emissions. Using MAGICC, the commenter reports that they get the following predicted temperature reductions by 2050 and 2100:

- 4.5°C sensitivity, 0.005°C reduction by 2050, 0.014°C reduction by 2100
- 3.0°C sensitivity, 0.004°C reduction by 2050, 0.011°C by 2100
- 2.0°C sensitivity, 0.003°C reduction by 2050, 0.008°C by 2100<sup>203</sup>

For perspective, the commenter (2413-CEI) provides that the standard deviation for measuring changes in global annual average surface temperature is 0.11°C.<sup>204</sup> Thus, the proposal's projected effects on global warming are undetectable. By the same token the proposal's potential effects on weather patterns, crop yields, coastal flooding, polar bear populations, and other climate-related environmental conditions would also be undetectable. Of greater policy relevance, they state that such benefits are too small to be experienced by people and other living things. They suggest that benefits that can neither be detected nor experienced are so in name

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<sup>200</sup> RIA, Table 1-3, p. 1-10.

<sup>201</sup> <https://magicc.org>.

<sup>202</sup> EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, <https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019>.

<sup>203</sup> These estimates are linear extrapolations and not strictly correct because radiative forcing equations are logarithmic. Nonetheless, the calculations suffice as first order approximations.

<sup>204</sup> The standard deviation of the surface (land-ocean) temperature record is about 0.11 degrees C. See J. Hansen, et. Al. 1999. GISS Analysis of Surface Temperature Change. *Journal of Geophysical Research*, Vol. 104, No. D24, 30,997-31,022, <https://agupubs.onlinelibrary.wiley.com/doi/pdf/10.1029/1999JD900835>.

only. They argue that illusory “benefits” should not be weighed in the same scales with multi-billion-dollar compliance costs that verifiably impose measurable burdens on identifiable people and businesses.

Response II-20-54: EPA modeled emissions and emissions reductions of GHGs controlled by the standards (i.e., CH<sub>4</sub>); monetized the benefits of those emissions reductions (SC-GHG); and in addition, section 2020 (a) (1) does not require quantification of some degree of harm either to find contribution to endangerment, or (2) find that emission reductions will have some significant degree of harm reduction. Moreover, the rule results in "meaningful mitigation of greenhouse gas emissions" — over 1.5 billion metric tons of CO<sub>2</sub>e over the program's lifetime. Id. at 331 (reduction of 960 million metric tons of CO<sub>2</sub>e emissions provides meaningful mitigation).

The SC-GHG is the monetary value of the net harm to society from emitting a metric ton of that GHG into the atmosphere in a given year. In principle, the SC-GHG is a comprehensive metric that includes the value of all future climate change impacts (both negative and positive), including changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG, therefore, also reflects the societal net benefit of reducing emissions of the GHG by a metric ton. EPA's *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* shows that even small reductions in GHG emissions and small reductions in temperature will have significant climate mitigation benefits.

Comment: Commenter (2413-CEI) states that the proposal aims to plug, prevent, or limit CH<sub>4</sub> releases from a wide variety of structures, equipment, and processes:

As natural gas moves through the necessarily interconnected system of exploration, production, storage, processing, and transmission that brings it from wellhead to commerce, emissions primarily result from intentional venting, unintentional gas carry-through (e.g., vortexing from separator drain, improper liquid level settings, liquid level control valve on an upstream separator or scrubber does not seat properly at the end of an automated liquid dumping event, inefficient separation of gas and liquid phases occurs upstream of tanks allowing some gas carry-through), routine maintenance, unintentional fugitive emissions, flaring, malfunctions, abnormal process conditions, and system upsets. These emissions are associated with a range of specific equipment and practices, including leaking valves, connectors, and other components at well sites and compressor stations; leaks and vented emissions from storage vessels; releases from natural gas-driven pneumatic pumps and controllers; liquids unloading at well sites; and venting or under-performing flaring of associated gas from oil wells.

In all, the commenter (2413-CEI) notes that the EPA itself expects regulatory authorities to manage nearly 1 million supply-chain links. Specifically, the proposed NSPS apply to an estimated 36,150 entities, components, or operations in 2023. When existing source EG take effect in 2026, a staggering 968,320 entities will be subject to new, stricter, or expanded CH<sub>4</sub>

regulation, according to the RIA.<sup>205</sup> [See Table 2-5 of the RIA. Projection of Incrementally Impacted Affected Facilities Under the Primary Proposed NSPS OOOOb and EG OOOOc Option, 2023 to 2035.]

The commenter (2413-CEI) states that since methane is the main component of natural gas and a saleable product, oil and gas producers, processors, and transmitters already have strong financial incentives to plug leaks and capture fugitive emissions. The commenter asks what benefit-cost calculation makes the proposed regulatory surge a smart investment of public and private resources?

The commenter (2413-CEI) asserts that the EPA estimates that, during 2023-2035, its preferred option (“primary proposal”) will generate \$55 billion in climate benefits, \$13 billion in compliance costs, \$7.2 billion in net compliance costs (i.e., \$13 billion minus \$5.5 billion in recovered product sales), and net benefits of \$48 billion.<sup>206</sup> The proposal thus looks like an amazing deal, with climate benefits exceeding compliance costs by 4.2 to 1 or (factoring in product recoveries) 7.6 to 1. Upon inspection, however, the commenter asserts that those benefits are “make-believe” and that the proposal would impose enormous costs for undetectably small benefits.

Near the end of the proposal, the commenter (2413-CEI) states that the EPA asserts that its climate-benefit calculations are not a factor influencing regulatory stringency: “However, we emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866.”<sup>207</sup> The commenter (2413-CEI) asserts that this disclaimer does not shield the proposal from litigation risk. E.O. 12866 itself serves a more basic rule of reason. As the Supreme Court stated in its review of the Mercury Air Toxics Standards (MATS) rule in *Michigan v. EPA*: “One would not say that it is even rational, never mind ‘appropriate,’ to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits . . . No regulation is ‘appropriate’ if it does significantly more harm than good.”<sup>208</sup>

The commenter (2413-CEI) contends that the EPA’s proposal is not reasonable if the climate benefits are illusory. An unreasonable regulation may be challenged as arbitrary and capricious.

Response II-20-55: The EPA disagrees with the commenter’s contention that the climate benefits of this rulemaking are “make-believe” or “illusory,” and also disagrees with the notion that the Final Rule will impose “enormous costs for undetectably small benefits.” In addition, the EPA has carefully considered how the Supreme Court’s ruling in *Michigan v. EPA*, 576 U.S. 743

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<sup>205</sup> EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, October 2021. ([https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf)).

<sup>206</sup> RIA, Table 5-4, p. 5-7.

<sup>207</sup> 87 FR 74843. BSER stands for “best system of emission reduction.” Clean Air Act section 111 performance standards are to reflect the degree of emission limitation achievable by the best system of emission reduction, taking into consideration cost, energy requirements, and non-air environmental impacts.

<sup>208</sup> *Michigan v. E.P.A.*, 576 U.S. 743, 752 (2015), <https://supreme.justia.com/cases/federal/us/576/14-46/case.pdf>.

(2015) applies to this rulemaking. For a detailed discussion of both issues, the EPA refers the commenter to the Final Rule preamble at Section VIII.B.

Comment: Commenter (2313-Plevin-Foust) urges the EPA to update the SC-GHG estimates with a uniform value of life equal to the value assigned to an American. The commenter argues that this may significantly increase the SC-GHG and states that this is in America's self-interest for the following reasons:

*Climate stability:* A higher social cost of carbon will spur businesses and governments at all levels to reduce greenhouse gas emissions more quickly and dramatically. We'd all become more concerned about climate change and willing to innovate more quickly to the green economy we know we must create. It could speed the development of carbon sinks like ocean kelp farms and healthy soil. Our example would goad other countries to do the same, decreasing the risk of cascading climate system failures and species extinctions that can't be reversed.

*Global influence:* The social cost of carbon that we adopt will likely be copied by Canada, another high-emitting country, and other nations. Our ties with allies and other nations would be strengthened. Whereas, if EPA continues to rank the lives of other nations' citizens far lower than our own (even as our historic greenhouse gas emissions lead to further climate crises that endanger and kill their citizens), such self-dealing, hypocrisy, and racism will alienate us from even our closest allies.

*Security and Immigration:* The Pentagon has ranked the climate emergency as the greatest threat to peace and global stability. Increased droughts and hunger will lead to more wars and threats to democracies worldwide. The more unlivable the global South becomes, the more the world and especially the U.S. will be overwhelmed with climate refugees, as we already are at our southern border. Setting a higher social cost of carbon will help us prevent the worst outcomes from occurring and keep us safer as a result.

*Economics:* A higher social cost of carbon could spur the development of new renewable energy technology or methods to remove carbon from the air, which the U.S. could then export to the rest of the world. Implementing a green economy faster will create even more jobs. Fewer climate catastrophes will preserve our economy whereas more climate disasters could slow, then sink it.

*Health:* Higher temperatures; dangerous weather events; smoke from forest fires; drought, species extinction, and consequent hunger; increased diseases spread by mosquitoes and other pests – these are just a few of the health dangers Americans face from global heating. A higher social cost of carbon would galvanize our nation to act more quickly to cut greenhouse gas emissions and avoid the worst of these outcomes, saving countless American lives.

Response II-20-56: A detailed response regarding the EPA's valuation of mortality risk when calculating the SC-GHG can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.



Comment: Commenter (2222-WDNR) states that while they do not anticipate the proposed rule will significantly decrease VOC emissions from sources in Wisconsin, several states that significantly contribute to ozone nonattainment or maintenance along the Lake Michigan shoreline have large oil and natural gas sectors. The commenter adds that the upwind VOC emissions reductions from this proposed rule may be significant and may improve Wisconsin's ability to attain and maintain ozone standards.

Response II-20-57: EPA acknowledges the supportive comment.

#### ***20.5.4 Hazardous Air Pollutant Impacts***

Comment: Commenter (2343-NYU School of Law) states that the EPA qualitatively discusses the co-benefits of HAP emissions reductions in the RIA and reports the total HAP emissions reductions expected from the December 2022 proposal, but it does not break those reductions down by individual pollutants or assign any monetary value to such figures.<sup>209</sup> As a result, the commenter believes that the EPA's estimate of total monetized benefits understates the health and environmental gains from the rule again. Even if EPA is currently unable to monetize the benefits of reducing HAP emissions, they suggest that it should strive to improve that capacity for its analysis of future regulations.

In the RIA's qualitative discussion of the HAP-related impacts, the commenter (2343-NYU School of Law) notes that the EPA explains that, "[w]ith the data available, it was not possible to estimate the change in emissions of each individual HAP," and that "methodology and data limitations" preclude "monetiz[ing] the health benefits of reductions in HAP."<sup>210</sup> As with VOCs, the commenter suggests that the EPA present any additional quantitative information available to it, such as the estimation of individual HAP reductions from the December 2022 proposal, even if incomplete or uncertain, and acknowledge any relevant limitations of that information.<sup>211</sup> In accordance with SAB's recommendation, EPA should prioritize estimating the HAP-related benefits associated with future regulations, as failing to do so leads to an underestimation of monetized benefits.<sup>212</sup> An assessment of HAP emission reductions for the December 2022 proposal and its alternatives, as compared to only a baseline discussion of HAP emission effects for the oil and gas industry, would provide more useful information for improving the distributional analysis to more fully examine effects on near-source communities.

Response II-20-58: We are currently unable to estimate or monetize the impact of changes in HAPs releases due to data limitations, most notably the lack of sufficient emission location specificity to perform such analyses. The HAP impacts available in EPA's 2017 AirToxScreen dataset are provided for the entire oil and natural gas sector, which includes sources outside the scope of this regulation. We do not have current modeling of HAP impacts specific to only the

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<sup>209</sup> Id. at 161–62 tbl.5-4 (estimating that the Supplemental Proposal would abate about 390,000 short tons of HAP emissions).

<sup>210</sup> Id. At 84–85.

<sup>211</sup> Circular A-4 (2003), *supra* note 10, at 27 ("If you are not able to quantify the effects, you should present any relevant quantitative information along with a description of the unquantified effects").

<sup>212</sup> SAB DRAFT REPORT, *supra* note 16, at 15.

sources subject to the regulation; therefore, we cannot estimate risks, including any reductions, solely attributed to the source category.

### ***20.5.5 Monetization of the Health and Ozone Benefits as a Result of Emissions Reductions***

Comment: Commenter (2343-NYU-School of Law) states that, in the RIA, EPA qualitatively discusses the co-benefits of VOC emissions reductions and reports the total VOC emissions reductions expected from the December 2022 supplemental proposal, but EPA does not assign any monetary value to these reductions except in Appendix C to the RIA.<sup>213</sup> As a result, the commenter contends that the EPA's estimate of total monetized benefits understates the health and environmental gains from the rule—most likely significantly. While appropriately recognizing the limitations and uncertainties underlying its calculations in Appendix C to the RIA, the commenter suggests that EPA discuss the magnitude of the monetized health benefits it estimates from reducing VOC emissions in its main regulatory analysis.

Commenter (2343-NYU-School of Law) expresses that the EPA discusses two categories of benefits associated with reducing VOC emissions: those related to ozone and those related to fine particulate matter (PM<sub>2.5</sub>).<sup>214</sup> EPA explains that, to calculate ozone impacts from changes in VOC emissions, it requires information about the spatial patterns in these emissions changes, and further, to estimate the ozone health effects from the December 2022 supplemental proposal it requires information on the relative proximity of expected VOC and ozone changes to population.<sup>215</sup> EPA explains that it “ha[s] not characterized VOC emissions changes at a finer spatial resolution than the national total due to data and resource constraints.”<sup>216</sup>

However, commenter (2343-NYU-School of Law) provides that in Appendix C, EPA presents an illustrative screening analysis of ozone-related health benefits based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017, but it does “not include the results of this screening analysis in the estimate of benefits (and net benefits) projected from this proposal.”<sup>217</sup> This analysis estimates that the combined monetized benefits of avoided morbidity health effects and avoided long-term ozone mortality would be \$7.2 billion between 2023–2035 (under a 3% discount rate).<sup>218</sup> While EPA acknowledges the various uncertainties and limitations of this calculation, the commenter notes that if it considers this to be an accurate representation of the rough magnitude of the benefits associated with VOC emission reductions, it should discuss its approximate size and significance in the main analysis while recognizing the relevant limitations.

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<sup>213</sup> RIA, *supra* note 3, at 161–62 tbl.5-4 (estimating that the Supplemental Proposal would abate about 9,700,000 short tons of VOC emissions).

<sup>214</sup> Id. at 79, 81–82. EPA explains that it does not monetize PM<sub>2.5</sub>-related benefits due to its need for air-quality monitoring and because “it is unlikely that the VOC emissions reductions projected to occur under this proposal would have a large contribution to ambient secondary organic carbon aerosols.” Id. at 82. Accordingly, this paragraph instead focuses on the ozone-related impacts.

<sup>215</sup> Id. at 79

<sup>216</sup> Id.

<sup>217</sup> Id.

<sup>218</sup> Id. at 208.

In the RIA's discussion of both ozone and PM<sub>2.5</sub>-related impacts of VOC emissions, the commenter (2343-NYU-School of Law) states that the EPA states that "in future regulatory impact analyses supporting other regulations, the EPA plans to account for the emissions impacts of the oil and natural gas [new source performance standards] and [existing source emissions guidelines] in the baseline for the analysis."<sup>219</sup> Given the magnitude of ozone health effects associated with VOC emissions, the commenter recommends that the EPA prioritize estimating the spatial distribution of VOC changes so that it might include a better monetized estimate of these health effects for relevant future rules.

Response II-20-59: EPA includes an analysis of the impact of changes in VOC releases via their impact on ozone formation in Section 3 of the final RIA. The monetized benefits associated with those changes in VOC are included in the main net benefits estimation.

Comment: Commenter (2343-NYU School of Law) recommends that EPA consider incorporating its estimate of the health benefits associated with reducing exposure to methane-related ozone into the social cost of methane.<sup>220</sup> If it chooses not to incorporate these effects into the social cost of methane, they suggest that EPA include these monetized impacts in its assessment of other costs and benefits in the RIA. The commenter suggests that failing to do so leads to significant underestimation of the benefits associated with the December 2022 proposal. Indeed, the commenter notes that the EPA's SAB draft report explains that published literature demonstrates that "the monetized value of this ozone-attributable health response is comparable to the climate-related social cost of methane, so that leaving out this impact leads to a large underestimate of the total benefits."<sup>221</sup>

The commenter (2343-NYU School of Law) explains that SAB notes that deriving a monetized estimate of the health benefits of reducing exposure to ozone via methane emissions reduction is not analytically dependent on precise modeling of the spatial distribution of methane emissions given "the relatively long (decadal) residence time of methane in the atmosphere."<sup>222</sup> The SAB advises that EPA can draw from published literature and the experience of scientists from EPA for estimating a monetized value.<sup>223</sup> This literature suggests that the value could be tens of billions of dollars in health benefits between 2023-2035.<sup>224</sup> Considering this, the commenter

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<sup>219</sup> Id. at 82.

<sup>220</sup> See Kevin R. Cromar et al., Global Health Impacts for Economic Models of Climate Change: A Systematic Review and Meta-Analysis, 19 ANNALS AM. THORACIC SOC. 1,203 (2022).

<sup>221</sup> SCIENCE ADVISORY BOARD OIL AND GAS CLIMATE RULE REVIEW WORKGROUP, SCIENCE ADVISORY BOARD REGULATORY REVIEW REPORT OF SCIENCE SUPPORTING EPA DECISIONS FOR THE PROPOSED RULE: STANDARDS OF PERFORMANCE FOR NEW, RECONSTRUCTED, AND MODIFIED SOURCES AND EMISSIONS GUIDELINES FOR EXISTING SOURCES: OIL AND NATURAL GAS SECTOR 14 (2023) (draft report), [https://sab.epa.gov/ords/sab/f?p=114:19:14980960002727::RP,19:P19\\_ID:982](https://sab.epa.gov/ords/sab/f?p=114:19:14980960002727::RP,19:P19_ID:982) (scroll to "Draft Report(s)" and click hyperlink below) (last visited Feb. 13, 2023) [hereinafter, SAB DRAFT REPORT].

<sup>222</sup> Id. at 14.

<sup>223</sup> Id.

<sup>224</sup> The United Nations Environment Programme estimates the monetized mortality effects due to ozone from methane emissions to be \$2,500 per metric ton of methane. UNITED NATIONS ENVIRONMENT PROGRAMME, GLOBAL METHANE ASSESSMENT: BENEFITS AND COSTS OF MITIGATING METHANE EMISSIONS (2021) <http://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane->

suggests that EPA heed the SAB's recommendation to monetize these benefits. If EPA believes it cannot provide these monetized benefits, they suggest that EPA should explain its reasoning.

Response II-20-60: The respiratory-related deaths associated with exposure to ozone produced from methane emissions are discussed in Section 3.7 of the Final RIA. In that section, EPA provides an illustrative calculation, based on recently published literature, of what the scale of the monetized benefits could be from this methane-ozone mechanism, but more work is required before incorporating those quantified benefits into the main net benefits analysis. Instead, EPA lists decreases in methane-related ozone resulting from the rule as unquantified benefits.

A detailed response regarding the omitted impact categories, including the health effects of methane-related ozone, from the SC-GHG estimates can be found in the Appendix of this RTC where responses are provided on comments pertaining to EPA's September 2022 *Draft Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.

Comment: Commenter (2293-Holmes) expresses that they were pleased to see the EPA's RIA document identify, in the Figure C-4 map, the Uinta Basin as a significant source of VOC-related ozone. They also expressed disappointment that the RIA did not provide an updated analysis of methane-related ozone impacts in the Uinta Basin and elsewhere. The commenter notes that the RIA admits that "[I]n remote areas, methane is a dominant precursor to tropospheric ozone formation."

The commenter (2293-Holmes) notes that the Uinta Basin is a remote area. Ozone is a very real problem there and bound to get worse absent active positive federal intervention. The RIA observes that ozone health effects include "asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality." It's no surprise, then, that healthcare clinics in Uinta Basin are advertising for more respiratory therapists. The commenter suggests that the RIA could have done a better job of investigating a leading oil and gas industry factor that is negatively impacting rural Utahns.

Response II-20-61: The respiratory-related deaths associated with exposure to ozone produced from methane emissions are discussed in Section 3.7 of the Final RIA. In that section, EPA provides an illustrative calculation, based on recently published literature, of what the scale of the monetized benefits could be from this methane-ozone mechanism, but more work is required before incorporating those quantified benefits into the main net benefits analysis. Instead, EPA lists decreases in methane-related ozone resulting from the rule as unquantified benefits.

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emissions. For illustrative purposes, if EPA used that number to estimate a lower-bound estimate (because it excludes morbidity effects), it would find that the Supplemental Proposal could generate approximately \$66.8 billion in health benefits from reduced ozone-related methane from 2023 to 2035. This calculation assumes EPA's estimated reductions in methane emissions due to the Supplemental Proposal (RIA *supra* note 3, at 162 tbl.5-4) of 36,000,000 short tons, converted to 32,658,649 metric tons, where the emissions reductions are distributed equally annually, and a 3 percent discount rate.

## 20.6 Environmental Justice Analysis

Comment: Commenter (2343-NYU School of Law) states that the EPA properly includes an environmental justice analysis in the RIA. But they recommend that EPA strengthen the distributional analysis to capture the distributional impacts of the Supplemental Proposal more fully. To further improve its analysis, they suggest that EPA look to recent scholarship, which has identified key features of meaningful distributional analysis.<sup>225</sup> They further urge EPA to consider the recommendations of its Science Advisory Board (SAB) on improving the environmental justice analysis for the Supplemental Proposal.<sup>226</sup>

The commenter (2343-NYU School of Law) recommends that EPA strengthen the consideration of distributional impacts in the Supplemental Proposal in five key ways: (1) estimate the distributional impacts of the Supplemental Proposal and its alternatives in addition to the baseline; (2) address data limitations and further quantify important impacts; (3) integrate consideration of cumulative environmental burdens on affected communities; (4) fully integrate the results of its analysis into its final decision; and (5) treat distributional effects like unquantified impacts in its decision-making. The commenter notes that these practices would be consistent with EPA’s Guidelines on Conducting Economic Analyses which clarify that “evaluating a program’s distributional effects is an important complement to benefit-cost analysis.”<sup>227</sup> By improving its distributional analysis, the commenter notes that EPA can improve its understanding of how to reduce harms to overburdened communities and fulfill its strategic goal to advance environmental justice.<sup>228</sup>

In the RIA, the commenter (2343-NYU School of Law) notes that the EPA conducts a baseline analysis, which identifies existing disparities in the populations exposed to emissions from the oil and gas source category through both qualitative and quantitative means. However, the commenter states that this baseline analysis, by its nature, does not analyze the distributional impacts of the Supplemental Proposal or its alternatives. Instead, EPA’s analysis finds, at a general level, that the current negative impacts of methane, HAP, and VOC emissions fall disproportionately on certain communities, and the agency accordingly believes that the Supplemental Proposal, by reducing these emissions in general, will improve health and welfare in these communities.

According to the commenter (2343-NYU School of Law), baseline understanding of disproportionate burdens created by the source category is helpful but should be accompanied by an analysis that evaluates the distribution of impacts resulting from the Supplemental Proposal and any incremental differences from adopting EPA’s proposed alternatives. Indeed, the

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<sup>225</sup> See, e.g., Richard L. Revesz & Burçin Ünel, Just Regulation: Improving Distributional Analysis in Agency Rulemaking (Inst. for Pol’y Integrity, Working Paper, 2022); Richard L. Revesz & Samantha P. Yi, Distributional Consequences and Regulatory Analysis, 52 ENV’T L. 53, 57 (2022); JACK LIENKE ET AL., INST. FOR POL’Y INTEGRITY, MAKING REGULATIONS FAIR: HOW COST-BENEFIT ANALYSIS CAN PROMOTE EQUITY AND ADVANCE ENVIRONMENTAL JUSTICE (2021); Richard L. Revesz, Regulation and Distribution, 93 N.Y.U. L. REV. 1489, 1492 (2018); see also Caroline Cecot & Robert W. Hahn, Incorporating Equity and Justice Concerns in Regulation, REGUL. & GOVERNANCE (2022).

<sup>226</sup> SAB DRAFT REPORT, *supra* note 16, at 15–19.

<sup>227</sup> EPA ECONOMIC ANALYSIS GUIDELINES, *supra* note 37, at 10-1.

<sup>228</sup> See, e.g., EPA, FY 2022–2026 EPA STRATEGIC PLAN 32–34 (2022), <https://perma.cc/3YXC-ZUAB>.

commenter notes that President Biden’s Memorandum on Modernizing Regulatory Review calls for analysis of “distributional consequences . . . to ensure that regulatory initiatives appropriately benefit and do not inappropriately burden disadvantaged, vulnerable, or marginalized communities.” To fully assess how the rule will affect environmental justice community health and welfare, the commenter recommends that the EPA analyze the distributional consequences of the Supplemental Proposal.

In addition, the commenter (2343-NYU School of Law) recommends that EPA analyze the distributional implications of each alternative—consistent with Circular A-4 (2003)’s guidance that “‘an examination of alternative approaches’ [is] one of the three basic elements of ‘a good regulatory analysis.’”<sup>229</sup> This analytical step is a natural extension of EPA’s existing alternatives analysis, which already assesses the costs and benefits of a more stringent alternative and a less stringent alternative.<sup>230</sup> By considering alternatives in its assessment of distributional impacts, EPA would be better able to weigh not only the respective net benefits, but also the distribution of costs and benefits when comparing alternatives. If the distribution of impacts under one alternative is desirable enough—for example, because it increases the health and safety of already unfairly overburdened communities—that may justify selecting that alternative over one with greater net benefits but a less desirable distribution of impacts.

The commenter (2343-NYU School of Law) notes that the EPA has several potential ways to apply these long-standing directives to consider distributional effects. One way is to treat desirable (or undesirable) distributional effects as unquantified benefits (or costs) that it compares alongside other costs and benefits.<sup>231</sup> This comparison would mean valuing distributional impacts similarly to any other unquantified cost or benefit in its analysis. In this way, the agency can understand the tradeoffs in scenarios in which the value of achieving certain distributional goals merits leaving at least some net benefits on the table. Again, this is consistent with the treatment of unquantified effects. EPA, like other agencies, is expected to weigh unquantified effects against monetized costs and benefits in accordance with its judgment and expertise.<sup>232</sup>

The commenter (2343-NYU School of Law) adds that the EPA has a long history of considering unquantified effects, including in the Supplemental Proposal, where EPA has explained that many benefits were unable to be quantified.<sup>233</sup> EPA guidance is also clear that EPA should consider unquantified costs and benefits in its analysis.<sup>234</sup> In cases, with “potentially important effects that cannot be quantified, the analyst should include a qualitative discussion of benefits results” and that “discussion should explain . . . the reasons for believing that these non-

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<sup>229</sup> Revesz & Yi, *supra* note 41, at 64 (quoting Circular A-4 (2003), *supra* note 10, at 2).

<sup>230</sup> See RIA, *supra* note 3, at 55–59.

<sup>231</sup> See Revesz & Yi, *supra* note 41, at 96–97 (discussing why this approach should be preferred).

<sup>232</sup> See *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 235 (2009) (Breyer, J., concurring in part and dissenting in part) (writing approvingly of EPA’s ability to “describe environmental benefits in non-monetized terms and to evaluate both costs and benefits in accordance with its expert judgment and scientific knowledge”).

<sup>233</sup> RIA, *supra* note 3, at 10, 60.

<sup>234</sup> EPA ECONOMIC ANALYSIS GUIDELINES, *supra* note 37, at 7-49.

quantified effects may be important for decision making.”<sup>235</sup> EPA should apply the same treatment to distributional effects.

Additionally, the commenter (2343-NYU School of Law) recommends that EPA coordinate internally and externally with other agencies and with OMB to conduct its distributional analysis for this rule in a manner that contributes to achieving a standardized approach to distributional analysis across the federal government.

Additional comments relating to the use of OMB Circular A-4 (2003) are presented in section 22.1.2 of this Chapter.

Response II-20-62: The EPA agrees with the commenters that a strengthened distributional analysis of both baseline and the policy option is important to perform when feasible to do so. Due to the availability of new ozone spatial surfaces that reflect the policy option’s estimated air pollution changes, EPA was able to add an expanded distributional EJ analysis to the final RIA that assesses the distributional impacts of both the baseline and the policy option. In addition, new population subgroup variables have been added to the analysis to better capture cumulative risks, most notably, the life expectancy variable which serves as a proxy to identify communities with exposure to more risks over the course of their lifetime that lead to a lower life expectancy on a community-level. EPA believes that these improvements to the environmental justice analysis better reflect the Circular A-4 (2003) and Circular A-4 (2023) Guidance and the recent Executive Orders on environmental justice that direct analysts to more thoroughly consider the distributional impacts of proposed policy.

Comment: Commenter (2392-Earthjustice et al) states that, in line with EPA Guidance, the RIA for the Supplemental Proposal analyzes environmental justice impacts as categorized by demographic groups.<sup>236</sup> This commenter notes that they take a different approach, instead analyzing first some of the impacts associated with oil and gas infrastructure and pollution,<sup>237</sup> and thereafter integrating demographic specific data and experiences. The commenter notes that they utilize this approach to emphasize that adverse health, economic, and climate vulnerability impacts are commonly experienced across communities.

Response II-20-63: EPA acknowledges the commenter’s clarifications.

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<sup>235</sup> Id.

<sup>236</sup> See U.S. Env’t Prot. Agency, Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review at 106-36 (2022), <https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-eg-climate-review-updated.pdf>.

<sup>237</sup> Joint Environmental Justice Commenters note that this comment letter does not contain a comprehensive recitation of the disparate impacts that oil and gas development and pollution have on low-income communities and communities of color. Rather, this provides numerous examples of how the oil and gas industry has outsized impacts on these communities.

Comment: Commenters (2393-ODEQ/OSSE) report that staff performed a review of the RIA<sup>238</sup> for the November 2021 Proposal as well as the RIA for the SNPR.<sup>239</sup> A longer review time was needed to allow adequate review of the SNPR RIA due to the complexity of the SNPR and the associated documents. However, the commenters state that, as was the case for the November 2021 Proposal and stated in their 2021 Comments, they found the approach taken in the RIA for the SNPR to be inadequate. Further, they add that it does not appear that EPA sufficiently addressed the issues raised in their 2021 Comments. The commenters suggest that there are still details that warrant a more rigorous analysis by EPA.

The commenters (2393-ODEQ/OSSE) state that one issue of concern is the lack of any detailed projections of likely reductions in oil and gas employment. While there are economic projections showing impacts on future oil and gas prices and production, there does not appear to be a concrete projection of the reduction in employment that would likely be associated with adoption of the proposed regulations. This is particularly concerning in Oklahoma due to the number of marginal wells that remain in operation and whose financial viability may be precarious. Further, the commenters add that the jobs in the oil and gas sector are particularly well-paying when compared to alternatives, especially in rural areas and, because job losses are likely to be localized, the effects are magnified in those communities.

The commenters (2393-ODEQ/OSSE) note that the SNPR RIA, beginning on page 126, explains the baseline approach used to evaluate employment impacts in Section 4 of the RIA:

The EPA also conducted a baseline analysis to characterize potential distributional impacts on employment. A reduction in oil and natural gas activity could have a negative effect on employment among oil and natural gas workers. This could also reduce employment, earnings, and tax revenues in oil and natural gas intensive communities.<sup>95</sup> Any effect on oil and natural gas workers or oil and natural gas intensive locations would be a local and partial equilibrium effect. In general equilibrium, there could be other and potentially offsetting effects in other regions and sectors.

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Comparing workers in the oil and natural gas sector to workers in other sectors, oil and natural gas workers may have higher than average incomes, be more likely to have completed high school, and be disproportionately Hispanic. People living in some oil and natural gas-intensive communities concentrated in Texas, Oklahoma, and Louisiana, may have disproportionate income levels, rates of high school completion, and demographic composition.

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<sup>238</sup> U.S. EPA, “Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” (RIA), EPA-452/R-21-003, October 2021 ([https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review\\_0.pdf](https://www.epa.gov/system/files/documents/2021-11/proposal-ria-oil-and-gas-nsps-eg-climate-review_0.pdf)).

<sup>239</sup> U.S. EPA, “Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” (RIA), EPA-452/R-22-007, November 2022 (<https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-eg-climate-review-updated.pdf>).



The commenters (2393-ODEQ/OSSE) state that this information appears unchanged from the RIA for the November 2021 Proposal and lends support to the contention that the economic impacts of this rulemaking will likely be significantly harmful to rural communities dependent on this industry. It is with this concern in mind that the commenters again recommend that EPA consider economic impacts of this rulemaking with the same level of granularity and diligence that was used in evaluating the rulemaking's benefits for environmental justice communities. The importance of oil and gas jobs is further emphasized by the information in Table 4-8 of the SNPR RIA which shows that the average income for oil and natural gas workers is \$110,000 while the average income for other workers in "oil and gas communities" is \$42,000. Thus, for every oil and gas job lost, even if there is a new non-oil and gas job created in the same community, they report that there will be a net loss of \$68,000 with additional spillover effects in the community.<sup>240</sup>

The commenters (2393-ODEQ/OSSE) cite Page 128 of the December 2022 supplemental notice of proposed rulemaking RIA that sets forth data used to develop the analysis:

This analysis uses 5-year ACS data from 2015-2019 retrieved from IPUMS. This is approximately 16 million individual ACS responses. Oil and natural gas workers are identified by working in industries with a NAICS code that begins with "211." Those are "Oil and natural gas Extraction," as well as the sub-industries "Crude Petroleum Extraction" and "Natural Gas Extraction."

Response II-20-64: EPA acknowledges the challenge in assessing the employment impacts of the regulation. To the extent that regulatory costs lead to reduced production, sector employment could be reduced, though this is not guaranteed as firms could simultaneously reallocate expenditures on productive inputs away from capital and towards labor because of the regulation. In addition, as noted by some commenters, the regulation may also increase employment by increasing the demand for compliance-related labor. The net effect is ambiguous without sufficient data, which hasn't been provided by commenters.

Comment: Commenter (2393-ODEQ/OSSE) remains concerned that EPA's analysis is too vague and broad-brush. The commenter believes that the rule would, if adopted, undermine EPA's goal of expanding environmental justice.

The commenter (2393-ODEQ/OSSE) states that jobs in the oil and natural gas sector are engines of Oklahoma's rural economy.<sup>241</sup> In rural Oklahoma, issues of environmental justice are closely tied to the success of the oil and natural gas industry. The commenter contends that any policy that undercuts employment in the oil and natural gas sector will harm the economic foundation

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<sup>240</sup> In the original RIA, the average income for oil and natural gas workers was the same as in the SNPR RIA (\$110,000); in the SNPR RIA, the average income for other workers increased from \$40,000 to \$42,000.

<sup>241</sup> See, for example, the article, "Feeling the Pain: In Rural Oklahoma, Oilfield Communities See the Ups and Downs of Oil and Gas Industry Firsthand," by Cody Bannister, February 11, 2021, available online: <https://www.thepetroleumalliance.com/feeling-the-pain-in-rural-oklahoma-oilfield-communities-see-the-ups-and-downs-of-oil-and-gas-industry-first-hand/>.

of rural Oklahomans. In fact, they note that even the New York Times recently published an article acknowledging that:

People of color make up 24 percent of the rural population. Close to half of rural Native Americans and more than half of rural Black Americans live in a distressed county. That's compared with 18 percent of rural whites. Anyone serious about racial equity must also be serious about rural America.<sup>242</sup>

The commenter (2393-ODEQ/OSSE) notes that EPA has not made or documented important inquiries, such as how many marginal wells are expected to close as a result of the proposed rules, how many jobs are expected to be lost, and which communities are likely to experience those losses. It may be challenging to attempt to address these issues with sufficient rigor, but an attempt is certainly warranted to justify policies that will have disproportionate impacts on some communities to benefit the entire public. The commenter supports the evaluation of environmental impacts on environmental justice communities, however, they believe that the EPA's preliminary analysis does not account for the full range of this rulemaking's potential impacts and could result in unintended consequences for communities dependent on oil and gas economies, which could include overlooked environmental justice communities.

Further, the commenter (2393-ODEQ/OSSE) states that the December 2022 proposal includes policies that, if adopted as proposed, would worsen the concerns raised in the commenter's November 2021 comments. The commenter explains that the requirement that all existing wells undergo annual fugitive emissions monitoring (with no exemption for older, lower-producing wells) will likely render many of those older wells too expensive to operate resulting in job losses in older, rural communities that are not currently seeing new oil and natural gas exploration activities. The commenter believes that low-income rural communities are experiencing many negative socio-economic problems that will only be exacerbated if the December 2022 proposal is adopted.

In addition, the commenter (2393-ODEQ/OSSE) believes that the proposed super-emitter response program runs the risk of privileging wealthier communities (or well-supported environmental advocacy organizations) at the expense of marginalized communities and smaller, less well-resourced oil and natural gas companies. The commenter contends that wealthier communities are more likely to hire expensive consultants to ensure they are equipped with the latest and most expensive technology. They add that well-resourced environmental advocacy organizations can observe activities in hot spots or areas of concern to their donor base, but those observations may not be well-evidenced due to a lack of expertise. The commenter believes that smaller oil and natural gas operators may be inundated with frivolous complaints from individuals or organizations with resources but not necessarily the expertise to set forth credible claims.

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<sup>242</sup> "A Policy Renaissance Is Needed for Rural America to Thrive," by Tona Pipa (Senior Fellow at the Center for Sustainable Development at the Brookings Institution and leader of the Reimagining Rural Policy Initiative), from the New York Times, online, published December 27, 2022, <https://www.nytimes.com/2022/12/27/opinion/rural-america-left-behind-places.html>.

Response II-20-65: In response to the commenter, EPA developed a financial analysis of marginal oil and natural gas wells in Chapter 6 of the Final Rule TSD. EPA finds that marginal wells may continue to operate at low or negative profits rather than be shut-in and plugged due to a variety of reasons, including low operating costs, high plugging costs, low state bonding requirements, accounting practices, and tax credits available to the oil and gas industry. With the available data and the complexity described, EPA cannot estimate the impacts of the final regulation on the owners or operators of marginal wells and is not able to offer an estimate of how many wells would be plugged, if any.

Comment: Commenters (2254-PBPA, 2257-MOGA, 2304-PIOGA, 2393-ODEQ/OSEE, 2447-Clean Air for the Long Haul) urge EPA to expand the economic impact analysis on small rural “underserved or overburdened communities”.

Commenter (2257-MOGA) reminds EPA that many of these “underserved or overburdened communities” are often located in rural areas where oil and gas drilling and production provide jobs and sustains local economies. The commenter expresses concern that the proposed rules will likely result in the early plugging of marginal wells that cannot absorb the initial implementation and ongoing costs of the proposed regulation, directly impacting associated small businesses, including hotels, restaurants, service, retail and other “mom and pop” stores that rely on the oil and gas industry to survive.

Commenter (2393-ODEQ/OSEE) expresses concern that the December 2022 proposal does not provide fair consideration of the economic impacts in distressed rural communities that may not meet EPA’s threshold of “environmental justice community.” The commenter finds that the December 2022 proposal would do additional damage to communities that rely heavily on oil and gas employment, especially those located in rural parts of Oklahoma. The commenter strongly encourages EPA to broaden its evaluation of the costs and benefits of this rulemaking to incorporate economic effects with the same level of granularity that was used in targeting communities living in proximity to facilities that would be subject to this rulemaking. The commenter notes that, in particular, EPA has not adequately examined how these policies will affect employment in economically distressed rural communities in states like Oklahoma. In order to ensure that just policies are adopted, the commenter recommends that EPA reconsider the December 2022 proposal and allocate time and resources to properly weigh the economic impacts on vulnerable communities, especially rural communities, as carefully as the environmental benefits are evaluated.

The commenter (2393-ODEQ/OSEE) references a study by Price Waterhouse that was performed for the American Petroleum Institute, which determined that the oil and gas sector was responsible (including direct and indirect employment) for 16.7 percent of the Oklahoma workforce.<sup>243</sup> The commenter adds that many oil and gas jobs employ residents of rural

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<sup>243</sup> “Impacts of the Oil and Natural Gas Industry on the US Economy in 2019,” prepared by PricewaterhouseCoopers LLP, prepared for the American Petroleum Institute, July 2021, available on-line: <https://www.api.org/-/media/Files/Policy/American-Energy/PwC/API-PWC-Economic-Impact-Report.pdf>.

communities.<sup>244</sup> To assess the possible impacts of job losses in those communities, the work performed by the U.S. Department of Agriculture's (USDA's) Economic Research Service investigated economic, social, and demographic factors that affect the poverty status of residents of rural communities. The commenter notes that for 2019, the USDA estimated Oklahoma's statewide poverty rate at 15.1 percent with 19.7 percent of Oklahoma's children living in poverty.<sup>245</sup> Rural counties, especially in the southeastern part of the state are particularly impacted by poverty.<sup>246</sup> The commenter explains that the availability of middle-class oil and gas jobs in rural Oklahoma mitigates the poverty experienced in many of these communities.

The commenter (2393-ODEQ/OSEE) expresses concern that the data set EPA used was exclusively from the oil and gas extraction segment and does not appear to include the drilling, treatment, storage, or transmissions segments. Further, both the RIA for the November 2021 Proposal and the SNPR RIA used Public Use Microdata Area (PUMA) data to identify oil and gas communities. The commenter contends that this level of analysis is insufficiently specific in identifying impacts on rural areas. This assertion is demonstrated by the map (Figure 4-9 on p. 129 of the SNPR RIA) which shows the relatively large size of each PUMA. In addition, they note that the oil and gas PUMAs shown in the map cover more than half the state of Oklahoma. In contrast, the environmental justice communities in EJScreen<sup>247</sup> are identified with much finer granularity. The commenter questions whether and to what degree this analysis inherently biases the evaluation of costs and benefits, thereby possibly privileging certain communities compared to others.

The commenter (2393-ODEQ/OSEE) notes that Table 4-9 in the December 2022 proposal RIA provides demographic data for the entire group of PUMAs with high oil and gas intensity. This analysis is used to draw various conclusions concerning the ethnic make-up, educational attainment, and income of residents in these areas compared with other areas with lower oil and gas intensity. By aggregating the high oil and gas PUMAs for these analyses, the commenter states that EPA fails to give a sufficiently granular analysis of the impacts of the types of rural communities found in Oklahoma. The commenter contends that this contrasts with EPA's approach in evaluating impacts on environmental justice communities.

According to the commenter (2393-ODEQ/OSEE), while the analysis in the December 2022 proposal RIA (see Table 4-10 and Figure 4-10 of the December 2022 proposal RIA) provides some greater specificity, the commenter believes it is still insufficient and fails to meet the standards EPA uses for evaluating environmental justice communities. Notable in Figure 4-10 of the December 2022 proposal RIA is just how large a fraction of the state of Oklahoma is included in the PUMAs evaluated.

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<sup>244</sup> See, for example, the article "Feeling the Pain: In Rural Oklahoma, Oilfield Communities See the Ups and Downs of Oil and Gas Industry Firsthand," by Heidi Brandes, February 11, 2021, available on-line on the web page of The Petroleum Alliance: <https://www.thepetroleumalliance.com/feeling-the-pain-in-rural-oklahoma-oilfield-communities-see-the-ups-and-downs-of-oil-and-gas-industry-first-hand/>.

<sup>245</sup> U.S. Department of Agriculture, Economic Research Service, Rural Poverty & Well-Being, state poverty rate data available on-line: <https://data.ers.usda.gov/reports.aspx?ID=17826>.

<sup>246</sup> County data are available from the link cited in Footnote 5 by selecting "Oklahoma."

<sup>247</sup> See <https://www.epa.gov/ejscreen>.

Commenter (2254-PBPA) recommends that EPA evaluate the impact of the proposed rule on the economically disadvantaged. The commenter states that the EPA properly acknowledges “[t]his action, which is a significant regulatory action under Executive Order 12866, has a significant adverse effect on the supply, distribution or use of energy.” Inevitably, the commenter notes that this rule will have a direct impact on consumers. The commenter believes that chilling domestic production will do nothing to address consumer demand for fuels and will likely increase fuel prices resulting in additional inflation on the prices of consumer goods as it becomes more expensive to manufacture and transport basic goods.

The commenter (2254-PBPA) states that it is not clear that the EPA has fully considered or discussed the environmental justice implications of the increased cost of production that will result from implementation of the proposed rule. The commenter recommends that EPA evaluate the impact of the proposed rule on the economically disadvantaged who must devote a greater portion of their limited budgets to items such as energy costs. The commenter explains that these consumers cannot readily reduce their home heating/cooling or transportation needs. The commenter notes that EPA’s Regulatory Impacts Analysis (RIA) notes that EPA didn’t do any regional modeling to determine if people living in poorer conditions would suffer from reduced hydrocarbon production. As the EPA points out, oil and gas prices are inelastic, which means if the U.S. cannot produce oil and gas, other countries will. The commenter asserts that production forced overseas leads to an increased cost for American consumers. According to the commenter, such increases tend to have a disproportionate impact on economically disadvantaged communities.

Commenter (2304-PIOGA) asserts that EPA has failed to consider or evaluate the proposal impact on communities that rely on the conventional oil and natural gas industry. The commenter contends that any requirements associated with enhanced community involvement must be balanced, i.e., EPA and the states should be just as focused on the benefits the industry brings to the community as they are on potential negative ramifications.

The commenter (2304-PIOGA) notes that the December 2022 supplemental proposal would require states to engage in enhanced community engagement with the laudable intent of engaging communities that have historically been disenfranchised and perhaps disproportionately impacted negatively by "industry." The commenter contends that any requirements placed on the states related to enhanced community engagement need to understand and account for the positive impacts of the oil and natural gas industry in rural communities. The commenter reports that often, the oil and natural gas industry, particularly the conventional, or low production, well portion of the industry, is the primary, if not only economic driver for the region. In most situations, the landowner where the well is drilled is provided "free gas" or "house gas". Often the landowner is provided a certain royalty associated with the gas that is removed from the property. The commenter states that in the case of low production wells, the economic benefit to the landowner may not appear to be much, but in the end, it could be the difference between "selling the farm" and not. Additionally, the commenter notes that certain rural communities are not served by "big oil" or unconventional natural gas wells and interstate pipelines. Without the conventional low production wells, families would lose the ability to utilize natural gas to heat their homes and/or run their business and would have to rely upon energy sources with greater emissions than natural gas.

Commenter (2447-Clean Air for the Long Haul) states EPA estimates abandoned wells emitted 263,000 metric tons of methane in 2019.<sup>248</sup> However, other research has shown there is an underestimation.<sup>249</sup> Apart from contributing significantly to climate change, these wells pose environmental, health, and safety hazards.<sup>250</sup> While an estimated 9 million people live in the vicinity of 81,000 inactive and unplugged orphan wells with no owner of record,<sup>251</sup> It is people of color who are most exposed to these threats as in the case of environmental justice communities in California.<sup>252,253</sup> It is crucial that a proximity analysis of abandoned and unplugged wells in relation to disadvantaged communities where more stringent monitoring and enforcement should occur and ensure that owners and operators of these wells take necessary remedial actions outlined in submitted closure plans to properly plug and prevent methane leaks.

Response II-20-66: EPA acknowledges the challenge in assessing the employment impacts of the regulation. To the extent that regulatory costs lead to reduced production, sector employment could be reduced, though this is not guaranteed as firms could simultaneously reallocate expenditures on productive inputs away from capital and towards labor because of the regulation. In addition, as noted by some commenters, the regulation may also increase employment by increasing the demand for compliance-related labor. The net effect is ambiguous without sufficient data, which hasn't been provided by commenters. EPA further assesses that the spatial scale of the analysis is appropriate for consideration of employment impacts. Smaller spatial units would not be appropriate because they would omit consideration of inter-county economic relationships including commuting by industry workers as well as indirect effects. Recent research finds economic impacts in both producing counties and the surrounding region.<sup>254</sup>

With respect to commenters' assertions regarding small businesses and low production wells, see Response II-20-34. With respect to commenters' assertions regarding commodity prices and household energy burden, see Response II-20-27.

In response to commenter that requests that the EPA require a proximity analysis of abandoned and unplugged wells in relation to disadvantaged communities where more stringent monitoring

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<sup>248</sup> EPA (2021). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, <https://www.epa.gov/ghgemissions/inventory-usgreenhouse-gas-emissions-and-sinks-1990-2019>.

<sup>249</sup> Groom, N (2020), "Special Report: Millions of abandoned oil wells are leaking methane, a climate menace," Reuters, <https://www.reuters.com/article/us-usa-drilling-abandoned-specialreport/special-report-millions-of-abandoned-oil-wells-are-leaking-methane-a-climate-menace-idUSKBN23N1NL>.

<sup>250</sup> Groom, N (2020), "Special Report: Millions of abandoned oil wells are leaking methane, a climate menace," Reuters, <https://www.reuters.com/article/us-usa-drilling-abandoned-specialreport/special-report-millions-of-abandoned-oil-wells-are-leaking-methane-a-climate-menace-idUSKBN23N1NL>.

<sup>251</sup> Environmental Defense Fund (2021), Documenting Orphan Wells Across the United States, <https://www.edf.org/orphanwellmap>.

<sup>252</sup> Ehlers, H., "Quantifying the Problem and Risks of Poorly Abandoned Oil and Gas Wells in Ventura County, California." Capstone Projects - Politics and Government, May 26, 2022, <https://uir.library.illinoisstate.edu/cppg/40>.

<sup>253</sup> Srebotnjak, T, and Rotkin-Ellman, M. (2014) Drilling in California: Who's at Risk? Natural Resources Defense Council, <https://www.nrdc.org/sites/default/files/california-fracking-risks-report.pdf>

<sup>254</sup> Black, K. J., Boslett, A. J., Hill, E. L., Ma, L., & McCoy, S. J. (2021). Economic, environmental, and health impacts of the fracking boom. *Annual Review of Resource Economics*, 13, 311-334.

and enforcement should occur, in response to comments on the November 2021 Proposal, the EPA did not propose any requirements for these sources in the December 2022 Supplemental Proposal. The EPA is finalizing well closure requirements, but no requirements are being finalized for abandoned wells, unplugged wells, or wells that are plugged insufficiently. As stated in section X.A (Fugitive Emissions from Well Sites, Centralized Production Facilities, and Compressor Stations) of the final preamble, EPA is finalizing well closure requirements under the fugitives monitoring requirements for actively producing wells. The final well closure requirements will prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair. See RTC Volume II Chapter 4, section 4.1.6 (Well Closure Requirements) for response to comments on the well closure plan associated with the fugitive monitoring requirements. See 40 CFR 60.5397b(l) of NSPS OOOOb and 40 CFR 60.5397c(l) of EG OOOOc for the final well closure requirements. Comment: Commenter (2392-Earthjustice) states that low- income communities and communities of color are disproportionately left with economic burdens resulting from oil and gas development, while the wealth created by this development is exported out of the communities where resource extraction occurs. The commenter highlights the disparate economic impacts associated with oil and gas production as they are experienced by Latin, rural, and low-income communities.

The commenter (2392-Earthjustice) notes that EPA’s economic environmental justice analysis in the RIA focused on the narrow issue of household energy expenditures and potential disparate impacts of increased cost due to regulation. However, as is demonstrated below, the adverse economic impacts associated with oil and gas production are broader than potential increases in energy costs. An accurate accounting of the economic impacts should consider the distribution of economic benefits and burdens, and their cumulative effects on impacted communities.

The commenter (2392-Earthjustice) believes, and multiple studies have found, that the local economic benefits of oil and gas production are overstated. A 2012 study of the local economic benefits associated with natural gas production across counties in Colorado, Texas, and Wyoming found that natural gas production had “modest” effects on employment and income, and that “ex-ante estimates of the number of jobs created by developing the . . . Marcellus shale gas formation[] may have been too large.”<sup>255</sup> Likewise, a 2014 study analyzing labor market conditions at the county level in nine states found only a “modest” impact on local employment and wage effects.<sup>256</sup>

Furthermore, the commenter (2392-Earthjustice) reports that research shows that much of the wealth generated by oil and gas production leaves the communities where extraction takes place. A 2015 study analyzed the distribution of economic costs and benefits associated with shale gas development in Denton, Texas.<sup>257</sup> The study found that “residents own[ed] 1 percent of the total

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<sup>255</sup> Jeremy Weber, The Effects of a Natural Gas Boom on Employment and Income in Colorado, Texas, and Wyoming, 34 Energy Econs. 1580, 1580 (2012), <https://pubag.nal.usda.gov/download/56362/pdf>.

<sup>256</sup> Jason Brown, Production of Natural Gas From Shale in Local Economies: A Resource Blessing or Curse?, Econ. Rev., Jan. 2014, at 119, 120, [https://www.kansascityfed.org/Economic%20Review/documents/1621/Production\\_of\\_Natural\\_Gas\\_From\\_Shale\\_in\\_Local\\_Economies\\_A\\_Resource\\_Blessing\\_or\\_CurseD4.pdf](https://www.kansascityfed.org/Economic%20Review/documents/1621/Production_of_Natural_Gas_From_Shale_in_Local_Economies_A_Resource_Blessing_or_CurseD4.pdf).

<sup>257</sup> Matthew Fry et al., Fracking and Environmental (In)justice in a Texas City, 117 Ecological Econs. 97, 97 (2015), <https://omeka.library.unt.edu/files/original/1f215096dd897cc492c3b94c157724a297193ccf.pdf>.

value extracted” from approximately 280 active gas wells between 2002 and 2013.<sup>258</sup> After analyzing the distribution of costs and benefits, the study concluded that “there is a disproportionate distribution of [shale gas development]’s burdens and benefits in Denton, with non-mineral owners paying the environmental and health risks without receiving direct economic benefits and others reaping the benefits without being exposed to the risks.”<sup>259</sup>

Response II-20-67: EPA calculates distributional impacts beyond household energy expenditures. In Section 4.3 of the RIA, EPA quantitatively or qualitatively considers disparate climate change and ozone impacts, air toxics impacts, and employment and related local production value impacts. In contrast to the commenter’s claim, EPA finds that oil and gas producing communities have similar proportions of Hispanic residents and similar incomes to the rest of the country.

EPA notes that recent studies find that oil and gas production is associated with substantial employment in both producing and nearby counties, and that a large share of the associated royalty payments go to leaseholders in the same county as the lease. EPA acknowledges that some specific communities’ resource rights may largely be held by non-residents.<sup>260</sup>

EPA is unable to estimate location-specific employment impacts of the Rule. EPA considers potential disparate impacts in Section 4.3 of the RIA including potential disparate impacts in climate impacts, ozone impacts, air toxics, employment effects, and energy price changes. EPA is unable to calculate changes in wealth generated by oil and gas production by income group.

Comment: Commenter (2392-Earthjustice et al) states that communities of color are disproportionately located near flaring sites. A recent study analyzed demographics in three basins—the Permian, Western Gulf (Eagle Ford Shale), and Williston (Bakken shale)—that account for 83% of unconventional oil and gas flaring in the U.S. from 2012 to 2020.<sup>261</sup> The commenter notes that the study unequivocally concluded that “[b]lack, indigenous, and people of color [are] disproportionately exposed to flaring.”<sup>262</sup> Analyzing the Permian and Western Gulf basins, the study found that “Blacks were more likely to live within 5 [kilometers] of a flare . . . than other groups.”<sup>263</sup> Likewise, the analysis of the Williston basin found that “Native American and Hispanic populations were the most likely to live near flares.”<sup>264</sup>

The commenter (2392-Earthjustice et al) adds that these findings are reflected in the experiences of Indigenous communities residing on the Fort Berthold Indian Reservation in North Dakota. The Reservation is home to the three affiliated tribes of the Mandan, Hidatsa, and Arikara (MHA

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<sup>258</sup> Id. at 97.

<sup>259</sup> Id. at 104.

<sup>260</sup> Black, K. J., Boslett, A. J., Hill, E. L., Ma, L., & McCoy, S. J. (2021). Economic, environmental, and health impacts of the fracking boom. *Annual Review of Resource Economics*, 13, 311-334.

<sup>261</sup> Lara J. Cushing et al., Up In Smoke: Characterizing the Population Exposed to Flaring From Unconventional Oil and Gas Development in the Contiguous US, 16 *Env’t Rsch. Letts.* 034032, 1 (2001), <https://pubs.acs.org/doi/abs/10.1021/acs.est.8b05355> [hereinafter “Cushing et al., Characterizing Populations Exposed to Flaring”].

<sup>262</sup> Id.

<sup>263</sup> Id. at 7.

<sup>264</sup> Id.



Nation) and once encompassed fertile agricultural lands along the Missouri River.<sup>265</sup> But the U.S. Army Corps of Engineers' construction of the Garrison Dam in the 1940s flooded significant portions of the Reservation, forcing residents to move into the higher badlands where agricultural development was not possible.<sup>266</sup> The MHA Nation then became reliant on oil and gas development for much needed revenues.<sup>267</sup> [Comment letter includes figure depicting George Gillette, chairman of the Fort Berthold Indian Tribal Council, weeping as the Secretary of the Interior signs an agreement forcing the MHA Nation to sell lands for the Garrison Dam.]

Commenter (2392-Earthjustice et al) states that with this development came significant adverse impacts on Reservation residents. In 2019, North Dakota accounted for 38% of the nation's vented and flared natural gas,<sup>268</sup> and an outsized portion of that flaring now happens on the Fort Berthold Reservation. From 2012 to 2020, nearly 20% of all flaring in North Dakota occurred on the Fort Berthold Reservation.<sup>269</sup> McKenzie county, which includes part of the Reservation, has the most flares of any county nationally, and virtually all the residents of this county live within 5 kilometers (about 3.2 miles) of more than 100 flares.<sup>270</sup> A 2018 analysis also found that people living on the Fort Berthold Reservation are 2 times more likely to live within a half-mile of an oil and gas facility, compared to the rest of North Dakota.<sup>271</sup>

Before they used to say that in North Dakota, you can see a dog run away for days. You look at the Bakken oil patch, and you see all the orange [from flaring]. They say you can see it from the space station. It looks like a Christmas tree, all the orange.

- Delvin Rabbithead, president of Fort Berthold Protectors of Water and Earth Rights.

Response II-20-68: EPA acknowledges the comment.

Comment: Commenter (2303-NTAA) notes that methane emissions disproportionately burden indigenous communities. For example, the Navajo Nation has 65% higher methane emissions from oil and gas companies than the national average.<sup>272</sup> The commenter cites a recent analysis by Environmental Defense Fund and Taxpayers for Common Sense found that indicates that oil

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<sup>265</sup> Jeremy Deaton, A Tribal Nation Dependent on Fossil Fuels Was Left in the Cold When the Pandemic Hit, The Hill (Apr. 22, 2021), <https://thehill.com/changing-america/sustainability/environment/549731-a-tribal-nation-dependent-on-fossil-fuels-was/>.

<sup>266</sup> Id.

<sup>267</sup> Id. (explaining that the MHA Nation earns 90% of its revenue from royalties and taxes on oil and gas development).

<sup>268</sup> Emily Geary, U.S. Energy Info. Admin., Natural Gas Venting and Flaring in North Dakota and Texas Increased in 2019 (Dec. 8, 2020), <https://www.eia.gov/todayinenergy/detail.php?id=46176>.

<sup>269</sup> Isaac Stone Simonelli et al., How One Native American Tribe is Battling for Control Over Flaring, Gaslit (Feb. 24, 2022), <https://cronkitenews.azpbs.org/howardcenter/gaslit/north-dakota.html>.

<sup>270</sup> Cushing et al., Characterizing Populations Exposed to Flaring, *supra* n.49, at 7.

<sup>271</sup> Clean Air Task Force, Tribal Communities at Risk: The Disproportionate Impacts of Oil and Gas Air Pollution on Tribal Air Quality at 6 (2018), <https://www.catf.us/resource/tribal-communities-at-risk/>.

<sup>272</sup> Audrey Carleton & Briana Flin, "Methane Is Leaking Over Native Grounds. Citizen Scientists Are Fighting Back" (July 13, 2022), <https://nexusmedianews.com/methane-is-leaking-over-native-grounds/> (citing Environmental Defense Fund, "New Report Reveals Scale of Natural Gas Waste on Navajo Nation Lands," (Mar. 21, 2019), <https://www.edf.org/media/new-report-reveals-scale-natural-gas-waste-navajo-nation-lands>); American Lung Association, "State of the Air" 2022 Report Cards: New Mexico, San Jan County, <https://www.lung.org/research/sota/city-rankings/states/new-mexico/san-juan>.

and gas companies on public and tribal lands wasted over \$500 million worth of gas in 2019, suggesting that these emissions are an issue across tribal lands.<sup>273</sup>

Commenter (2697-STA) supports the work of the EPA in engaging with and assisting tribes across the U.S. in the effort to mitigate methane and other harmful air pollutants. Tribal communities contribute the least to climate change but are disproportionately impacted by it, making this an essential component of environmental justice and holding emitters accountable.

Response II-20-69: EPA acknowledges the supportive comments.

Comment: Commenter (2245-Private Citizen) notes that, as individuals with disabilities and on limited income, the commenter and their partner, along with many of our neighbors in the Port Towns area who are seniors, do not have the resources or funds to relocate to safer and more affordable homes. They ask the EPA to consider the financial and physical impact of climate change on the people who live along the rivers and borders of the oceans.

Response II-20-70: The EPA estimates the cost of climate change impacts and benefits of avoided climate change based on the Social Cost of Greenhouse Gases (SC-GHG). The SC-GHG is a metric that puts the effects of climate change (inclusive of adaptation costs) into monetary terms to help policymakers understand the economic impacts of decisions that would increase or decrease greenhouse gas emissions. The EPA uses SC-GHG estimates to monetize the climate benefits from the GHG emissions reductions expected under the final rule within the regulatory impact analysis (RIA) conducted under Executive Order 12866.

As discussed in Section 3.2 of the Final RIA included in the docket, the SC-GHG is the monetary value of the net harm to society from emitting a metric ton of that GHG into the atmosphere in a given year. In principle, the SC-GHG is a comprehensive metric that includes the value of all future climate change impacts (both negative and positive), including changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG, therefore, also reflects the societal net benefit of reducing emissions of the GHG by a metric ton. In practice, data and modeling limitations restrain the ability of SC-GHG estimates to include all physical, ecological, and economic impacts of climate change. EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward.

Comment: Commenter (1685-Private Citizen) provides 31 pages of comments on the historical context of the presidential executive orders, and the court decisions around cumulative impacts that are required for the EPA to consider. The commenter argues, for example, that there is no implementation of EPA's framework for a Cumulative Risk Assessment in the current draft of regulations for GHGs and December 2022 Methane Supplemental considerations. In 20 years,

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<sup>273</sup> Griot, O, et al., Onshore Oil and Natural Gas Operations on Federal and Tribal Lands in the United States: Analysis of Emissions and Lost Revenue (Jan. 26, 2023), available at <https://www.edf.org/media/new-study-quantifies-natural-gas-wasted-us-public-and-tribal-lands>.

the commenter notes that EPA has not codified this into any environmental regulations. Instead, they argue that permitting continues without regard to the overburdened fence line and frontline communities suffering the health and social impacts caused by industry pollution.

Response II-20-71: EPA acknowledges the comments about cumulative risk assessment and is currently in the process of developing cumulative risk assessment methods for our quantitative environmental justice analyses. In the interim, the Oil and Gas rulemaking utilizes the “life expectancy” and “redlining” variables as a proxy to identify communities with higher or lower exposure to cumulative risks. EPA continues to improve its methodology based on its framework for a Cumulative Risk Assessment as well as guidance from multiple Executive Orders and intend to more accurately assess cumulative risk in future rulemakings.

## Chapter 21. Statutory and Executive Reviews

### 21.1 Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Comment: Commenter (2359-Competitive Enterprise Institute and Heritage Foundation) states that EPA’s proposal is not reasonable, and that an unreasonable regulation may be challenged as arbitrary and capricious. The commenter notes that EPA asserts that its climate-benefit calculations are not a factor influencing regulatory stringency. “However, we emphasize that the monetized benefits analysis is entirely distinct from the statutory [best system of emission reduction] BSER determinations proposed herein and is presented solely for the purposes of complying with [Executive Order] EO 12866”<sup>1</sup>. The commenter states that the disclaimer does not shield the proposal from litigation risk. The commenter states that EO 12866 itself serves a more basic rule of reason. The commenter notes that the Supreme Court stated in its review of the Mercury Air Toxics Standards (MATS) rule in *Michigan v. EPA*: “One would not say that it is even rational, never mind ‘appropriate’, to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits...No regulation is ‘appropriate’ if it does significantly more harm than good.”<sup>2</sup>

Response II-21-1: The EPA has responded to this comment in section VIII (Overview of Control and Control Costs) of the final rule preamble.

### 21.2 Executive Order 13132: Federalism

Comment: Commenter (2257-Michigan Oil and Gas Association (MOGA)) is concerned with the issue of Federalism and how funding will be allocated. The commenter agrees with the West Virginia Department of Environmental Protection January 14, 2022, response letter Docket ID. No. EPA-HQ-OAR-2021-0317, and questions how the EPA will appropriate funding for individual states to acquire staff, training, equipment, etc. required to monitor, collect, inspect, review, and enforce future emission guidelines (EG) proposed in EG OOOOc.

The commenter (2257-MOGA) requests that EPA be transparent regarding how funding will be appropriated and how funding is going to be allocated so that state agencies, oil and gas producers and taxpaying citizens are informed prior to consideration of proposed regulations. The commenter’s primary concern is the potential for associated costs from unfunded federal programs imposed on state agencies via “federalism” that might be passed on to oil and gas producers in each state. The commenter requests that EPA explain or provide certainties that state agencies will not solicit funding from oil and gas producers to implement unfunded federal regulations. The commenter believes that the need for these clarifications and certainties is of paramount importance since the EPA did not consider these costs when estimating their cost-

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<sup>1</sup> 87 FR 74843. BSER stands for “best system of emission reduction.” Clean Air Act section 111 performance standards are to reflect the degree of emission limitation achievable by the best system of emission reduction, taking into consideration cost, energy requirements, and non-air environmental impacts.

<sup>2</sup> *Michigan v. EPA*, 576 U.S. 743, 752 (2015), <https://supreme.justia.com/cases/federal/us/576/14-46/case.pdf>.

benefit analysis, including the financial cost feasibility analysis and justification of producer cost reduction burden per unit of methane or other emission constituents.

Commenter (2403-Petroleum Alliance of Oklahoma (PAO)) contends that there are significant Federalism issues with the December 2022 Supplemental Proposal. The commenter notes that EPA did not lessen the requirements on states as compared to the November 2021 Proposal, but stated that it updated, strengthened, and/or expanded the November 2021 Proposal for methane emissions from existing designated facilities that states would have to implement. Under its analysis of Executive Order 13132: Federalism, EPA states, “These actions will not have substantial direct effects on the states as defined in the Executive Order, on the relationship between the Federal Government and the States, or on the distribution of power and responsibilities among the various levels of government.”

However, the commenter (2403-PAO) states that Oklahoma provided comments to EPA on its November 2021 Proposal, where it states that, “[t]he most concerning issue presented by the proposed rule is the vast amount of state resources that will be required to implement the rule and the absence of any additional funding to states to account for the extreme increase in workload.” The commenter reports that Oklahoma goes on to state that the number of oil and gas permitted facilities would go from approximately 10,000 to over 200,000. The commenter asserts that there is a clear disconnect between EPA’s analysis and what states communicated to EPA.

Commenters (2219-WOGCC, 2227-Western Energy Alliance (WEA), 2237-North Dakota Industrial Commission (NDIC) and North Dakota Department of Environmental Quality (NDDEQ), 2254-Permian Basin Petroleum Association (PBPA), 2258-Marcellus Shale Coalition (MSC), 2353-CrownQuest Operating, LLC (CrownQuest)) assert that the December 2022 Supplemental Proposal has substantial direct effects on states, conflicts with state law, and fails to apply cooperative federalism principles.

Commenter (2219-WOGCC) recommends that EPA complete the required federalism evaluation appropriately. The commenter asserts that EPA requiring well plugging plans, financial assurance for well plugging, and notice of transfer of owner or operator is a significant change in the relationship between the federal government and states. The commenter notes that states consider a variety of criteria when determining appropriate well plugging plans and financial assurance. The commenter questions what happens in the future when a state requires certain procedures in a plugging plan that EPA would not approve. The commenter questions whether EPA will overrule a state on a process EPA does not even have authority over. The commenter believes this is a clear change in the distribution of power and responsibilities and the relationship between the federal government and the states.

Commenter (2258-MSC) asserts that states are neither subjects of nor created by the federal government. While federal laws duly enacted by the U.S. Congress are applicable to the states, the state has historically been the primary regulator of the activities within its borders. With respect to oil and gas activity and its regulation, intended to protect both the environment and public health, the commenter states that Pennsylvania has a mature regulatory regimen that adequately addresses most if not all the criteria that EPA seeks to promulgate. The commenter

asserts that in some areas, such as well closure plans, the Agency clearly seeks to expand its historic role of oil and gas oversight under the guise of air quality. The commenter states that this extension is tenuous at best and not justified by any demonstration that the various states are not already adequately addressing the underlying issue or equipped with the necessary statutory authority to do so if warranted.

The commenter (2258-MS) believes that, in abandoning the long-held and successful principle of cooperative federalism, the Agency seeks to impose a one-size-fits-all regulatory framework upon the states themselves, negating the states' authority to design different but equally effective regulatory programs. According to the commenter, the EPA imposes unnecessary, burdensome, and duplicative requirements upon not only industry, but the states themselves. It creates significant uncertainty and perpetuates confusion upon the industry as to what standards it is to meet; applicable to what date; and achieved within what timeframe. In doing so, the commenter believes that EPA wastes valuable and limited government resources, while also significantly raising the overall cost of doing business for operators with little, if any, commensurate environmental benefit for their citizens.

Commenter (2227-WEA) believes that the proposed rules reflect a broad-brush, one-size-fits all approach and do not account for significant regional challenges and differentiators that occur in distinctive parts of the U.S., particularly in the Rocky Mountain West with its wide-open and topographically difficult expanses and extreme weather conditions. In addition, contrary to EPA's assertion in the *Federal Register* notice, the commenter states that federalism implications from the proposed rules do exist and they will substantially and directly affect states and their relationship with the federal government. A prime example of this, according to the commenter, is designation of an oil well with associated gas as an affected facility, which is duplicative and conflicts with the existing regulation of flaring by various state oil and gas commissions.

Commenter (2237-NDIC/NDDEQ) states that the December 2022 Supplemental Proposal substantially intrudes on North Dakota's authority to implement and enforce its own methane emissions control program. The commenter asserts that the nearly four decades of Clean Air Act (CAA) reporting by the commenter clearly demonstrate the responsible operation and consistent success of North Dakota's programs.

Commenter (3845-ND Congress) asserts that EPA's proposed rule conflicts with core principles of federalism and states' rights by undermining state regulatory programs implemented by the North Dakota Industrial Commission ("NDIC") and North Dakota Department of Environmental Quality ("NDDEQ"). The commenter reports that the NDIC has already reduced flaring significantly via implementation and enforcement of gas capture goals. As of April 2023, statewide gas capture in North Dakota was 95 percent. The NDIC also has a robust program covering plugging and abandonment of oil and gas wells. The commenter notes that the EPA's proposed additional restrictions on flaring and well closure requirements fly in the face of the NDIC's efforts and authority. The commenter provides that the NDDEQ investigates and enforces violations of North Dakota's air regulations, including enforcement of federal regulations delegated to North Dakota under the CAA. The commenter adds that the NDDEQ has effectively implemented this delegated authority for decades. Yet, the commenter asserts that the EPA's proposed super-emitter response program would deputize third parties to encroach on

NDDEQ's delegated authority. The commenter believes that responding to third parties, likely with limited experience, will undermine NDDEQ's existing investigative process and create unnecessary churn for the agency. To add to this issue, the commenter states that the EPA has released no guidance on how it expects states to implement the super-emitter response program, raising additional concerns with the scope and degree of NDDEQ's oversight in this process. Commenter (2254-PBPA) states that the proposed NSPS OOOOb conflicts with and overrides states' oil and gas regulations. With respect to oil wells with associated gas, the commenter notes that EPA's position on flaring overlaps with existing state regulations that already prohibit or limit flaring under appropriate circumstances, that are enforced by agencies with relatively more on-the-ground knowledge than EPA, and that reflect states' interests in conserving their own resources.<sup>3</sup> Further, the commenter states that EPA's proposed well closure plan overlaps with existing state regulations that already address well closure and financial assurance.<sup>4</sup>

The commenter (2254-PBPA) provides that EPA admitted in its November 2021 Proposal that "[t]he proposed EG OOOOc may have federalism implications because development of State plans may entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with State legislatures as appropriate, and develop a plan submittal."<sup>5</sup> The commenter states that EPA has not explained its new (opposite) view in the December 2022 Supplemental Proposal.

In addition, out of respect for cooperative federalism and each state's on-the-ground expertise, the commenter (2254-PBPA) requests that EPA allow states to adopt existing source performance standards (ESPS) that take a different form of numerical standards than the "presumptive" numerical standards that EPA has proposed as long as States can demonstrate equivalency.<sup>6</sup> The commenter notes that CAA 111(d) only requires EPA to "establish a procedure" under which each state can submit ESPS plans,<sup>7</sup> as opposed to requiring EPA to establish "presumptive" numerical standards. The commenter believes it is misguided to predetermine that states cannot demonstrate equivalency, whether on a source category or programmatic level, because an overly prescriptive approach would eliminate flexibility needed to make adjustments to accommodate advancements in technology and operational practices.

Commenter (2353-CrownQuest) asserts that the December 2022 Supplemental Proposal conflicts with state law and fails to apply cooperative federalism principles. The commenter believes that the rules are a broad one-size-fits all approach, and do not allow for state variances. The commenter states that EPA insists on treating all minor oil and gas emission sites as major emitting sites. The proposed rule justifies an emissions reduction based on the total onshore oil and gas production category rather than the intended source segment per the CAA.

An example of this misguided approach, the commenter (2353-CrownQuest) notes that EPA reclassifying multiple wellhead production sites as "facilities" because they are not remote like single wellheads are. The commenter reports that operators monitor a multi-wellhead site for the

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<sup>3</sup> See, e.g., 16 Tex. Admin. Code §3.32 (Railroad Commission of Texas gas release requirements).

<sup>4</sup> See, e.g., 16 Tex. Admin. Code §3.14 (Railroad Commission of Texas plugging requirements).

<sup>5</sup> 86 Fed. Reg. 63,110, 63,261 (Nov. 15, 2021).

<sup>6</sup> 87 Fed. Reg. at 74,706 (referring to presumptive standards in EG OOOOc).

<sup>7</sup> 42 U.S.C. §7411(d)(1).

same time as a single-wellhead site. The commenter notes that EPA swapped the term “remote,” which described the location and disconnection of these sites, with “centralized.” This change indicates that multi-wellhead sites are now a facility rather than the discrete, remote, and low-emission sites they are. The commenter notes that nothing changes with wellheads if there are one or multiple on a site – they remain remote and seldom visited. The commenter asserts that it is a misinterpretation to conflate that these are now “sites” by adding a few extra pieces. The commenter contends that EPA cherry-picks studies to show leak rates in addition to their estimation of over half a million new sites to EPA regulation. The commenter highlights in their comment letter that the modeling approach that EPA takes makes no sense other than to apply a one size fits all approach to make it easier for the EPA to track.

The commenter (2353-CrownQuest) notes that EPA developed these rules over a multiyear period and has produced over 2,000 pages for the proposed rule. The commenter contends that the rule text, with 180 pages of proposed regulation, is not concise nor an exact technical specification for industries to follow. Instead, the commenter believes that the rule is mainly broad generalities. The commenter notes an example is the annual report for each regulated item that explains how the operator complied with these broad rules. Instead of what they believe are burdensome, expensive, and convoluted rules, they assert that EPA should embrace the changes the industry already has made in collaborative BSER. The commenter adds that the EPA’s overview references a 2005 level, which the commenter believes shows their bias for their predetermined plan instead of the tremendous work and methods the oil and gas industry has undertaken to reduce methane emissions from 1990 to 2020.

Another example highlighted by the commenter (2353-CrownQuest) is the requirement that states implement EG OOOOc standards within 18 months. The commenter states that EPA spent over two years developing, according to them, a restrictive yet unspecific rule and passed on the hard regional work and analysis. The commenter believes it is dishonest to overtly state a rule this restrictive that specifically keeps states from varying from the proposed rule.

Response II-21-2: To the issue of EPA appropriating funding for individual states to fulfill the state’s duty to implement subpart OOOOc EG, the EPA does not appropriate funding as the commenter suggests. The U.S. Congress authorizes and appropriates funds to EPA that are disbursed through EPA to the various states in support of their authorized and delegated duties of environmental protection. The amount of funding is not set or determined by EPA. Funds given to states by Congress through EPA are provided based on many factors including anticipated needs on the part of states to fulfill their role in protecting the environment in many capacities such as those cited by the commenter. In sum, EPA provides all the eligible funds it can as authorized and appropriated by Congress for that purpose.

One commenter requested that EPA explain or provide certainties that state agencies will not solicit funding from oil and gas producers to implement unfunded federal regulations. The EPA can offer no such assurance or certainty. States operate environmental protection programs under state authorities that do include the power of taxation, user fees, and other means of generating revenue for the purpose of operating state programs, including those programs that protect the environment. While the U.S. Congress does authorize and appropriate funding through EPA for state environmental programs, states are expected to provide their own funding for the protection



of the environment from the constituents they serve. Those funds are in turn authorized for collection by the legislative and executive authorities in those states. EPA has absolutely no ability to influence those deliberations beyond the normal channels of communication between EPA and the state environmental protection agencies in our shared mission to protect the environment and human health.

EPA cannot comment on the accuracy of the estimate of the commenter that the state will be required to issue permits for an additional 190,000 affected facilities without additional information in support of such an assertion. In response the EPA points out that the NSPS OOOOc EG does not require that states issue facility-specific permits to affected facilities under OOOOc EG. Many states employ different administrative means such as general permits, permits by rule, and approved SIPs to regulate affected facilities under the NSPS. The state is expected to submit plans under section 111(d) to designate facilities subject to OOOOc EG with the intent to ensure compliance with the EPA EG or equivalent standards developed by the state. As stated in response to other commenters' concerns about adequate funding, the EPA provides all the funds authorized and appropriated from the U.S. Congress for that purpose to the state agencies, to be combined with the funds appropriated and authorized by their state governments, to protect human health and the environment.

The EPA disagrees with the premise of the comment asking "what happens in the future when a state requires certain procedures in a plugging plan that EPA would not approve." The commenter continues by asking whether EPA "will overrule a state on a process EPA does not even have authority over." The EPA has independent authority to enforce subparts OOOOb under the Act. If a state fails to act under 111(d) such that EPA ultimately promulgates a federal plan implementing OOOOc EG, EPA would then have authority under the Act to implement and enforce the provisions for wells that permanently shut down that require capping or plugging under OOOOc. In the alternative, states may submit their 111(d) plans for approval by EPA. EPA would approve plans under 111(d) that meet the minimum requirements of OOOOc EG. In the scenario provided by the commenter that EPA and a state could disagree about whether a provision of a state 111(d) plan meets those minimum requirements, EPA and the state agency would engage in rule and comment rulemaking to arrive at a conclusion subject to administrative and judicial review. There is nothing new, novel, or different about such a process than that envisioned by the Congress as expressed in the Act.

Contrary to the assertion of the commenter "that in some areas, such as well closure plans, the Agency clearly seeks to expand its historic role of oil and gas oversight under the guise of air quality," the EPA is within its authority to add affected sources to a standard where the emissions profile of such sources indicate regulation is appropriate. Abandoned wells leaking VOC, HAP, and methane are a well-documented source of emissions across the United States, notwithstanding the success of some states to address the issue. EPA is within its authority under the Act and section 111 to add to the list of affected regulated facilities those emission points that emit the same pollutants as other affected facility emission points, in this case leaking abandoned wells.

Contrary to the assertion of the commenter that EPA is "...in abandoning the long-held and successful principle of cooperative federalism..." the EPA believes that section 111(d) is the

embodiment of cooperative federalism envisioned by Congress. The EPA has fulfilled its duty to provide federal guidelines in the form of duly promulgated subpart OOOOc EG under the Act's section 111(d) as Amended in 1990, which in turn calls the state to create and adopt a single or series of state standards subject to review, approval and consent of the state government that create the equivalent level of protection for their constituents, improving protection for the environment and human health. The NSPS has fulfilled this role dating back to the original Clean Air Act of 1970<sup>8</sup> and its subsequent reauthorizations over the following 53 years.

One commenter referenced the EPA addition of associated gas as a regulated emission point. Like the example of abandoned leaking wells, section 111(b) provides the authority for EPA to regulate additional points of emissions of regulated pollutants where the Administrator determines it may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare. Emissions of associated gas are not substantively different than any other emission point regulated by the NSPS affected facilities regulated thus far under OOOO or OOOOa. While the various states may have standards applicable to these sources, that does not mean that all states have done so, or that all states have done so effectively. The foundation of the Act and sections 111(b) and (d) are to assure all states and their citizens the level of protection for human health and the environment to which they are entitled by law.

Response II-21-3: As explained in section X.C and XI.C of the final rule preamble, EPA has finalized the Super Emitter Program as primarily a compliance assurance program with EPA in a centralized role to certify third-parties, receiving and reviewing data from these third, and then notifying owner or operators if the data received from the third party is accurate and reasonable, The final rule no longer permits third party's from notifying owner or operators directly.

EPA disagrees with the commenter asserting that the EPA's proposed super-emitter response program would deputize third parties to encroach on NDDEQ's delegated authority. See the response to comment II-14-4 where EPA explains the limited obligations that the super-emitter initiative places on operators, which does not include responding to reports from deputized third parties. See response to comment II-14-5 on the role that EPA has assigned itself for implementing the program so that "unnecessary churn" is unlikely. The Super Emitter Program is being finalized primarily as a compliance assurance program and is not an enforcement program. In response to the comment that EPA has released no guidance on how it expects states to implement the super-emitter response program, raising additional concerns with the scope and degree of NDDEQ's oversight in this process, EPA is developing a centralized reporting portal to handle receive super emitter reports. The final rule, as described in Section X.C.4 of the preamble has universal reporting requirements which all affected owner or operators who receive a notification must submit. While this information will be submitted to the EPA, the system will be designed to make the data available to all stakeholders, including the state, local, and tribal authority.

See Chapter 6 in response to EPA standards regulating associated gas. As explained in Response II-6-52 and II-6-54, EPA reviewed state standards to arrive at the final promulgated standards for

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<sup>8</sup> PUBLIC LAW 91-604-DEC. 31, 1970.

associated gas and has established similar provisions for allowing flaring under exigent circumstances and certain recurring events that require flaring.

With respect to the comment on the implications for federalism in the NSPS and section 111(d), EPA directs the commenter's attention to the discussion explaining our change of viewpoint beginning at 87 FR 74812.

EPA agrees that the process provided for under section 111(d) with respect to state plans to implement OOOOc does allow for flexibility to address sources with state standards equivalent to the presumptive standards in OOOOc EG. In addition, under certain circumstances and with adequate demonstration that it is appropriate, a state can prescribe a standard to a subcategory of sources that are subject to a less stringent standard when considering its remaining useful life.

The EPA disagrees that the NSPS treats all minor oil and gas emission sites as major emitting sites. The NSPS applies to affected facilities regardless of whether they are located at major sources for criteria or HAP emissions. Subpart OOOOb and OOOOc EG are based on the same authority of the Act as Amended in 1990 and does not in any way violate state law.

EPA disagrees with the comment with respect to the difference between a well site with one well and associated equipment, and a well site with multiple wells on a single well pad also with associated equipment. As explained in the supplemental proposal, EPA analysis for leaking and fugitive emission monitoring is based on the data from leak and fugitive emissions from affected facility components. As the commenter knows, more well heads require more components and bring with them the greater probability of leaks and fugitive emissions. EPA has attempted to balance the need for periodic monitoring with the data underlying the probabilities of leaks and fugitive emissions, rather than prescribe a single high frequency of monitoring that ignores the variation in well sites, the very policy that the commenter asserts that EPA is pursuing. The remote or central location of a well site is not indicative of the equipment counts found on well pads, and therefore not predictive of leak and fugitive emission rates.

The EPA is embracing the changes the industry has made in most of this final rule with respect to advancing technology for methane abatement. For example, the EPA fugitive inspection program using OGI and the super-emitter program have been developing with the emerging technology since the promulgation of subpart OOOOa in 2016 (81 FR 35824). EPA published a specific request for information to gather additional data on emerging technology (81 FR 46670) for methane abatement. Technologies for which we received data or information are now entering the market and may be used to meet the requirements of subparts OOOOb and OOOOc EG.<sup>9</sup>

EPA responds to the comment that EPA has passed on the "hard regional work..." to the states for execution under OOOOc EG by reiterating our duty and authority to implement the NSPS under section 111 of the Act as Amended, which creates the framework for cooperative federalism in protecting human health and the environment.

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<sup>9</sup> See EPA Docket ID EPA-HQ-OAR-2016-0346.

## **21.3 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments**

Comment: Several commenters (2163-EOS, 2177-Southern Ute Indian Tribe (Southern Ute), 2181-Ute Indian Tribe of the Uintah and Ouray Reservation (Ute Indian Tribe), 2303-National Tribal Air Association (NTAA), 2331-Mandan, Hidatsa and Arikara (MHA) Nation) request that EPA expand Tribal consultation and coordination. The commenters present policies and standards that EPA must follow to ensure Tribal sovereignty and self-determination. Examples of some of the specific comments provided are included in the following paragraphs.

Commenter (2163-EOS) asserts the proposed rule should be principles based and ensure that Tribal Nations have a voice in the development of resources within their territories.

Commenter (2303-NTAA) urges EPA to consult directly with Tribes on a government-to-government basis and asserts that the EPA must evaluate the industry's and proposed rule's unique impact to Tribes. The commenter states that public listening sessions and training webinars are helpful but not sufficient.

The commenter (2303-NTAA) agrees with EPA's recognition that national standards and guidelines are needed to reduce methane and other harmful pollutants from new and existing sources in the oil and natural gas industry. The commenter states that significant oil and natural gas sources are on and near Tribal lands, and methane, volatile organic compound (VOC), and hazardous air pollutant (HAP) emissions from the oil and natural gas industry negatively impact Tribal communities. The commenter asserts that each Tribe's unique circumstances must be evaluated. Additionally, oil and natural gas development can provide important revenue for Tribes, making strong, cost-effective national requirements and standards even more important.

The commenter (2303-NTAA) states environmental justice concerns may apply to many American Indian/Alaska Native communities, and the commenter urges EPA to properly address environmental justice concerns. That concern for environmental justice, however, cannot replace government-to-government consultation with Tribes. The commenter states that Tribes are sovereign nations with self-determination and cannot be treated the same as environmental justice communities. The commenter asserts that EPA must consult directly with Tribes on a government-to-government basis and must evaluate the industry's and proposed rule's impacts to Tribes.

The commenter (2303-NTAA) notes that on January 26, 2021, President Biden issued a Memorandum on Tribal Consultation and Strengthening Nation-to-Nation Relationships committing to honoring Tribal sovereignty and including Tribal voices in policy deliberation that affects Tribal communities. The commenter urges EPA to take this commitment seriously in finalizing and implementing regulations for the oil and natural gas industry.

Commenters (2177-Southern Ute, 2181-Ute Indian Tribe) request that EPA defer to the standards set in the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and employ the concept of Free, Prior, and Informed Consent (FPIC). The commenters note that the UNDRIP sets the bare minimum standards of tribal consultation, including treaty

acknowledgement and tribal sovereignty, and FPIC is vital for the engagement of meaningful consultation. The commenters add that these two standards require tribal approval for all rules implemented on their lands and tribal oversight on any program proposed.

The commenters (2177-Southern Ute, 2181-Ute Indian Tribe) request consultation and approval prior to any rule that will directly affect their lands. If the rule is finalized prior to tribal approval, the commenters request tribal exemptions to any section of the proposed rule that affects tribal nations, and deferral to tribal implementation plans and tribal authority.

The commenters (2177-Southern Ute, 2181-Ute Indian Tribe) note that the proposed rule states that “[t]he EPA notes that this supplemental proposal does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes.” However, the commenters assert that operators on tribal lands will be affected by these proposed standards and state that there are no tribal exemptions.

Commenter (2331-MHA Nation) asserts that the December 2022 Supplemental Proposal must reflect EPA’s Federal Trust Obligations and Acknowledge Tribal treaty rights and include direct engagement with Tribes. As the commenter notes that they provided in their previous comments, in promulgating regulations aimed at protecting human health and the environment that apply to oil and gas development on tribal lands, EPA must still consider its trust responsibility to individual tribes and whether its regulations will have implications for specific tribal treaty rights.<sup>10</sup> The commenter adds that EPA has expressly “recognize[d] the right of tribes as sovereign governments to self-determination and acknowledge[d] the federal government’s trust responsibility to tribes.”<sup>11</sup> The commenter states that this responsibility requires engaging with tribes on an individual basis to understand how a forthcoming rulemaking will implicate development of tribal trust resources and rights protected by treaties. As the EPA looks to finalize and implement the supplemental proposal, the commenter encourages EPA to continue to engage with tribes on a government-to-government basis to uphold its trust responsibility and ensure its final regulations do not infringe on tribal treaty rights.

Commenter (2331-MHA Nation) requests that EPA work with Tribes to support and facilitate achieving Treatment as a State (TAS). As noted previously, the commenter asserts that the TAS process is burdensome and does not facilitate development of tribally led and administered CAA programs.<sup>12</sup> As a result, the commenter states that the TAS process is underutilized and tribes continue to rely on federal plans despite expressing interest in developing their own tribal clean air requirements.<sup>13</sup> The commenter has expressed to EPA its interest in pursuing TAS to develop its own standards for the oil and gas industry. However, it is unlikely the commenter will have developed the resources and expertise required to achieve TAS to submit its own EG in

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<sup>10</sup> See Comment submitted by Mandan, Hidatsa and Arikara (MHA) Nation, at 1-2, Docket ID No. EPA-HQ-OAR-2021-0317-0794.

<sup>11</sup> See *id.* at 2; see also U.S. Environmental Protection Agency, Memorandum from EPA Administrator Michael S. Regan, to all EPA Employees, regarding “Reaffirmation of the U.S. Environmental Protection Agency’s Indian Policy”, at 1 (Sept. 30, 2021), Scanned Document (epa.gov).

<sup>12</sup> Comment submitted by Mandan, Hidatsa and Arikara (MHA) Nation, at 3-4, Docket ID No. EPA-HQ-OAR-2021-0317-0794.

<sup>13</sup> *Id.*

compliance with the timeline proposed under the December 2022 Supplemental Proposal. The commenter expresses that, like many other tribes, it will be forced to rely on a federal plan until TAS requirements are met.

In addition to presenting tribes with the option of submitting EG, the commenter (2331-MHA Nation) requests that EPA actively work with tribes to provide access to the funding and technical assistance required for tribes to apply for TAS to develop these plans, including working with tribes to develop technical expertise and acquire equipment necessary to monitor and gather data on oil and gas emissions sources in Indian country. The commenter understands that the Inflation Reduction Act (IRA) allocated funds to EPA to provide grants and support to tribes and states with monitoring and reducing air emissions (including methane emissions from the oil and gas sector), CAA research and development, and climate pollution reduction, among other programs and initiatives.<sup>14</sup> To the extent these funds and other EPA programs could support tribes in developing the knowledge and expertise required to successfully apply for TAS to implement EG under this proposal, the commenter encourages EPA staff to work with tribes to provide technical assistance and identify those funding sources early on in the grant application process so that tribes can take advantage of those opportunities and move toward establishing their own clean air programs. The commenter believes that providing the option to develop EG without connecting tribes to the resources and support required to do so does little to support tribes in exercising their sovereignty to develop clean air regulations aimed at protecting health and welfare in Indian country.

Response II-21-4: As discussed in section XVII.F (Executive Order 13175: Consultation and Coordination with Indian Tribal Governments) of the final rule preamble, Tribal consultations were completed after the November 2021 Proposal at the request of the Northern Arapahoe Tribe, MHA Nation, and Eastern Shoshone Tribe.<sup>15</sup> Additional tribal consultation was completed at the request of MHA Nation and an informational meeting was held with the Ute Tribe after the December 2022 Supplemental Proposal.<sup>16</sup> Consistent with previous actions affecting the Crude Oil and Natural Gas source category, the EPA understands there is continued significant tribal interest because of the growth of the oil and natural gas production in Indian country. In accordance with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will continue to engage in consultation with tribal officials as these rules become implemented.

As stated in the November 2021 Proposal, the EPA found that 112 unique tribal lands are located within 50 miles of an affected oil and natural gas source, and 32 tribes have one or more oil or natural gas sources on their lands. The while many of the affected and designated facilities impacted by final NSPS and EG on tribal lands are owned by private entities, some tribes also own affected and or designated facilities. There would be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or in the case of the NSPS, a tribal government is given delegated authority to enforce the rulemaking. Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing

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<sup>14</sup> The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investment in Clean Energy and Climate Action (Jan. 2023) <https://www.whitehouse.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf>.

<sup>15</sup> See Memorandum in EPA-HQ-OAR-2021-0317.

<sup>16</sup> See Memorandum in EPA-HQ-OAR-2021-0317.

sources. The EPA notes that this final rule does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes.

See also, Volume I, Chapter 6 (Environmental Justice (EJ) Implications and Stakeholder Outreach), subsection 6.1.2 (Native American Environmental Justice Impacts ), Responses I-6-2 through I-6-4, for EPA's response to comments on EPA's EJ analyses.

Comment: Commenter (2241-Utah Department of Natural Resources (UDNR)) provides details of successful voluntary efforts to show that using incentives and allowing industry and state and tribal governments self-regulation is the most successful approach.

The commenter (2241-UDNR) mentions the Western States and Tribal Nations Natural Gas Initiative (WSTN) voluntary initiative. The WSTN was established in 2021 through a memorandum of understanding signed by state and tribal governments including the Utah Office of Energy Development, the Wyoming Energy Authority, the Ute Indian Tribe of the Uintah and Ouray Reservation, the Secretariat of Economic Development of Baja California Mexico, the Colorado counties of Garfield, Mesa, Moffat, and Rio Blanco, and the New Mexico Energy, Minerals, and Natural Resources Department, and the Jicarilla Apache Nation.<sup>17</sup> The commenter notes that the WSTN is taking a proactive approach to addressing Rural Economic Development, Tribal Self Determination, Climate Change, carbon Net Zero.<sup>18</sup>

In December 2022, the commenter (2241-UDNR) reports that the WSTN held its West Coast Liquefied Natural Gas Export Forum at Colorado Mesa University in Grand Junction, Colorado.<sup>19</sup> During this forum, various natural gas related topics were raised and discussed including the fact that Rocky Mountain natural producers are leading the way in decarbonizing natural gas production,<sup>20</sup> partly through the WSTN's efforts. The commenter notes that more importantly, the forum discussed tribal perspectives on energy production on tribal lands, with top leaders representing the Navajo Nation, the Crow Tribe of Indians and their member nations the Ute Indian Tribe, the Southern Ute Indian Tribe and the Jicarilla Apache Nation.<sup>21</sup> The commenter notes that, according to the forum report, "all five tribes have energy development interests and shared their concern that the use of their sovereign land is hampered by the 'paternal approach,' as one panelist put it, taken by the federal government bureaucracy. Panelists questioned the commitment to genuine tribal consultation, and urged immediate reform to layers of red tape that means tribes must follow Bureau of Indian Affairs and Environmental Protection Agency rules even to build roads on their reservation, let alone develop energy

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<sup>17</sup> WSTN, Second Revised Memorandum of Understanding Establishing the Western States and Tribal Nations Natural Gas Initiative, Western States and Tribal Nations Natural Gas Initiative, available at: <https://westernnaturalgas.org/wp-content/uploads/WSTN-MOUR-August-3-2021.pdf> (2021); see also <https://westernnaturalgas.org/governments-members/>.

<sup>18</sup> WSTN, Our Guiding Principles, Western States and Tribal Nations Natural Gas Initiative, available at: <https://westernnaturalgas.org/our-guiding-principles/> (2022).

<sup>19</sup> WSTN, WSTN President's Message: West Coast LNG Export Forum Wrap up, Western States and Tribal Nations Natural Gas Initiative, available at: <https://westernnaturalgas.org/2022/12/21/wstn-presidents-message-west-coast-lng-export-forum-wrapup/> (2022).

<sup>20</sup> Id.

<sup>21</sup> Id.

resources.”<sup>22</sup> The commenter believes that this paternal approach identified by these tribal leaders echoes the state’s sentiment that the current proposed rule will simply add on more government oversight, regulatory burden, and other increased “paternalistic” factors where they are not needed.

Response II-21-5: EPA responds to the comment by reiterating our duty and authority to implement the NSPS under section 111 of the Act as Amended, which creates the framework for cooperative federalism in protecting human health and the environment. We also direct the commenter to EPA’s discussion of federalism and it relates to this NSPS at 87 FR 74812.

See also Responses II-21-2 and II-21-3 of this Chapter.

Comment: Commenter (2392-Earthjustice *et al.*) states that Tribal communities are specifically vulnerable to climate-driven impacts on cultural practices and access to traditional lands. The commenter reports that both the United Nations Educational, Scientific, and Cultural Organization (UNESCO) and the Intergovernmental Panel on Climate Change (IPCC) recognize that “climate change represents one of the greatest threats to culture and heritage.”<sup>23</sup> This is particularly true for tribal communities, as “the consequences of observed and projected climate change have and will undermine indigenous ways of life that have persisted for thousands of years.”<sup>24</sup> The commenter notes that while some indigenous resource managers “believe their cultures already possess sufficient knowledge to respond to climate variation and change,” the loss of traditional knowledge may undercut tribal community resilience to climate change.<sup>25</sup>

Although a great diversity exists amongst tribal communities and cultural practices across the U.S., the commenter (2392-Earthjustice *et al.*) asserts that many indigenous cultures entail a unique connection to, and relationship with, the natural environment. Research demonstrates that impacts of climate change, including increased frequency of wildfires, higher temperatures, and extreme changes to local ecosystems “will affect the quantity and quality of the resources tribes depend upon to perpetuate their cultures and livelihoods.”<sup>26</sup> For example, the Yurok Tribe in northern California culturally identify as “great fisherman” and rely upon ney-puy, the Yurok word for salmon, harvested from the Klamath River for food.<sup>27</sup> In recent years climate-driven hot weather and drought conditions have warmed the river’s water giving rise to parasites that have

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<sup>22</sup> Id.

<sup>23</sup> Press Release, UNESCO World Heritage Convention, UNESCO-IPCC-ICOMOS Meeting Strengthens Synergies Between Culture and Science for Climate Action (Feb. 3, 2023), <https://whc.unesco.org/en/news/2390#:~:text=Climate%20change%20represents%20one%20of,solutions%20to%20these%20mounting%20challenges>.

<sup>24</sup> T.M. Bull Bennett et al., Indigenous Peoples, Land, and Resources, in Climate Change Impacts in the United States: The Third National Climate Assessment at 298 (2014), [https://nca2014.globalchange.gov/downloads/low/NCA3\\_Full\\_Report\\_12\\_Indigenous\\_Peoples\\_LowRes.pdf](https://nca2014.globalchange.gov/downloads/low/NCA3_Full_Report_12_Indigenous_Peoples_LowRes.pdf).

<sup>25</sup> Id. at 301.

<sup>26</sup> Garrit Voggesser et al., Cultural Impacts to Tribes from Climate Change Influences on Forests, 120 Climate Change 615, 615 (2013), [https://www.fs.usda.gov/pnw/pubs/journals/pnw\\_2014\\_voggesser.pdf](https://www.fs.usda.gov/pnw/pubs/journals/pnw_2014_voggesser.pdf).

<sup>27</sup> The Yurok Tribe, Our History (last visited Feb. 3, 2023), <https://www.yuroktribe.org/our-history>.



depleted salmon stocks to dangerously low levels.<sup>28</sup>

Moreover, the commenter (2392-Earthjustice *et al.*) states that climate change now threatens to accelerate indigenous displacement. Indigenous communities in the U.S. have already been dispossessed of nearly 99 percent of their historical land base.<sup>29</sup> Centuries of colonialism in the U.S. forced many tribes off their ancestral homelands and onto reservations, such as with the MHA Nation and the Garrison Dam project (discussed above). These land losses will only continue as climate change progresses. The commenter reports that in Alaska, at least 31 native communities “face imminent climate displacement from flooding and erosion.”<sup>30</sup> The village of Newtok initiated complete relocation in 2019 due to shoreline erosion from thawing permafrost and storm surge.<sup>31</sup> Likewise in Louisiana, the commenter reports that land subsidence worsened by climate-accelerated sea-level rise forced the Biloxi-Chitimacha-Choctaw to abandon their coastline territories.<sup>32</sup>

Response II-21-6: We interpret the comment as support for our proposal and supplemental proposal; as such, no response is required.

## **21.4 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations**

Comment: Commenters (2163-EOS, 2257-MOGA, 2355-Constellation Energy Corporation (CEC), 2392-Earthjustice *et al.*) request robust engagement with vulnerable communities, and clearly defined engagement requirements.

Commenter (2392-Earthjustice *et al.*) recognizes that EPA’s obligation to identify and address environmental justice concerns is rooted in Executive Orders, implementing agency guidance, and public pronouncements of the Biden Administration. Collectively, the commenter states that these legal and policy documents articulate a two-fold obligation.

The commenter (2392-Earthjustice *et al.*) asserts that first, EPA must analyze the substantive impacts of proposed regulations on disproportionately impacted communities. Second, EPA must guarantee procedural justice by ensuring that disadvantaged communities have access to

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<sup>28</sup> Audrey Carleton & Briana Flin, In the Pacific Northwest, Salmon Declines Upend a Way of Life, *The Nation* (Aug. 30, 2022), <https://www.thenation.com/article/society/salmon-oregon-yurok>; R. Adam Ray et al., Relationship Between Temperature and *Ceratomyxa shasta*–Induced Mortality in Klamath River Salmonids, 98 *J. Parasitology* 520, 520-26 (2012), [https://www.waterboards.ca.gov/waterrights/water\\_issues/programs/hearings/marblemountain/exhibits/nat\\_marine\\_fs\\_exhibits/nmfs\\_37.pdf](https://www.waterboards.ca.gov/waterrights/water_issues/programs/hearings/marblemountain/exhibits/nat_marine_fs_exhibits/nmfs_37.pdf).

<sup>29</sup> Justin Farrell et al., Effects of Land Dispossession and Forced Migration on Indigenous Peoples in North America, 374 *Sci.* 578, 580 (2021), <https://www.science.org/doi/10.1126/science.abe4943>.

<sup>30</sup> Dalia Faheid, Indigenous Tribes Facing Displacement in Alaska and Louisiana Say the U.S. Is Ignoring Climate Threats, *Inside Climate News* (Sept. 13, 2021), <https://insideclimatenews.org/news/13092021/indigenous-tribes-alaska-louisiana>.

<sup>31</sup> *Id.*

<sup>32</sup> Dalia Faheid & Katie Livingstone, To Flee, or to Stay Until the End and Be Swallowed by the Sea, *Inside Climate News* (July 18, 2021), <https://insideclimatenews.org/news/18072021/to-flee-or-to-stay-until-the-end-and-be-swallowed-by-the-sea>.

decision-making processes and that community feedback can and does influence the agency's final decisions.

Commenter (2163-EOS) argues the proposed rule should be principles-based and needs to require timely and equitable engagement for stakeholders and communities most affected by and/or vulnerable to impacts. They add that rules need to address and improve public health and safety and environmental justice. The commenter adds that methane emissions reduction is important from an environmental justice perspective. The commenter notes that poor and marginalized (including indigenous) communities are expected to incur disproportionately high negative impacts of climate change and that they are least equipped to absorb those impacts. They contend that this could exacerbate existing inequities and add another layer of investment risk. They add that methane leaks and flaring can be accompanied by toxic and particulate matter with deleterious local health impacts.

Commenter (2355-CEC) urges EPA to include strong environmental justice measures in the final rule to protect disadvantages and overburdened communities. The commenter encourages EPA to finalize the new provisions requiring states to include certification and evidence of meaningful engagement in their state plans. The commenter agrees that a state be required to provide a list of pertinent stakeholders, summary of engagement and stakeholder input in their plan submittal. The commenter agrees that EPA must evaluate states' demonstrations regarding meaningful engagement and that a lack of these elements are grounds for EPA to find the submission incomplete or to disapprove the plan. Finally, the commenter agrees with EPA's proposed definitions of "meaningful engagement" and "pertinent stakeholder."

Commenter (2257-MOGA) implores EPA to outline its explicit intention, direction and limitations when encouraging community engagement related to oil and gas production related facilities. The commenters primary concern is safety. Michigan's oil and gas industry employees are arguably the most highly skilled, trained, insured and safety-oriented workforce in the United States. The commenter urges EPA to clearly define its proposed "community engagement" intent and provide specific restrictions and associated guidelines to prevent injuries.

Response II-21-7: The EPA, in the development of the final NSPS OOOOb and EG OOOOc rules, engaged with communities most affected by, and vulnerable to, adverse climate and air quality impacts from oil and gas operations. The EPA also conducted an EJ assessment for this action. The documentation for this assessment is contained in section 4 of the *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for the November 2021 Proposal,<sup>33</sup> in section 4 of the *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for the December 2022 Supplemental Proposal,<sup>34</sup> and in section 4 of the *Regulatory Impact Analysis for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for this action. See section XVII.J (Executive

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<sup>33</sup> See Document ID No. EPA-HQ-OAR-2021-0317-0173.

<sup>34</sup> See Document ID No. EPA-HQ-OAR-2021-0317-1566.

Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing our Nation's Commitment to Environmental Justice for All) of the final rule preamble for a summary of EPA's environmental justice assessment conducted in support of this final rulemaking.

Please also see section VII (Summary of Engagement with Pertinent Stakeholders) of the final rule preamble for a summary of engagement with pertinent stakeholders, including, but not limited to, industry, small businesses, tribal nations, and communities most affected by, and vulnerable to, the impacts of the rule. For example, the EPA hosted a two-part webinar training specifically targeted toward both communities with EJ concerns and tribal nations on November 16 and 17, 2021. The purpose of this training event was for the EPA to facilitate stakeholder panel discussions and to provide background information and an overview of the November 2021 Proposal, as well as information on how to effectively engage in the regulatory process. Subsequently, on November 14, 2022, the EPA hosted a call for environmental groups and EJ communities; on November 17, 2022, the EPA held a webinar for both members of tribal nations and communities; and on November 30, 2022, the EPA held a training for Tribal Environmental Professionals.

In response to comments that EPA include new provisions requiring states to include certification and evidence of meaningful engagement in their state plans, see discussion in section XIII.C.6 (Meaningful engagement) of the final rule preamble. In the November 2021 Proposal and December 2022 Supplemental Proposal, the EPA proposed and solicited comment on a requirement that states perform early outreach and meaningful engagement with pertinent stakeholders during the development process of their state plans pursuant to EG 0000c. The EPA is not finalizing the provision for meaningful engagement in this rulemaking. Rather, since similar revisions to subpart Ba are now final and are therefore applicable to the EG 0000c, state plans must be submitted according to the provisions in 40 CFR 60.23a(i) which requires states to document in their plan submittals how they provided meaningful engagement with the pertinent stakeholders. Specifically, subpart Ba requires as part of completeness criteria in 40 CFR 60.27a(g) that states must submit, with the plan or revision, documentation of meaningful engagement including a list of identified pertinent stakeholders and/or their representatives, a summary of the engagement conducted, a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions.

Comment: Commenter (2257-MOGA) expresses concern with the proposed exemptions of Bureau of Land Management (BLM) properties from requirements applied to private land wells and facilities. The commenter questions why EPA provides an exemption on BLM lands that leads to increased emissions on underserved communities if the intent is to reduce emissions and protect underserved communities. The commenter believes that this is a double standard for emission reduction regulations when applied to current and future proposed NSPS and Environmental Justice initiatives. The exemption of emissions on BLM lands allows thief hatches to be opened to accurately measure production, to ensure the federal government is able to accurately assess production for consideration of royalty payments without operational pressures pushing storage tank volumes downward. The commenter states that this exemption is not consistent with the EPA and Biden Administration's intent to reduce or eliminate fugitive

emissions, nor does this rule adhere to or facilitate the administration's Environmental Justice initiative for under-served communities which includes tribal lands. The commenter notes that these practices are not permissible for producers on private land and would violate current and future NSPS regulations in addition to proposed future EPA Emission Guidelines for existing facilities.

Response II-21-8: The EPA does not agree with the premise of the comment with respect to EPA rules as they apply to operators on federal land under BLM oversight. The NSPS is a federal rule authorized under the Clean Air Act as Amended in 1990 and governs air emissions at oil and gas operations under this NSPS subpart OOOOb and OOOOc EG. There is no exemption to these rules for operators on federal lands. The rules are applied and enforced by EPA and BLM for lands under federal jurisdiction, and there is no explicit exemption for operators on BLM lands. BLM's standards align with EPA standards. Where there is the potential to conflict, BLM generally tries to minimize regulatory overlap. Where EPA has adopted requirements that are at least as effective as and would potentially overlap with the provisions of BLM rules, the BLM rules provide a means for operators to comply with the EPA requirements in lieu of the BLM requirements. EPA also notes that EPA rules are not a substitute for independent BLM waste reduction regulations. The EPA rules do not fulfill the BLM's statutory responsibility to reduce waste of public resources.

## **21.5 General Comments on Statutory and Executive Reviews**

Comment: Commenter (2219-WOGCC) asserts that EPA has not appropriately evaluated statutory and executive order reviews. The commenter states that this rule imposes significant burdens on local, small businesses, likely forcing insolvency on many of them. The commenter believes that the insolvency of these companies will result in loss of employment, royalties and taxes in local communities and the state.

Response II-21-9: The EPA disagrees with the comment that EPA has not appropriately evaluated the burden on local and small business. In response to comments on the analyses conducted at proposal, see Volume I, Response I-20-22 in Chapter 20 (Emissions and Regulatory Impacts), subsection 20.2.5 (Economic Impacts), on economic impacts and impacts to production. See also Volume I, Chapter 20 (Emissions and Regulatory Impacts), subsection 20.2.7 (Impact on Small Business), Response I-20-27, for a full discussion of small business impacts. Based on comments received on the November 2021 proposal and December 2022 Supplemental Proposal, the EPA further revised the RIA. EPA directs that commenter to the final RIA sections 4.4.6.2 for the result of the modeling that was performed to estimate the impact of the final rule on such entities.

## **Chapter 22. Appendix K**

The following sections provide a summary of comments received on EPA's proposed protocol for the use of OGI in the determination of leaks as Appendix K.

### **22.1 General Support and Opposition for Appendix K**

#### ***22.1.1 Unnecessary Changes***

Comment: One commenter (2196) argued that EPA designed the Appendix K protocol to determine the presence and location of leaks and not for the Quantitative Optical Gas Imaging (QOGI) process of direct measurement of emission rates from sources. The commenter further stated that changes in the supplemental proposal are devoted to the measurement function and are not necessary for an OGI LDAR program.

Response II-22-1: Although Appendix K is not designed for quantitative OGI, EPA disagrees that the changes made the December 2022 Supplemental Proposal were geared toward QGI cameras or to the measurement function of QOGI cameras. The changes made in the December 2022 Supplemental Proposal were made in response to comments received on the November 2021 Proposal and are applicable to cameras used in qualitatively determining the presence of leaks.

#### ***22.1.2 Unnecessary Performance Assurances***

Comment: Two commenters (2366, 2483) stated that the protocol's performance assurances are excessive and can be supplanted by demonstrating a properly working infrared camera application.

Response II-22-2: EPA disagrees with that the included performance assurances are unnecessary. While EPA agrees that it is important that an OGI camera operator be able to show that the infrared camera is working properly, how an operator is trained and uses the camera in the field is critical to finding leaks with an OGI camera. Therefore, it is necessary for OGI camera operators to prove initial and continued competency with an OGI camera to ensure that the operator can find leaks.

#### ***22.1.3 Support for Scope of Appendix K***

Comment: One commenter (2305) acknowledged and supported the removal of the requirement to use Appendix K for OGI surveys in the Transmission and Gathering & Boosting sectors.

Response II-22-3: EPA acknowledges the commenter's support.

#### ***22.1.4 Support for Use of Appendix K in Subparts Beyond NSPS 0000b***

Comment: One commenter (2428) recommended that EPA amend 40 CFR part 63 subpart CC such that the use of OGI technology and Appendix K are allowed as an alternative to Method 21 for petroleum refineries. Approval as an alternative would reduce both industry and Agency

resources associated with the preparation and approval of Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI. The commenter expressed preference for an amended subpart CC over the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in the General Provisions of part 60 and part 63. The commenter further stated that other part 60 and 63 standards should also be modified to make Appendix K an option for industry sectors beyond refineries.

Response II-22-4: This comment on updating subparts other than NSPS OOOO, NSPS OOOOa, NSPS OOOOb, and EG OOOOc is outside the scope of this rulemaking.

## **22.2 Definitions and Terminology**

### ***22.2.1 OGI Camera Operator***

Comment: Some commenters (2446, 2535) requested that EPA consider adding a definition for “OGI camera operator/camera operator/trained OGI camera operator” as “a camera operator that does not yet meet the definition of a ‘Senior OGI camera operator’ but has completed the training specified in section 10.”

Response II-22-5: EPA is adding a definition of “OGI camera operator” to Appendix K, which is defined as someone who has completed the training required in section 10 of Appendix K and has passed the final survey test. Additionally, EPA notes that a senior OGI camera operator is a subcategory of OGI camera operator.

### ***22.2.2 Senior OGI Camera Operator***

Comment: One commenter (2177) requested that EPA clarify the duration in the definition of “survey hours” and whether this aligns with “dwell time” or “monitoring survey” hours. The commenter similarly requested that EPA clarify “at least 2 hours” in section 10.2.2.4.

Response II-22-6: EPA has added a definition of “survey hours” to Appendix K. A survey hour is the accumulation of 60 minutes of conducting a survey with an OGI camera. Rest breaks are not included in a survey hour. The 60 minutes do not need to be consecutive to constitute a survey hour. EPA is also clarifying that the final test in section 10.2.2.4 must consist of 2 survey hours.

EPA notes that the version of Appendix K in the December 2022 Supplemental Proposal did not use the terminology “monitoring survey hours”. Dwell time is the time spent looking at a particular scene before moving to the next scene. Dwell time is active survey time and would count towards a survey hour.

### ***22.2.3 Delta Temperature (delta-T)***

Comment: One commenter (2196) contends that the assumption outlined in section 3.0 that emission process gas temperature is equal to ambient air temperature is not an acceptable practice. The commenter noted that in the field the emitted process gas is commonly a different temperature than ambient and asked that the last sentence of this definition be deleted.

Response II-22-7: EPA disagrees with the commenter. Gases cool rapidly upon expansion when released and approach ambient temperature close to the release point. This is also why cloudy days tend to pose more difficulty than sunny days, as the cloud temperature profile will be closer to ambient than that of the unobstructed sky.

## **22.3 OGI Camera Specifications**

### ***22.3.1 Camera Configurations for Initial Certification***

Comment: One commenter (2421) requested that section 6.1.2 be expanded to require an indication of the configuration mode used to test the technology. This detail would encourage conformity between manufacturer and the testing facility. Specifically, if a technology provider tests in an enhanced imaging mode for compliance with 6.1.2 but operators use the technology in a less sensitive mode, the technology could easily miss intended leaks due to inappropriate application in the field.

Response II-22-8: EPA acknowledges the commenter's concern regarding initial specification testing. However, we do not consider it necessary to add this level of specificity to Appendix K to allow for future technology development flexibility. Development of the operating envelope will prevent an OGI camera operator from using a mode that cannot meet the specified sensitivity requirements.

Comment: One commenter (2399) recommended that section 6.1.2 be revised to expand the detectable viewing distance of 17 grams per hour of methane emissions beyond two meters. An advantage of OGI cameras is that it reduces the need to elevate monitoring personnel by two meters or more to monitor "difficult to monitor" components.

Response II-22-9: EPA notes the intent of section 6.1.2 is to set a standard bar that all OGI cameras must achieve, not to restrict all OGI surveys to two meters viewing distance. Section 6.1.2 is an initial demonstration of capability of an OGI camera model. Section 8, development of the operating envelope, is used to determine the maximum distance for viewing components under specific field conditions.

### ***22.3.2 Detection Limits***

Comment: One commenter (2421) agreed with the new minimum detection level of butane as 5 g/hr but questioned the level of detection for propane. The commenter stated that the foundation of Appendix K and optical gas imaging as a technology is based on the response factors (RF), per Section 6.1.1 and Annex 1 of Appendix K. Therefore, the commenter states that propane (a compound with a RF of 1.000) should not have a detection threshold higher than methane (a compound with a RF of 0.297). The commenter recommended that propane have a minimum detection level similar to butane, 5 g/hr, since it is also over 3.3 times more absorptive for the defined technology in the spectral range of the technology, and the commenter suggested that all references to the minimum detection threshold of propane in section 8 also be changed to 5 g/hr.

Another commenter (2428) questioned why a lower mass rate criteria was selected for butane when the response factor for butane and propane are almost identical. The commenter stated that this seems inconsistent with the language in section 1.2, which allows for the average response factor approach with respect to propane.

Response II-22-10: See discussion in section XIV.A.2 of the preamble to the final rule which details EPA's final standards related to OGI camera detection limits.

### ***22.3.3 Equipment Needed for Certification Testing***

Comment: One commenter (2465) objected to the accuracy requirements of ancillary meteorology equipment used for the initial verification test. The commenter specifically objected to sections 6.2.6.2 and 6.2.6.3, which require an accuracy of 1.0 mbar or less with a resolution of 0.1 mbar for ambient pressure measurement and an accuracy 0.2 m/s and a minimum range of 0.1 to 20 m/s for wind speed measurement. The commenter stated that if the measurement frequency is once every hour as described in section 6.2.6, the change in time is much larger than the accuracy. The commenter requested an accuracy of 5.0 mbar with a resolution of 1.0 mbar for ambient pressure measurement and an accuracy of 1.0 m/s and a minimum range of 0.1 to 20 m/s for wind speed.

Response II-22-11: EPA agrees with the commenter and has implemented the requested changes.

Comment: One commenter (2196) requested that EPA remove the wind direction and humidity requirements of sections 6.2.6.4 and 6.2.6.5.

Response II-22-12: EPA disagrees with the commenter. Wind direction and humidity are critical measurements, and as such, we are maintaining the requirement to monitor these requirements as part of the initial camera model demonstration.

### ***22.3.4 Sensitivity Requirement***

Comment: Two commenters (2366, 2483) notes that EPA revised the Scope section of Appendix K to apply more broadly, but for transmission and storage applications, the added complexity of including propane and butane is not warranted because those constituents are present at low levels (<1%) and the majority of the gas (>90%) is methane. The commenters further stated that the method should provide for a sector-specific performance test verification gas composition and analyte flowrate.

Response II-22-13: In the December 2022 Supplemental Proposal, EPA only required the use of Appendix K for OGI surveys at gas processing plants. Sections of gas processing plants contain appreciable amounts of volatile organic compounds (VOC), and as such, it is important that an OGI camera used for leak inspection at these sources be able to identify VOC leaks. Therefore, EPA disagrees with the commenter that adding a specification for butane or propane is unwarranted for OGI cameras used on these sources. For upstream oil and gas sources other than gas processing plants, EPA is not requiring the use of Appendix K.



EPA also notes that sector-specific performance requirements can be considered on a regulation specific basis when EPA revised a subpart to reference Appendix K. Such sector-specific performance requirements would be defined in the referencing subpart and not in Appendix K.

## 22.4 Operator Training

### 22.4.1 General Opposition on Training Requirements

Comment: Several commenters (2177, 2220, 2248, 2366, 2483) indicated that the training requirements are excessive and too burdensome. One commenter (2366) stated that the initial training, refresher training, quarterly audits, and documentation requirements are unnecessary, unsupported, and too burdensome to implement for a simple leak screening method. Another commenter (2421) objected to EPA's reliance on a single field study<sup>1</sup> to develop the "onerous" training requirements and asserted that EPA should provide additional data to support the requirements.

Response II-22-14: EPA disagrees that the training requirements are excessive. Additionally, EPA notes that the training requirements were not based on the cited study but were developed based on the outcome of the Appendix K workshop held in November 2020 and were further refined based on the comments received on the November 2021 Proposal. Proper training is critical for the development of an OGI camera operator's ability to detect leaks and continuing audits are necessary to assess continued proficiency. This is similar to EPA Method 9, which requires opacity observers to recertify every 6 months.

Comment: Some commenters (2286, 2429) expressed concern that there may be very few experts available to oversee training. One commenter (2286) stated that due to the level of credentials and experience required, there may be a shortage of expertise, especially for natural gas processing plants who may currently comply with the requirements of NSPS OOOO and OOOOa. These plants would have to revise their LDAR programs and would need to complete initial and ongoing inspections. Another commenter (2429) stated that the burden of the requirements may make it more difficult to hire, train, and retain inspectors in the field.

Response II-22-15: Based on the grandfathering provisions that were added to the December 2022 Supplemental Proposal, EPA believes that there should not be a shortage of senior OGI camera operators. However, we note that gas processing plants can continue to use EPA Method 21 if they do not wish to update their LDAR programs. EPA anticipates those OGI camera operators who initially qualify as senior OGI camera operators will be interested in conducting training and auditing initially because some of the time spent training and auditing OGI camera operators also counts towards their time requirements to maintain their senior OGI camera operator designation under Appendix K.

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<sup>1</sup> The commenter Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., Thoma, E. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. *Environ. Sci. Technol.* 54(18), 11506 – 11514. <https://doi.org/10.1021/acs.est.0c01285>.

### ***22.4.2 Recertification Requirements***

Comment: One commenter (2177) stated that the retraining and classroom requirements in section 10.5 are arbitrarily stringent; the commenter suggested that an OGI operator with previous experience should only be required to attend a refresher training if they have not conducted monitoring within the last 12 months.

Response II-22-16: EPA notes that in the December 2022 Supplemental Proposal, the recertification requirements in section 10.5 were changed to require retraining instead of the full initial training. EPA contends that it is reasonable to require an operator who has not recently conducted a survey to attend a refresher training and that the retraining is equivalent to a refresher training.

### ***22.4.3 Initial Training Requirements for Experienced Camera Operators***

Comment: One commenter (2177) asked EPA to clarify the requirements in section 10.6.2 to indicate whether the “40 hours of experience” required of OGI camera operators is intended to align with “dwell time” or “monitoring survey” time.

Response II-22-17: The 40 hours of experience refers to 40 survey hours. A survey hour is defined as 60 minutes of active survey time. Dwell time is the time spent looking at a particular scene before moving to the next scene. Dwell time is active survey time and is, therefore, inherently a part of the monitoring survey time.

### ***22.4.4 Classroom Training Requirements***

Comment: Some commenters (2139, 2421) recommended that EPA clarify the standards for OGI classroom instruction. One commenter (2421) noted that Appendix K does not describe who is qualified to conduct classroom training; the commenter urged that this should not be senior OGI camera operators, whose level of expertise is needed in the field, but by someone with previously experience in classroom training. Commenter (2139) requested that EPA define additional requirements for an OGI instructor, including (1) 2 years minimum experience developing or delivering content (including the topics in sections 10.2.1.1 through 10.2.1.8); (2) certification to a minimum of Infrared Thermographer Level II with recertification every 2 years; (3) 100 hours of career instructional classroom experience including 20 hours within the last 12 months; and (4) an option to “grandfather” requirements for OGI instructors that already meet the requirements of (1) through (3).

Response II-22-18: EPA disagrees with the commenters and is not including additional requirements for qualifying OGI instructors. EPA recognizes that there are OGI camera operators or other personnel that are qualified to conduct classroom training on the basic operation of OGI cameras other than those that meet the qualifications outlined by the commenters, and we do not want to restrict the capability of owners and operators to use those personnel. EPA does note that a senior OGI camera operator may give or develop the classroom training, but the classroom training is not required to be developed or given by a senior OGI camera operator.

Comment: One commenter (2139) provided specific comments on the duration of classroom instruction on specific topics. The commenter noted that there is no definition of the total required number of hours of classroom instruction, no requirement for number of hours for each element listed in sections 10.2.1.1 through 10.2.1.8, no identification of a method of instruction, and no requirements for testing or proof of classroom training comprehension. The commenter recommended that EPA require a minimum of 16 hours of classroom instruction covering the topics in sections 10.2.1.1 through 10.2.1.8, a minimum of 8 hours each for Basic Science and Camera Operation and Image Interpretation, Regulations, and Documentation, and a minimum pass score of 80 percent (consistent with ASNT SNT-TC-1A (2022)<sup>2</sup>). Commenters (2139, 2248) also requested that EPA clarify that the instruction may be led in-person within a classroom or instructor led online and that EPA specifically provide a definition of “classroom.”

Response II-22-19: EPA has not prescribed a minimum time for the initial training. It is more important that the training cover the required topics than for the training to last a set amount of time. Additionally, EPA is not requiring a final test for the classroom training. While the classroom training is important, we consider the final field test, which incorporates the information learned in the classroom, to be the true assessment of an OGI camera operator’s abilities. Requiring one final test at the end of training strikes a balance between the burden of initial training and the necessity of ensuring that OGI camera operators are adequately trained.

EPA notes that in the December 2022 Supplemental Proposal, section 10.2.1 of Appendix K stated that classroom training can be at a physical location or online, which addresses the commenters’ concerns, and we do not believe an actual definition of classroom training is necessary. The online training does not need to be live, as long as the trainee has access to all of the materials, the training covers the required subjects, and the trainee has access to the trainer for any questions that they may have on topics covered in the training.

Comment: One commenter (2129) requested that the biennial refresher training be shorter than the initial training, and recommended the refresher training included a minimum time of 2 hours that could be performed in a classroom or online.

Response II-22-20: EPA has not prescribed a minimum time for the biennial refresher training. It is more important that the training cover the required topics than for the training to last a set amount of time. EPA notes that both the initial and the biennial refresher training can be conducted in-person or online.

#### ***22.4.5 Initial Field Training***

Comment: Several commenters (2177, 2196, 2428) remarked on the duration of the training requirements in section 10.2.2. One commenter (2177) stated the requirements would take an entire week or possibly longer if there are multiple trainees. The commenter stated that mandating a minimum of 3 survey hours for observation, a minimum of 12 side-by-side survey

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<sup>2</sup> The American Society for Nondestructive Testing recommended practice number SNT-TC-1A: “Personnel Qualification and Certification in Nondestructive Testing.” Available at <https://www.asnt.org/MajorSiteSections/Standards/SNT-TC-1A.aspx> on July 11, 2023.

hours, 15 supervised survey hours, and 2 survey hours for testing is unnecessarily burdensome, noting that EPA's requirements don't account for the actual hours that would be needed due to fatigue limitations. The commenter suggested that a total of four supervised hours should be sufficient, with a minimum of 30 minutes of survey time for the final test. Another commenter (2428) requested that EPA avoid specific hourly requirements for each training phase; the commenter attested that it would be more appropriate to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys, without prescriptive hours. The commenter stated that this flexibility would allow instruction to be tailored to trainee needs, and as long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, it should be sufficient.

A third commenter (2196), referring to the November 2021 proposed duration requirements of section 10.2.2 which were provided by number of site surveys (subsequently repropose as hours in the December 2022 Supplemental Proposal), provided estimates of the duration required in terms of days, citing the differences in facility operations and sizes. The commenter estimated that the trainee observation period should take approximately 2 days, the side-by-side comparative survey should take 5 days, and the independent trainee survey with senior OGI camera operator oversight should take 5 days. The commenter recommended the number of days be added to the training program as an option in lieu of number of sites.

Response II-22-21: EPA disagrees that the initial field training requirements are unnecessarily burdensome. Proper training is critical for the development of an OGI camera operator's ability to detect leaks. Four hours of supervised monitoring is not enough training for an average OGI camera operator to be proficient in finding leaks. The training requirements were developed based on the outcome of the Appendix K workshop held in November 2020 and were further refined based on the comments received on the November 2021 Proposal.

EPA also disagrees that the number of survey hours should not be broken into the three different levels. There is merit for all trainees to conduct surveys in each of the three levels, progressing from observation to independent monitoring. While EPA understands that training needs to be tailored to individual trainees, we note that the survey hours specified at each level are a minimum requirement. Trainers are highly encouraged to increase the time spent at any level where it is deemed to be appropriate for an individual trainee.

In regards to providing the requirements in survey days in lieu of number of sites, the change that was made in the December 2022 Supplemental Proposal to make the requirement in terms of survey hours instead of number of sites should provide the flexibility requested by the commenter.

Comment: One commenter (2177) stated that the repeat test in section 10.2.2.5 if a trainee doesn't pass the monitoring survey test is unnecessary and should remain optional.

Response II-22-22: EPA disagrees with the commenter. It is important that an OGI camera operator have a demonstrated ability to locate leaks with an OGI camera prior to conducting surveys that will be used to demonstrate compliance with leak detection programs.

#### ***22.4.6 Performance Audits for Camera Operators***

Comment: One commenter (2177) objected to the duration of the performance audit requirements of sections 10.4.1.1 (comparative monitoring) and 10.4.2 (video review), each of which require 2 hours of survey footage. The commenter expressed that a survey of a simple facility may only require a few minutes due to a minimal number of components. The commenter suggested that the comparative monitoring should only require the senior OGI camera operator to survey the same site without a specific duration. The commenter further pointed out that the requirements of section 10.4.2 conflict with the leak monitoring requirements of 9.7 and 9.7.1, one of which states no footage is required for non-leaking components and the latter which allows recording a photo in lieu of a video. The commenter urged that the time requirements of 10.4.2.1 should be removed as it may be impossible to compile 2 hours of video every quarter due to lack of actual leaks, which would likely incentivize a camera operator to dedicate more time to recording longer videos of found leaks and less time identifying unknown leaks.

Response II-22-23: EPA disagrees with the commenter that there is a conflict between the auditing requirements and the allowance in section 9.7 to only record images of leaks. There is nothing in section 9.7 that would preclude a camera operator from recording non-leaking components or an entire survey, as long as they record the leaking components. Additionally, the two-hour requirement for the performance audit can be accomplished via comparative monitoring or unedited video review, so if the audit is done via comparative monitoring, there is no requirement to record the whole two-hour audit.

Additionally, EPA notes that the two-hour video review should not be composed of video footage of only leaks. Instead, the camera operator being audited should record 120 minutes of actual survey time (not just leaks) so that the survey technique is evident to the reviewer. If the sites being surveyed are such that multiple sites are needed to accumulate 120 minutes of OGI survey process footage, then multiple videos containing unedited and uncut video recording of each complete site survey are allowed to be submitted to the senior OGI camera operator for review.

Comment: Several commenters (2177, 2258, 2483) opposed the quarterly frequency of the performance audits. Commenters (2217, 2258) suggested that the audit requirements should be conducted annually. Some commenters (2428, 2177) responded to the EPA's request for input on a reduced performance audit frequency for certain operators. One commenter (2428) noted that in the initial stages of OGI monitoring implementation, more frequent performance audits are key in ensuring technician efficacy, however, technician monitoring proficiency will increase quickly over time with monitoring and survey experience. Commenters (2177, 2428) asserted that for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A commenter (2177) recommended that OGI camera operators who demonstrate continuing proficiency and accuracy (e.g., operators who do not have significant deficiencies during two consecutive performance audits) should have reduced performance audit frequencies. Another commenter (2428) recommended that EPA adopt a "skip period" approach, as follows: for technicians who pass four consecutive quarterly performance audits, the audit interval should be extended to semiannual, for technicians who pass two consecutive semiannual performance audits, the audit interval should be extended to

annual. The commenter noted that if a technician does not pass a semiannual or annual audit or does not conduct a monitoring survey during the previous 12 months per section 10.5 of Appendix K, then quarterly performance audits should be restarted.

Response II-22-24: EPA understands the concerns raised by the commenter and agrees that experienced OGI camera operators should not need to undergo a quarterly performance audit. While EPA considers a performance-based (or “skip period”) approach a valid option, we are concerned that implementing this type of approach would be complicated for compliance and recordkeeping purposes. As such, EPA has determined that the best path forward is to maintain a uniform performance audit frequency for all OGI camera operators, but to reduce the performance audit frequency to semiannual, which is the same frequency as the recertification requirements of EPA Method 9. This decision will also reduce burden and operational challenges associated with locating senior OGI camera operators, especially for small businesses.

Comment: One commenter (2362) questioned why the performance audit would allow OGI operators to miss up to 10 percent of leaks in the final field test and performance audits and objected that EPA has not rationally explained these requirements. The commenter asserted that 10 percent missed leaks could lead to large fugitive emissions of VOCs and methane and would not constitute BSER.

Response II-22-25: EPA notes that this change was made in response to comments received on the November 2021 Proposal and was discussed in the December 2022 Supplemental Proposal.<sup>3</sup> If less than 10 leaks are found by a senior OGI camera operator during a field test or performance audit, the trainee or auditee would need to find all the leaks to pass. However, in situations where there are numerous leaks, EPA decided it was appropriate to allow a “pass” percentage. This acknowledges the fact that OGI is a subjective technique, and that it is difficult for two people to always see the exact same thing, even when both operators are trained. A slight change in conditions or vantage point can affect the operator’s ability to view leaks. While EPA expects camera operators to adjust as necessary to see leaks, it is important to acknowledge there may be instances where one operator will miss a leak seen by another operator. We also note that it is entirely possible that the trainee or auditee may find more leaks than the senior OGI camera operator. The importance of the OGI camera operator’s technique is why we are maintaining performance audits for all operators, even experienced operators.

Comment: One commenter (2177) objected to the retraining requirements of 10.4.3.2 through 10.4.3.4; the commenter stressed that these requirements would force a company to dedicate at least two full time employees for almost a full week (each requiring more than an entire workday with no breaks, and more for testing and travel time) solely to retrain a single camera operator.

Response II-22-26: EPA notes that retraining requires 18 hours of survey time (16 of training, 2 of testing). Even adding in time for rest breaks, this equates to less than a work week. While we understand the commenter’s concern regarding the time commitment, it is essential that OGI

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<sup>3</sup> 87 FR 74838 (December 6, 2022).

camera operators be able to find leaks on a routine basis. If the operator is unable to pass a performance audit, there is no assurance that the operator is finding leaks during routine surveys.

#### ***22.4.7 Senior OGI Camera Operators***

Comment: One commenter (2220) expressed concern regarding the definition of senior OGI camera operator. The commenter was concerned that state agencies would be required to redirect staff resources and potentially encounter higher travel costs to meet the requirements outlined in Appendix K, which would potentially inhibit an agency's ability to meet other compliance obligations.

Response II-22-27: Personnel in federal, state, and local government agencies performing oversight duties are not required to meet the requirements outlined in Appendix K. The rigor of Appendix K is intended to ensure that owners or operators (or their contractors) conducting leak surveys are properly trained and conduct surveys in a manner to minimize the incidence of not finding leaks that are present. The occurrence of false leaks with an OGI camera is a much less likely scenario and can easily be guarded against by a general understanding of interferences that can occur during an OGI survey. Therefore, the only issue that arises from agency personnel not being trained to the rigor of Appendix K is that the agency personnel may not find all of the leaks that are present at the site, although they should be able to find the largest leaks with a basic level of OGI training.

Comment: Two commenters (2220, 2399) expressed concern about a potential lack of qualified senior OGI camera operators. One commenter (2220) stated that the number of qualified senior OGI camera operators is limited based on the requirements of Appendix K and the process of achieving such a qualification. Another commenter (2399) appreciated that the December 2022 Supplemental Proposal considered comments on the November 2021 Proposal and revised the senior OGI camera operator requirements. However, the commenter urged EPA to make further revisions, due to concerns with respect to the scarcity of operators that could qualify as senior OGI camera operators. The commenter stated that the requirements hinder midstream industry in-house personnel from qualifying as senior OGI camera operators. Additionally, because there is work that only senior OGI camera operators can perform, and initially there will be a small number of qualified operators available, senior OGI camera operators are likely to be very costly, if they are available at all. The commenter further stated that even with the revised requirements, it will likely take years to qualify enough senior OGI camera operators to meet regulated industries' training, auditing, and survey needs.

Response II-22-28: EPA acknowledges the commenters' concern. We have made allowances for operators to initially use previous training and experience to alleviate the issues surrounding the lack of senior OGI camera operators. Because an operator can qualify as a senior OGI camera operator after 1400 hours of survey experience (less than one year of full-time surveying), we expect the pool of qualified senior OGI camera operators to greatly increase within a year of promulgation of Appendix K. This should lead to both an increase in availability and a decrease in cost of senior OGI camera operators.

## **22.5 Operating Envelope**

### ***22.5.1 Industry Support***

Comment: One commenter (2428) supported the development of operating envelopes, stating that the “use of pre-defined operating envelopes through testing as prescribed in section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys.”

Response II-22-29: The EPA acknowledges the commenter’s support.

### ***22.5.2 Daily Field Checks Instead of Operating Envelopes***

Comment: One commenter (2305) stated the operating envelope is overly complicated and that daily field checks ensure the camera operator can identify fugitive emissions and set a maximum viewing distance. The commenter suggested that a change in weather that could significantly alter the viewing distance (e.g., large temperature changes of 10 degrees or significant wind changes), could trigger a retest to ensure the viewing distance set point is still adequate to identify fugitive emissions. Another commenter (2428) stated that technicians should already be trained in recognition of factors which would impact the leak detection capability, and that this is already adequately addressed in section 9.2.3. The commenter stated that if conditions are significantly different, then the technicians should switch to another operating envelope or conduct another distance check verification.

The commenter (2428) maintained that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated but urged that a daily or site-specific distance check should remain an option. The commenter acknowledged that there may be times when OGI camera operators will be using an OGI camera that does not yet have any established operating envelopes either because the camera OEM has yet to publish operating envelopes once Appendix K is promulgated, the OGI camera is new to market, or monitoring conditions for a specific survey or site are unique regarding the pre-defined operating envelopes and the camera operator may want to ensure that the delta-T and viewing distance are appropriately set.

Response II-22-30: See discussion in section XIV.A.3 of the preamble to the final rule which details EPA’s final standards related to daily field checks in lieu of an operating envelope.

### ***22.5.3 Configuration Concerns***

Comment: One commenter (2399) reiterated the comments they provided in response to the November 2021 Proposal regarding the camera performance criteria in proposed section 8 of Appendix K. The commenter states the requirements are not suitable for surveying locations in the remote or rural areas where gas plants often operate. The commenter also stated that the initial performance verification requirements under Appendix K section 6.1.2 conflict with the requirement to establish operating envelopes detailed in sections 8.3 and 8.4. The commenter also noted that requirements in sections 8.3 and 8.4 instruct the establishment of operating



envelopes for potentially hundreds of different configurations. Because each configuration requires time to establish and test, the commenter argued that these requirements bog down operators and discourage the use of OGI cameras.

Response II-22-31: EPA disagrees with the commenter that section 6.1.2 conflicts with sections 8.3 and 8.4 of Appendix K. The intent of section 6.1.2 is to set a standard bar that all OGI cameras must achieve and is an initial demonstration of the capability of an OGI camera model. Section 8 is used to determine the different field conditions (distance, wind speed, and delta-T) under which a trained observer should be able to identify leaks.

Development of operating envelopes is likely to occur well in advance of a planned survey. Additionally, as the operating envelope is specific to a camera model, it is unlikely that each owner or operator would have to develop their own operating envelopes, unless there is a site-specific reason to do so. As such, EPA does not agree that operators will be bogged down with establishing operating envelopes.

Comment: One commenter (2421) argued the terminology of “all potential configurations” in section 8.3 is too vague to cover realistic testing situations and recommended a word change to “common field use configurations.” The commenter appealed for clarity regarding camera alternate color palettes and high sensitivity mode and whether these configurations require a defined operating envelope.

Response II-22-32: EPA understands the commenter’s concern, but does not agree with the change in terminology, as common field configuration is a more vague term than what is currently in Appendix K. EPA is not defining a list of configurations that must be tested for an operating envelope, because we do not want to inadvertently exclude any potential future OGI camera from Appendix K by being overly prescriptive in the listing of configurations. Instead, as noted in the December 2022 Supplemental Proposal, we are requiring testing for operating envelopes in all potential configurations that could impact the detection limit. If a configuration does not impact the detection limit, there should be documentation to support that assertion. If a particular configuration will not be used in the field to conduct surveys, an operating envelope is not needed for that configuration.

For alternate color palettes, the camera operator (with or without help from the camera manufacturer) needs to determine whether the change in color palette affects the detection limit. A high sensitivity mode would be expected to affect the detection limit.

#### ***22.5.4 Observers***

Comment: Commenters (2535, 2446) requested that the language in section 8.5.3 be clarified. Commenter questioned whether each location is required to have 4 trained OGI camera operators.

Response II-22-33: Development of the operating envelopes is likely to occur well in advance of a planned survey. Additionally, as the operating envelope is specific to a camera model, it is unlikely that each owner or operator would have to develop their own operating envelopes.

Therefore, EPA does not anticipate that it will be necessary for every site to have 4 OGI camera operators.

If a facility has a situation that requires a unique operating envelop to be developed, then it is expected that this process will occur with enough time to gather a panel of four observers either at a testing location or at the facility location. EPA notes that the observers are not required to be senior OGI camera operators. Additionally, the observers do not have to be trained in accordance with Appendix K, although we caution that use of an observer who is not trained in accordance with Appendix K may result in reduced operating envelopes because an untrained observer is likely to see less leaks.

## **22.6 Conducting OGI Surveys**

### ***22.6.1 delta-T Monitoring***

Comment: In lieu of verifying the delta-T check function in section 9.1.4 of Appendix K, one commenter (2465) suggested a daily image check with a butane lighter or propane cylinder (which is already required in section 9.1.3) under fixed conditions to reduce the burden of Appendix K. Another commenter (2196) claimed that sections 9.1.4, 9.2.1, and 9.2.2 are unnecessary and should be deleted, maintaining that virtually any background provides a delta-T.

Response II-22-34: EPA notes that verifying the operation of the delta-T check function is only applicable for those cameras that include that function and for those OGI camera operators who will use the function to maintain a minimum delta-T.

Regarding the removal of sections 9.1.4, 9.2.1, and 9.2.2, EPA disagrees and notes that there are many backgrounds where the temperature is nearly the same as the gas, and as such, would not provide an adequate delta-T for monitoring.

Comment: Two commenters (2421, 2428) responded to EPA's request on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function. One commenter (2428) stated that a technician should use the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. If the ambient temperature is known, then it is a simple step to add/subtract the background to determine delta-T. Another commenter (2421) claimed that the comprehensive training, required by Appendix K, should ensure operators will retain an adequate delta-T. The commenter also noted that High Sensitivity Mode increases the sensitivity of the technology to a degree that the delta-T is less relevant.

Response II-22-35: EPA acknowledges the information provided by the commenters. EPA agrees monitoring background temperature and ambient temperature can be used to ensure the camera operator maintains an adequate delta-T.

### ***22.6.2 Dwell Time***

Comment: Commenters (2177, 2258, 2421, 2428, 2196) suggest that dwell time requirements be removed. Commenters felt that the dwell time requirements are overly restrictive and dwell time should be left to the discretion of the operator. These commenters argued that trained operators and the Appendix K protocol, which includes certification requirements and audit requirements, are adequate to demonstrate that operators are capable and qualified to detect leaks without dwell time requirements. One commenter (2248) suggested that dwell time as a concept is more appropriate for Method 21, where the search is focused on an invisible leak. Another commenter (2483) stated that the proposed viewing requirements would increase survey time approximately four-fold.

Commenters (2305, 2421) were critical of the proposed requirement that a component must be imaged from at least two different angles, and the OGI camera operator must dwell on each angle for a minimum of 2 seconds per component in the field of view. Commenters (2366, 2483) were also critical of the proposed allowance for reduction of the dwell time for complex scenes based on the monitoring area and number of components according to Table 14-1 of Appendix K. These commenters argued that dwell times and angles are unnecessary, burdensome, and impractical to implement.

Some commenters provided suggestions for alternative dwell times, noting that dwell times should be based on scenes since operators are focused on looking for movement in a scene when conducting surveys. One commenter (2305) suggested that a minimum of 3 seconds per scene would be appropriate, while another commenter (2421) recommended a maximum dwell time of 5 seconds per angle of view for scenes with multiple components. A third commenter (2428) suggested that scenes be differentiated according to the number of components being imaged and viewing distance. The commenter stated that an example of a “simple” scene would be a scene of 20-25 components viewed from a distance of 15-25 feet. The commenter stated that this approach offers a high probability of leak detection by a technician and limiting the number of components to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves the ability to detect a leak.

Response II-22-36: See discussion in section XIV.A.1 of the preamble to the final rule which details EPA’s final standards related to dwell time.

Comment: One commenter (2399) stated the concept of establishing a minimum dwell time does not take full advantage of the ability to make OGI the preferred leak detection option at a gas plant. The commenter cited technical literature which tracked scan speed on the unit level (well head, separator, tank) and not on the individual component level.<sup>4</sup> The commenter further stated that an advantage of using OGI cameras under Subpart OOOOa is that individual component counts are not necessary, but under Appendix K, a component driven time requirement disregards a camera operator’s experience and significantly diminishes the benefits of using an OGI camera.

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<sup>4</sup> The commenter cited Zimmerele, et al., Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions, Environ. Sci. Technol. 2020, 54 (18), 11506-11514.

Response II-22-37: In the final version of Appendix K, EPA has updated the dwell time requirement to implement the concept of a simple scene. See discussion in section XIV.A.1 of the preamble to the final rule which details EPA's final standards related to dwell time.

EPA notes that even though Appendix K does take component counts into consideration, it does not require documentation of these component counts to the degree that a Method 21 based leak detection program does. However, EPA maintains that it is still necessary for owners and operators, as well as OGI camera operators, to know all the components regulated by a leak detection program and where all the components are located, as it is important to confirm that each component has been appropriately viewed using the OGI camera.

### ***22.6.3 Rest Breaks***

Comment: Commenters (2196, 2305, 2366, 2399, 2428, 2483) contended that rest break intervals should not be defined by Appendix K, and the requirement in Appendix K is unsupported and arbitrary. One commenter (2428) stated that OSHA already has appropriate guidelines for ergonomics in the workplace which include eye strain.

Commenters (2305, 2399, 2428) argued that camera operators do not look through their cameras for periods longer than 1-2 minutes at a time before the camera is put down so the operator can see their surroundings and walk to the next viewing location. Another commenter (2348) argued that the break duration should be empirically determined, include dwell time, and should be adjusted to consider environmental conditions. Another commenter (2196) reported that it is natural for a technician to take natural breaks after completing one unit or area and before switching to another or after switching levels or after a climb. Further, bodily functions (including hydration & heat relief) and bathroom breaks interrupt sampling and in aggregate are longer than the Appendix K prescribed times.

One commenter (2399) agreed that operators generally need breaks to avoid eye and mental fatigue but suggested that if Appendix K defines a rest break, it should be a 30-minute break after every two hours of monitoring because operators frequently receive breaks while walking through midstream facilities, which typically have a lower density of components. The commenter further noted that this will allow the OGI camera operator to develop a monitoring rhythm and more effectively survey larger facilities.

Response II-22-38: EPA disagrees that a mandated rest break is unsupported and arbitrary. The language for rest breaks that was put into the November 2021 Proposal was derived from EPA Method 9, which is another visual observation method. EPA determined it was appropriate to add a similar requirement for Appendix K because both mental and eye fatigue are known issues that occur with prolonged viewing of components with an OGI camera. Such fatigue may be a safety hazard, and it may also prevent the OGI camera operator from finding leaks that are present.

EPA acknowledges natural breaks will occur at regular intervals when an OGI camera operator moves between process units or process levels and notes that rest breaks are only required if these natural breaks do not occur frequently enough such that the OGI camera operator is

continuously surveying for more than 30 minutes. EPA encourages OGI camera operators to take longer or more frequent rest breaks as needed to reduce the incidence of fatigue.

#### **22.6.4 Monitoring Regulated Components**

Comment: One commenter (2428) stated that while the revised language provided for the monitoring survey methodology affords additional flexibility, the methodology remains limited to three options without any ability for a site to propose an alternative. The commenter (2428) requested that EPA add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified; the commenter contended that a site could propose an alternative to their delegated authority prior to use.

Response II-22-39: EPA is not currently aware of another approach that would effectively ensure an owner or operator monitors all components regulated by a referencing subpart. If an owner or operator develops a new methodology that can achieve this goal, the owner or operator may submit a request for alternative monitoring procedures under 40 CFR 60.13(i) or 40 CFR 63.8(f), as applicable. Additionally, when Appendix K is applied to a specific subpart through a rulemaking, commenters may request that additional methodologies be added for use of Appendix K in that subpart.

### **22.7 Records and Reporting**

#### **22.7.1 Burden**

Comment: One commenter (2248) agreed with clearly stating the recordkeeping requirements within the protocol. However, commenters (2366, 2248, 2196) stated that the recordkeeping requirements are unnecessary and burdensome. One commenter (2196) expressed the opinion that, as written, the method contains “too many compliance traps” due to the recordkeeping burden; the commenter urged that if finalized as is, industry would likely revert to using EPA Method 21 due to this burden.

Response II-22-40: EPA disagrees with commenters. The recordkeeping outlined in Appendix K is necessary to ensure compliance with the various requirements of the protocol, including the training requirements and the conditions under which surveys must be conducted. In the December 2022 Supplemental Proposal, EPA updated the recordkeeping requirements to indicate certain records only need to be available to an owner and operator and made available to a delegated agency upon request.

If an owner or operator wishes to use EPA Method 21 due to recordkeeping associated with Appendix K, use of EPA Method 21 remains an option in NSPS OOOOb and EG OOOOc, which are the only subparts that currently include the use of Appendix K.

Comment: One commenter (2399) pointed to section 9.3.2 of Appendix K as an example of burdensome requirements, noting it would require significant time and effort to “develop visual cues (e.g., tags, streamers, or color-coded pipes) to ensure that all regulated components were monitored.” The commenter notes that establishing a new set of component tags throughout gas plants (and keeping them updated over time) offers no advantage over EPA Method 21 and

discourages OGI camera use. Another commenter (2177) objected to the requirement in section 9.7.2 of Appendix K to tag equipment; the commenter asserted that tagging equipment is not necessary and sometimes not physically or safely possible. The commenter stated a photo of the leaking component and description should be sufficient. The commenter proposed revised text for section 9.7.2 as follows: “Identification of the component associated with each leak must be recorded and stored with the OGI survey records.”

Response II-22-41: EPA notes that section 9.3.2 is one of three options for ensuring all regulated components are monitored. The other options include developing route maps or maps with designated observation points and GPS route tracing. Owners and operators are allowed to choose the option that works best for their site, and as such, we do not anticipate that all owners and operators will be developing visual cues for monitoring components.

The requirement to tag a component for repair is only applicable if the repair cannot be made immediately. A photograph of the component may not be enough to identify the component if there are multiple components in the vicinity of the leak. EPA notes that tagging components is a requirement in most leak detection programs and provides an easy way for a technician to locate the correct component in the field. As such, we are retaining the requirement to tag components that cannot be immediately repaired at the time of inspection.

### ***22.7.2 Video Records***

Comment: Several commenters (2177, 2428, 2446, 2483, 2535) questioned the video and photo capture requirements in sections 9.7, 9.7.1 and 9.7.2 of Appendix K. Commenters (2177, 2428, 2446, 2535) noted that section 9.7 states that no footage is required for non-leaking components and allows the use of a photo versus a video, while section 9.7.1 requires a full video of the monitoring survey and must document the monitoring results for each piece of equipment. Commenters (2325, 2446) suggested revising section 9.7 as follows: “The site must have a procedure for documenting fugitive emissions or leaks found during the monitoring survey according to 9.7.1 or 9.7.2, one of the following approaches. If no emissions are found, no recorded footage is required to demonstrate that the component was not leaking.” Another commenter (2428) stated the full video language should be deleted or revised to clearly state that the full continuous video is an alternative to maintaining leak imagery only. Yet another commenter (2258) expressed concern that the requirement for a full, uninterrupted video could present challenges due to limitations in storage space and the need to charge and change camera batteries; the commenter requested clarification on whether multiple videos would be accepted for a single survey.

One commenter (2177) supported the use of a single photograph for identifying leaking components as sufficient, but urged that some leaks may not be identifiable as a single photo frame depending on the camera configuration used; the commenter proposed that EPA adjust 9.7.1 to focus the text on the leaking component and revise the text to “..or photograph that depicts the component associated with the leak”.

Commenters (2366, 2483) stated that the proposed Appendix K remains inconsistent with the quality criteria in Method 21 and recordkeeping requirements in other methods and LDAR

programs (e.g., short video clip or photograph that depicts the leak and the component associated with the leak.).

Response II-22-42: In the November 2021 Proposal, EPA required a 10-second video clip for each leaking component. Based upon comments on that proposal, in the December 2022 Supplemental Proposal, we changed the recordkeeping to allow a short video clip or photograph to be kept for each leaking component. We also allowed owners and operators to keep a recording of the entire survey instead of individual video clips. However, we realize based on the comments we received in response to the December 2022 Supplemental Proposal that our intent was not clear and that commenters read the revised text to mean that videos of the entire survey were a requirement. To alleviate this confusion, in the final Appendix K, we have largely reverted the text to its origin November 2021 Proposal form but have retained the allowance for photographs to document leaks. Additionally, we have added a sentence to section 9.7.1 of Appendix K that states that a recording of the full survey suffices for the requirement to take individual videos of leaking components.

EPA acknowledges that the requirement to keep video clips or photographs is different from other LDAR programs. However, LDAR is generally performed using EPA Method 21, and during an inspection, the operator documents the EPA Method 21 reading when a leaking component is found. Taking a photograph of a visual OGI image is analogous to documenting the instrument reading when using EPA Method 21.

### ***22.7.3 Quality Assurance Verification Video***

Comment: Commenters (2421, 2428, 2258) reiterated objections to the requirement to include a 5-minute quality assurance verification video in the monitoring plan. Commenters (2421, 2258) urged that the requirement is overly burdensome, unnecessary, and has not been required for previous regulations for similar applications. The commenters (2421, 2258, 2428) explained that this requirement would require extensive data storage for operators and would present challenges in managing this data, without a clearly added benefit. Commenters (2421, 2428) requested the QA verification video requirement be deleted entirely. One commenter (2421) requested that EPA either require training as described in section 10 or require daily QA verification, not both. The commenter remarked that if the EPA requires training, it should honor the operator as trained after completion of the required steps and eliminate any daily QA process. Another commenter (2258) suggested the duration of the video should be based on the completion of required QA verification tasks (i.e., the time to complete all elements described in section 9.1) in lieu of an arbitrary amount of time.

Response II-22-43: EPA considers the requirement for a daily QA video a reasonable alternative to requiring full survey videos. While we agree that it is not necessary to keep a full video of a monitoring survey, it is important to be able to assess each OGI camera operator's technique when reviewing survey records, as the ability to find leaks that are present is dependent on the camera operator's technique. The daily QA video allows someone who is not present for the survey to determine whether an OGI camera operator uses proper technique on a day-to-day basis. This documentation is especially important for a delegated agency to have available in

their review of OGI survey records and to assess whether Appendix K is being properly implemented.

EPA does not consider a 5-minute video clip cost prohibitive, even if the video clip is taken daily. The average size of a 5-minute OGI video clip is approximately 600 megabytes. If a clip is taken each business day of the year, this will equate to approximately 156 gigabytes of data. Cloud storage of files generally runs in the range of \$5-\$10 for a terabyte of storage.

Regarding the suggestion to change the duration of this video requirement, EPA disagrees with the commenter. The intent of the QA video is to evaluate the OGI camera operator's survey process, not to document that the QA verification tasks in section 9.1 of Appendix K have been completed. As such, we are retaining the length of the QA video as 5 minutes.

#### ***22.7.4 Documentation of Ambient Weather Changes***

Comment: One commenter (2366) stated that a requirement to record the weather conditions (ambient temperature, wind speed, relative humidity, and sky conditions) every 2 hours is arbitrary and unsupported. Another commenter (2483) requested that EPA remove requirements related to reporting weather conditions.

Response II-22-44: The EPA disagrees with the commenters and has retained the requirement in Appendix K to record weather conditions at regular intervals. EPA notes that the weather conditions are a relevant component of how a survey is conducted. Wind speed and temperature are directly related to how an OGI camera operator uses the camera's operating envelope, and as such, an operator needs to be always aware of these parameters and any changes in these parameters. Sky conditions are important to understanding the types of backgrounds that may be present during the survey, which is related to the OGI camera operator's ability to find a suitable delta-T. Understanding the conditions of a survey are crucial to anyone who is reviewing the results of a survey, as well as to the person conducting the survey.

## **22.8 Response Factors and Annex 1**

### ***22.8.1 Calculated Response Factors***

Comment: One commenter (2767) noted that the response factors based on the peer reviewed paper by Zeng et al.,<sup>5</sup> need to be calculated using log base 10, not natural log as was used, because the calculations use log base 10 absorption coefficient data.

Response II-22-45: EPA has evaluated the information provided by the commenter and agrees that the response factors should have been calculated using a log base 10 approach. We have revised the response factors we used in developing the detection limits in Appendix K. The

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<sup>5</sup> Zeng, Y., Morris, J., Sanders, A., Mutyala, S., & Zeng, C. (2017). Methods to determine response factors for infrared gas imagers used as quantitative measurement devices. *Journal of the Air & Waste Management Association*, 67(11), 1180-1191.



Appendix K Technical Support Document has been revised using the recalculated response factors.

Comment: One commenter (2767) noted that all relevant compounds (alkanes, alkenes, benzene, toluene, xylene, ethylbenzene) have a response factor of at least 0.25 at 10,000 ppm-m for all known possible filters between 3.2 and 3.5  $\mu\text{m}$ , and as such, there is no need for recalculating or measuring the response factor values for any relevant compound if the spectral range of the bandpass filter of OGI camera is at 3.2-3.4  $\mu\text{m}$ .

Response II-22-46: EPA has purposely made Appendix K openly generic. While we acknowledge that most commercially available midwave infrared OGI cameras on the market today with a high quality 3.2-3.4  $\mu\text{m}$  filter should easily be able to prove that relevant alkanes, alkenes, and aromatics have appropriate response factors, Appendix K is written for OGI cameras of the future as well as those on the market today. It's important that we guarantee the filters on these cameras continue to retain appropriate responses to these chemicals. Therefore, we are retaining the response factor criteria.

### ***22.8.2 Annex 1 Should be a Stand-alone Method***

Comment: Commenters (2366, 2483) observed that Annex 1 contains a detailed method and procedure for determining a response factor. Both commenters argued that Annex 1 should be separated from the OGI method, and published as a stand-alone method (e.g., for the purpose of reference for subsequent optical/remote sensing technology methods) or as an appendage to Appendix K.

Response II-22-47: EPA disagrees with the commenters. If EPA develops additional optical or remote sensing technology methods that would benefit from Appendix K Annex 1, we may update Appendix K to remove Annex 1 at that time. Currently, because there is a link between Appendix K and Annex 1 and Annex 1 only applies to Appendix K, it is prudent that the two pieces remain together.

### ***22.8.3 Pixel Count for Each Measurement Area***

Comment: One commenter (2457) noted that section 1.1.2 of Annex 1 to Appendix K states that there will be three different areas representing the reference cell, gas cell, and the raw blackbody surface and that these three areas should be uniform and avoid the edges of the inner wall of the reference cell and the gas cell. The commenter further noted that the pixel count for each area was proposed to be at a minimum of 1% of the total pixels of the detector, which the commenter calculated to be a 32 x 24 pixel region. Given that the active surface area of a typical blackbody is small (about 10 x 10 inches), the commenter recommended reducing the minimum size of the three uniform measurement areas from 1% to 0.5%. The commenter stated that this reduction will still provide a sufficient area for each of the three measurements.

Response II-22-48: EPA agrees with the commenter and has implemented this change.

#### **22.8.4 Measurement Data Set**

Comment: One commenter (2457) noted that section 1.1.3 of Annex 1 to Appendix K requires a minimum of 31 measurements, which is assumed to take 31 seconds for a 1 Hz device. The commenter explained that common OGI cameras have a frame rate much higher than 1 Hz, e.g., 30 Hz. The commenter stated that in such a case, only 1 second of data would need to be collected, and this duration may be too short to get a stable and representative reading. The commenter contended that it would be better to specify a minimum of 30 seconds data collection or 30 independent measurements, whichever requires more time.

Response II-22-49: EPA agrees with the commenter that 1 second is too short of a period to get a stable and representative reading. We have revised the requirement in paragraph 1.1.3 of Annex 1 to require a measurement data set of 1,000 data points. Based on the information provided by the commenter, this should take just over 30 seconds for most common OGI cameras, which is consistent with what we originally intended.

#### **22.8.5 Error with the Response Factor Equation**

Comment: One commenter (2457) stated that the response factor equation contained in paragraph 6.2 of Annex 1 to Appendix K is incorrect and should be:

$$RF = \frac{[I_{Blackbody} - (I_{Compound\ of\ Interest} - I_{Gas\ Cell})]}{[I_{Blackbody} - (I_{Reference\ Compound} - I_{Reference\ Cell})]}$$

Where “ $I_{Blackbody}$ ” is the average of the IR radiance pixel area for the blackbody surface over the measurement set.

Response II-22-50: EPA has updated the equation in Annex 1 as suggested by the commenter.

#### **22.8.6 Alternative to Annex 1**

Comment: One commenter (2767) was concerned about the wide use of response factors, including in section 1.2. The commenter stated that the response factor requirement is very specific to a spectral range of a current common bandpass filter (i.e., 3.2 to 3.5 micrometers) and is relative to a camera’s sensitivity to propane. The commenter noted that a response factor is not a measure of absolute response sensitivity of an OGI camera, and therefore it should not be presented as such. The commenter further stated that because response factor criteria is manufacturer specific it should not appear in the protocol.

proposed an alternative method to Annex 1. The commenter stated that the response factor is a ratio of compound specific responses of the target gas to an arbitrary reference gas and maintained that measuring an absolute response criterion is a better method to measure the sensitivity of an OGI camera. The commenter recommended using what they call the compound specific response (CSR). The CSR is determined using the CSR function provided:

$$CSR[CL] = \int_{\lambda_1}^{\lambda_2} [(1 - 10^{-\alpha(\lambda)CL}) \cdot t(\lambda)] d\lambda$$

Where:

- $t(\lambda)$  – bandpass filter transmission as a function of wavelength (between  $\lambda_1$  and  $\lambda_2$ )
- $\alpha(\lambda)$  – absorption coefficient spectrum in  $\text{ppm}^{-1}\text{m}^{-1}$  measured in base-10 absorbance

The commenter (2767) proposed a simplified protocol where an average  $\Delta I$  (or camera response between background radiance and gas plume radiance) threshold determines in what  $\Delta T$  cut-off conditions the camera can be used. For example, the requirement could mandate that only OGI cameras that have an average factor of 5 difference in response between the gas radiance and the blackbody background radiance at a  $\Delta T$  of  $\pm 2$  K are applicable.

Response II-22-51: EPA continues to believe that specifying a response factor threshold in Appendix K is necessary for ensuring that a camera can see the compounds that are included in the emissions stream and for verifying that a camera meets a minimum performance threshold. However, EPA acknowledges the method provided by the commenter could be a valid alternative to Annex 1 of Appendix K. EPA needs additional time and information to fully evaluate this alternative and develop it into a complete protocol. Furthermore, EPA is concerned with finalizing this alternative without first providing notice and taking comment on it. EPA notes that we will continue to review the information provided by the commenter, and if appropriate, Appendix K will be amended in a future rulemaking to incorporate the alternative, possibly as Annex 2 of Appendix K.

## 22.9 Other Comments

### 22.9.1 General Comments

Comment: Several commenters (2248, 2535, 2399) generally supported the revised changes to Appendix K, but some commenters (2535, 2483) had concerns with the appendix as drafted and felt that significant edits were still necessary. Specifically, one commenter (2483) asserted that EPA retained onerous training, certification, and other test method requirements, including initial training, refresher training, quarterly two-hour performance audits, and other documentation requirements that should be revised.

Other commenters (2248, 2399) urged that the appendix is drafted in a way that would discourage its use over Method 21 monitoring, especially at natural gas processing plants. One commenter (2399) stated that Appendix K "is overly rigid with respect to everything from dwell times to break times, robbing it of any improved efficiencies over Method 21."

Response II-22-52: EPA disagrees with the commenters that Appendix K does not provide improved efficiencies over EPA Method 21. An OGI survey using Appendix K can provide reduced monitoring times because multiple components can be viewed simultaneously, operators do not need to physically move in between all components, and operators may not need to climb ladders to reach components. An OGI survey also provides advantages of increased safety

because personnel can view components from a distance and may not need to be elevated to view components. These advantages alone may lead an owner or operator to opt to perform monitoring surveys with OGI instead of EPA Method 21.

EPA acknowledges that there are extensive training and auditing requirements in Appendix K because operator training is critical to developing the ability to see leaks with an OGI camera. We have continued to make strategic edits to these training requirements, such as reducing the audit frequency to semiannual from quarterly but maintain that a robust training and auditing program is necessary to ensure operators are able to see leaks that are present.

Comment: One commenter (2483) requested that EPA continue to adopt the revised draft protocol submitted by the Appendix K workgroup and continue to engage with the workgroup. The commenter asserted that the workgroup members, which include a diverse team of experts who have previously supported OGI research, development, and demonstration, are able to provide recommendations that would ensure that OGI and other remote sensing technologies remain viable.

Response II-22-53: Throughout the development of Appendix K, EPA has continued to engage with stakeholders. Prior to proposing Appendix K, EPA held an OGI workshop that was open to the public. Input from that workshop was used to develop the version of Appendix K that was included in the November 2021 Proposal. Based on input received during the comment period from various stakeholders, we revised Appendix K in the December 2022 Supplemental Proposal. We have made further revisions in the final version of Appendix K based on the comments we received from stakeholder on the December 2022 Supplemental Proposal.

Comment: Several commenters (2196, 2248) asserted that EPA should remove specific sections of Appendix K. One commenter (2248) stated that EPA should remove section 5.0 of Appendix K; the commenter stated that the requirements are not appropriate to include in the protocol, noting that safety conditions are extensively regulated by other agencies under robust regulatory frameworks, and additionally, each company has its own required and voluntary safety programs to address site-specific safety conditions.

Response II-22-54 EPA notes that Appendix K is formatted similarly to the test methods in parts 60, 61, and 63. These test methods generally contain a section on safety similar to the one in Appendix K. Section 5.0 of Appendix K is not meant to be all encompassing, and owners, operators and users of Appendix K should continue to adhere to other regulatory requirements on safety, as well as their own voluntary safety programs. Section 5.0 of Appendix K is only intended to make users generally aware of the types of hazardous they may encounter will using the protocol.

### ***22.9.2 Burden and Cost***

Comment: A couple of commenters (2366, 2483) expressed concern that the requirements of Appendix K remain too costly or burdensome and maintained that EPA failed to consider feedback on the initial proposal in the supplemental that would have streamlined some requirements that were burdensome. Commenters (2366, 2483) urged that although the

December 2022 Supplemental Proposal indicates that Appendix K only applies to the processing segment, the final version of the method will likely be adopted, or at least relied upon, by state agencies because it will be the only standalone method for OGI, and therefore could add unwarranted burden to operators in other segments.

One commenter (2366) suggested that EPA conduct a cost benefit analysis. Another commenter (2483) noted that EPA did not include the costs for Appendix K in its OOOOb and OOOOc analysis and should do so. The commenter stressed that if the burdensome criteria of Appendix K is used as precedent for other methods, implementation of new and developing technologies will be hindered.

Response II-22-55: EPA disagrees with the commenters. EPA made substantial changes between the November 2021 Proposal and December 2022 Supplemental Proposal that reduced the burden of implementing Appendix K. EPA has continued to streamline the requirements of Appendix K based on feedback received from commenters on the December 2022 Supplemental Proposal. EPA cannot stop delegated authorities from requiring the use of Appendix K on their own, but we have clearly stated that Appendix K only applies where a subpart references it.

EPA is not conducting a cost benefit analysis for Appendix K because on its own Appendix K does not apply to any sector. Each sector is different regarding the types and number of components that must be monitored, as well as the frequency of monitoring. Therefore, it isn't possible to do a one-size-fits-all type of cost benefit analysis for Appendix K. This is why cost benefit analyses are performed for individual subparts during rulemakings.

EPA notes that all technologies are different, and each technology will require analysis of necessary quality assurance requirements to ensure adequate implementation. Some technologies rely less on operator experience or involvement, and in that instance, training of operators is likely to either not be necessary or to be greatly reduced. EPA is committed to reviewing new technologies and creating pathways for their use.

Comment: One commenter (2220) expressed concern that the requirements of Appendix K remain too costly or burdensome and that the requirements would impose a massive workload and strain on both operators and state agencies. The commenter was concerned that state agencies would need to hire additional full-time employees and incur additional training, equipment, and other associated costs not considered in the proposal. The commenter estimated costs for initial training to certify staff in operating OGI cameras would initially be roughly \$80,000 to \$100,000, and the cost of purchasing and regularly maintaining necessary OGI equipment to comply with the requirements is estimated at \$1.3 million.

The commenter further noted there would be costs to operators to hire qualified third-party contractors to perform some of the OGI fugitive emissions monitoring, which may be infeasible for some smaller operators. The commenter stated that the requirements could result in potential adverse economic impacts, as the cost associated with monitoring surveys outlined in Appendix K would impose expenses on small operators that exceed their revenues. The commenter was also concerned that the requirements in Appendix K would require operators to dedicate more time and resources to performing OGI inspections, which could consume available resources that

would otherwise be dedicated to performing ongoing compliance duties, such as making repairs. Based on this information the commenter contended that the increased burden had no significant environmental outcome and surmised that contractor costs will escalate from current levels due to the increased demand.

Response II-22-56: Personnel in federal, state, and local government agencies performing oversight duties are not required to meet the requirements outlined in Appendix K. The rigor of Appendix K is intended to ensure that owners or operators (or their contractors) conducting leak surveys are properly trained and conduct surveys in a manner to minimize the incidence of not finding leaks that are present. The occurrence of false leaks with an OGI camera is a much less likely scenario and can easily be guarded against by a general understanding of interferences that can occur during an OGI survey. Therefore, the only issue that arises from agency personnel not being trained to the rigor of Appendix K is that the agency personnel may not find all of the leaks that are present at the site, although they should be able to find the largest leaks with a basic level of OGI training. As such, the requirements outlined in Appendix K should cause no burden for federal, state, and local government agencies.

EPA acknowledges that there are costs associated with implementing any leak detection program, whether leak detection monitoring is conducted with OGI or EPA Method 21. A cost analysis is conducted for each rulemaking where a leak detection program is implemented. EPA generally considers the cost of in-plant personnel and third-party contractors, as well as the frequency for conducting the monitoring. EPA notes that Appendix K is only required for OGI surveys at natural gas processing plants in NSPS OOOOb and EG OOOOc. Additionally, EPA has provided owners and operators the option to use EPA Method 21 for these sources if the owner or operator wishes to do so. As such, owners and operators can choose to implement the program that works best for their site.

EPA disagrees that Appendix K provides no significant environmental outcome or that it takes time away from performing other duties, such as repairs. Generally, OGI surveys, even surveys conducted using Appendix K, can be performed more quickly than a monitoring event with EPA Method 21, and as such, the owner or operator reduces the amount of time spent monitoring and has more time to conduct maintenance and repair. Additionally, because technique and training are paramount to an OGI camera operator finding leaks where they exist, the requirements outlined in Appendix K ensure that more leaks will be found, thereby reducing emissions to the environment and creating a positive environmental impact.

## **22.10 Incorporations by reference**

In some cases, commenters incorporated by reference all or part of a comment letter submitted by another commenter. Rather than repeat the associated comment excerpts for each commenter, the EPA has listed the comment excerpt only once and provided a list of all the commenters who otherwise incorporated the comments by reference in the table below.

**List of Comment Letters Incorporated By Reference from Docket No. EPA-HQ-OAR-2021-0317**

| <b>Commenter</b>          | <b>Commenter Affiliation</b>            | <b>Incorporations by reference</b>                      | <b>IBR'd DCN</b>          |
|---------------------------|-----------------------------------------|---------------------------------------------------------|---------------------------|
| EPA-HQ-OAR-2021-0317-2255 | Ovintiv Inc.                            | American Petroleum Institute (API)                      | EPA-HQ-OAR-2021-0317-2428 |
| EPA-HQ-OAR-2021-0317-2366 | Berkshire Hathaway Energy Company (BHE) | Interstate Natural Gas Association of America (INGAA)   | EPA-HQ-OAR-2021-0317-2483 |
| EPA-HQ-OAR-2021-0317-2399 | GPA Midstream Association               | GPA Midstream Association (from November 2021 Proposal) | EPA-HQ-OAR-2021-0317-0817 |
| EPA-HQ-OAR-2021-0317-2401 | State of Wyoming                        | Wyoming Department of Environmental Quality             | EPA-HQ-OAR-2021-0317-2220 |

## Chapter 23. Miscellaneous Other Comments

### 23.1 General Support-Opposition to Proposed Action

#### *23.1.1 General Support for the Rule and Reduction of Emissions from Oil and Natural Gas Sources*

Comment: Commenters (1611-ELPC, 1620-EEN, 1633-NRDC, 1642-PJSN, 1644-YECA, 1647-Physicians for Social Responsibility Pennsylvania, 1648- 1651-CJM, 1659-CRP-PA Chapter, 1900-Private Citizen, 2036-NPCA, 2152-CALSTRS, 2163-EOS Federated Hermes, 2164-NA Management, 2166-ODNR, 2209-PLS, 2212-UCS, 2242-SGI, 2244-NK, 2245-Private Citizen, 2248-NDPC, 2249-NACAA, 2256-MLBO, 2271-Private Citizen, 2293-SH, 2296-NMED, 2299-NEI Investments, 2302-Texas State Representatives, 2303-NTAA, 2329-Sierra Club LSC, 2356-Earthworks et al, 2364-CE4K, 2396-Shell, 2420-WHPCA, 2422-WLN, 2425-TCS, 2429-WOC, 2434-Private Citizen, 2441-HAWC, 2456-Private Citizen, 2499-Ohio Conservative Energy Forum, 2627-BCIMC, 2628-Private Citizen, 2697-STAM, 2766-1000 Grandmothers, 2883-Congress, 3001-Great Old Broads for Wilderness, 3083-Private Citizen, 3335-Private Citizen, 3389-Private Citizen, 3399-Private Citizen, 3486-Private Citizen, 3602-Fort Berthold Protectors of Water and Earth Rights, 3585-Vote Solar, 3621-Private Citizen, 3653-Private Citizen, 3660-Private Citizen, 3705-Breathe Easy Susquehanna County, 2796-Chicago Area Peace Action, 3507-Save the Sound, 3611-Private Citizen, 3733-350 Bay Area Action, 3775-Mothers and Others for Clean Air, 3794-Parents for a Safer Environment, Others) support EPA curbing methane, volatile organic compound (VOC), and hazardous air pollutant (HAP) emissions from the oil and gas sector in order to address climate change mitigation goals and environmental/ecological/public health. Commenters request that the EPA push for the strongest, most comprehensive methane rules possible to protect the peoples' health from all sources of oil and gas methane pollution, to slow down the degradation of our environment and minimize harm to future generations. Many of these commenters requested that EPA further strengthen requirements (e.g., ban or limit flaring, strengthen abandoned well requirements). Several commenters specifically note that they support the EPA's proposal to establish emissions guidelines (EG) for existing oil and natural gas infrastructure because regulating existing sources will drive the largest portion of emissions reduction.

Commenter (2249-NACAA) provides that the supplemental proposal expands the November 2021 proposal to address numerous additional sources through performance standards and guidelines. The commenter generally supports these expansions within the proposed rule, which would eliminate important loopholes and provide more complete and consistent protections. These technical considerations include the articulation of standards for liquids unloading operations, pneumatic pumps, and dry seal compressors.

Commenter (2396-Shell) supports the EPA's efforts to establish rigorous performance standards for reducing methane emissions from new and existing facilities within all segments of the oil and gas sector. Commenter (2256-Mille Lacs Band of Ojibwe) notes that within their air shed but not within their treaty-ceded territories is a liquified natural gas (LNG) storage facility that tempers the availability of natural gas in their local natural gas transmission network. By



eliminating any fugitive emissions from facilities such as this one, they note that it will also help further the U.S. climate change mitigation goals.

Several commenters (1651-CJM, 1655-AAP, 2036-NPCA, 2037-Climate Action CA, 2209-PLS, 2212-UCS, 2302-Texas State Representatives, 2313-Private Citizen, 2335-Private Citizen, 2441-HAWC, Others) specifically state that given methane's prodigious short-term climate forcing power and contribution to climate change, reducing methane emissions deserves the most prompt and aggressive approach possible.

Commenter (2185-NY CRF) asks EPA to require methane reductions that are consistent with pathways to achieve net zero greenhouse gas (GHG) emissions by mid-century, such as the International Energy Agency (IEA) Net Zero Emissions by 2050 Scenario, which requires methane emissions from fossil fuel operations to fall by around 75 percent between 2020 and 2030.<sup>1</sup>

Commenter (1648-PA Audubon) states that reducing methane emissions is the fastest, easiest, and cheapest thing we can do to immediately slow the pace of climate change. Additionally, they state that we need the strongest possible supplemental methane rule to protect the health of humans, our feathered bird friends, and all other living beings on our planet. The commenter urges the EPA to enact the strongest possible methane safeguards and quickly finalize them.

Commenter (2164-NA Management) notes that establishing comprehensive and durable federal methane regulations will set a baseline for performance across the industry, which will provide long-term regulatory certainty and help to mitigate climate and transition-related risks for investors. Commenter (2163-EOS Federated Hermes) states without cutting methane significantly and rapidly, staying under 1.5-degrees C will not be possible, and 2-degrees C is increasingly out of reach. They provide that a recent Intergovernmental Panel on Climate Change (IPCC) report<sup>2</sup> points to potentially catastrophically high economic and societal costs of unmitigated warming, identifies methane pollution as one of the key drivers of climate change and underscores the urgent need for protective action to reduce methane emissions significantly. This disruption would pose systemwide threats to company financial performance, investors, and their beneficiaries, including retirees from all walks of life.

Commenter (2462-Private Citizen) provides two examples that show the broad consensus on the need to reduce methane emissions.

- (1) International Monetary Fund analysts<sup>3</sup> write in 2022 “Methane Emissions Must Fall for World to Hit Temperature Targets”.
- (2) Thousands of climate scientists, e.g., Schaeffer (2019)<sup>4</sup>: “Earlier cuts [in methane] mitigate climate feedbacks and avoid climate tipping points. Methane mitigation is

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<sup>1</sup> <https://www.iea.org/reports/curtailing-methane-emissions-from-fossil-fuel-operations/executive-summary>.

<sup>2</sup> IPCC Sixth Assessment Report [<https://www.ipcc.ch/report/ar6/wg1/>].

<sup>3</sup> Black et al. 2022. <https://www.imf.org/en/Blogs/Articles/2022/11/02/methane-emissions-must-fall-for-world-to-hit-temperature-targets>.

<sup>4</sup> Schaeffer. 2019. On the Causes and Consequences of Recent Trends in Atmospheric Methane <https://doi.org/10.1007/s40641-019-00140-z>. Published online: 22 August 2019 Current Climate Change Reports (2019) 5:259–274.

therefore of higher importance for the Representative Concentration Pathways (RCPs) that target a lower global temperature increase, such as RCP-2.6. Even under the most optimistic scenarios for future political and economic developments, as exemplified by the Shared Socioeconomic Pathway 1 (SSP1), methane cuts have to be regulated through policies.”

Some commenters specifically point to the adverse effects of climate change as support for reducing methane emissions. Examples of some of the specific comments provided are included in the following paragraphs.

*Rising Temperatures.* Commenter (2392-Earthjustice et al) states research shows that rising temperatures will alter the chemical and physical interactions that contribute to air pollution such as particulate matter and ground-level ozone. Prolonged warm seasons are projected to increase the number of days with poor air quality, in part due to increased risk of wildfires and windblown dust events. The resulting increased exposure to air pollutants is likely to have “significant respiratory and cardiovascular health effects.”

Commenter (2392-Earthjustice et al) states rising global temperatures are projected to increase heat-related illnesses and deaths. Increased exposure to higher temperatures impacts the human body’s ability to regulate internal temperatures, and exacerbates pre-existing conditions, such as cerebral, respiratory, and cardiovascular diseases. The commenter notes that latine, low-income, and black populations are respectively 1%, 11%, and 41% more likely to live in areas with the highest projected increases in extreme-temperature related deaths. One broad study found that Black mothers are disproportionately exposed to the overlapping risks of extreme heat and air pollution, putting them at greater risk of adverse pregnancy outcomes.

Commenter (2392-Earthjustice et al) states climate-driven increases in the frequency and intensity of extreme heat is expected to impact labor sectors where employees work outside and where employees work inside but without access to air conditioning. Vulnerable weather-exposed industries include agriculture, forestry, fishing and hunting, mining, construction, manufacturing, and transportation and utilities. As temperatures rise to unsafe levels, workers in these industries may see their hours reduced or be unable to work at all.

*Extreme Weather Events.* Several commenters (2036-NPCA, 2215-WVRC et al, 2420-WHPCA, 2441-HAWC ) point to extreme weather events due to rising temperatures occurring at greater frequency, fueled by climate change, like record flooding and wildfires, longer and more intense allergy seasons, increased risk from water-borne and vector-borne diseases such as Lyme Disease, and worsening air quality.

Commenter (2441-HAWC) provides that wildfires have displaced communities and disrupted critical infrastructure. Wildfires have put additional pressure on public health and emergency response resources which have already been strained thin under the pandemic. Wildfires also contribute to particulate pollution and air pollution levels where it was unsafe to exercise or even walk outside.

Commenter (1648-PA Audubon) notes birds and amphibians are the most threatened by global warming and climate change. About 90 percent of some bird populations have already declined due to climate change. The National Audubon Society states that climate change is today's biggest threat to birds. Climate change has caused advanced spring migration, changes in birds' habitats, higher possibility of disease transmission, earlier egg-laying time, less food availability, and a decline in the bird population.

Other commenters provide comments on local air quality concerns. Commenter (2296-NMED) notes that several ozone monitors in New Mexico show that air quality is approaching or exceeding the 2015 ozone national ambient air quality standards (NAAQS). The commenter provides that the Sunland Park area in southern New Mexico is currently designated as in nonattainment of the 2015 ozone NAAQS, with an additional seven counties in the state monitoring ozone concentrations at or above 95 percent of the standard. Monitored ozone concentrations increased throughout New Mexico over the last several years, including both of New Mexico's oil and natural gas producing regions in the San Juan and Permian Basins. According to the EPA's latest National Emissions Inventory (NEI) (EPA, 2014 NEI version II), over 80 percent of the emissions in these areas are from oil and natural gas sources. The commenter adds that the Carlsbad ozone air monitor (AQS ID # 35-015-1005) in the Permian Basin, which is an area of rapid growth in oil production, serves as a prime example of the air pollution problems facing New Mexico. The design value for ozone at this monitor has elevated from 68 ppb in 2016 to 78 parts per billion (ppb) in 2020. The commenter states that the 2021 data show some of the highest monitored ozone concentrations recorded in the past decade, indicating this upward trend will continue throughout the state.

To improve air quality in these areas, the commenter (2296-NMED) reports that they developed the Ozone Attainment Initiative (OAI) and joined the EPA's Ozone Advance program. As part of the OAI, the commenter is currently researching options for control measures for all source sectors. The EPA's proposed rule is fundamental to reducing emissions from the oil and gas sector. Without these important reductions, according to the commenter, additional counties in New Mexico and other states may exceed the 2015 ozone NAAQS, resulting in additional nonattainment area designations and nonattainment permitting requirements. Recent photochemical modeling indicates that interstate transport contributes to high ozone concentrations in New Mexico. As a result, New Mexico faces nonattainment designations and increased nonattainment permitting requirements, while many states contributing to these exceedances have taken no action to address their contributions. According to the commenter, this further emphasizes the need for strong, federally enforceable emissions standards for the oil and natural gas sector to ensure fair and equitable requirements in basins that span state lines.

Response II-23-1: These comments are supportive comments; as such, no response is required. While these commenters generally support the development of the NSPS OOOOb and EG OOOOc rules, they urge EPA to do more to reduce methane and VOC emissions from the oil and natural gas industry. As discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior

EPA regulations or states' regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

Comment: Commenter (2147-Private Citizen), while supporting the rule, suggests that the evidence shows that lack of enforcement allows the oil and gas industry to keep emitting. <https://www.hcn.org/articles/energy-industry-new-mexicos-new-pollution-rules-leave-oil-and-gas-operators-to-police-themselves>. The commenter asserts that new methane rules without strong enforcement mechanisms are ineffectual. The commenter adds that self-reporting by the industry is also a big problem and provides the following on the issue: <https://www.hcn.org/articles/energy-industry-new-mexicos-new-pollution-rules-leave-oil-and-gas-operators-to-police-themselves>.

The commenter (2147-Private Citizen) explains that they believe that there is a disconnect between the rule-making process, the subsequent implementation and enforcement process, and the profound and immediate impacts of methane emissions. The commenter asserts that enforcement mechanisms for non-compliance must be swift and effective.

Response II-23-2: A similar comment regarding the need for enforcement was also provided on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.15 (Enforcement), Response I-23-64 for response to this comment.

### ***23.1.2 United States Responsibility to Reduce Emissions***

Comment: Commenters (1659-CRP, 2461-CRS, 2501-OS) state that given that the U.S. is one of the largest global emitters of methane, the U.S. has the opportunity and responsibility to devise effective strategies for a rapid and sustained reduction in methane emissions, to limit near-term warming, improve air quality, and help mitigate the worst outcomes of climate change.

Commenter (2163-EOS Federated Hermes) states the rule would progress the U.S. climate leadership at COP27 in Sharm El-Sheikh, Egypt including via the Joint Declaration from Energy Importers and Exporters<sup>5</sup>, Egypt, that builds on the commitment to push for methane reduction

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<sup>5</sup> Joint declaration from energy importers and exporters on reducing GHG emissions from fossil fuels [ <https://www.state.gov/joint-declaration-from-energy-importers-and-exporters-on-reducing-greenhouse-gas-emissions-from-fossil-fuels/> (note: link no longer works)].

through The Global Methane Pledge which would support the 1.5-degrees C goal in a collective effort to reduce global methane emissions at least 30 percent by 2030.<sup>6</sup>

Response II-23-3: See Response II-23-1 of this Chapter.

Comment: Commenter (2396-Shell) states one of the key regulatory elements is the establishment of rigorous performance standards that strive to achieve an ambitious methane intensity performance level for the upstream segments of the oil and gas supply chain. Although the exact numeric value would depend on a variety of factors, including the availability of accurate measurement data, the commenter believes that performance standard should most likely be in the range of 0.20 percent based on the benchmark set by the upstream industry under the Oil and Gas Climate Initiative (OGCI). The commenter provides that another key element of the methane regulatory program should be the establishment of robust monitoring, reporting, and verification (MRV) protocols aligned with the Oil and Gas Methane Partnership's Methane Emissions Reporting Framework 2.0 (OGMP 2.0) across the full natural gas value chain. A third and final element states by the commenter is the development of a flexible implementation framework that allows for the conversion of EPA's final methane performance standards set for each affected facility and emitting activity into an overall methane intensity standard for each of the upstream segments of oil and natural gas source category that are to be regulated by the EPA regulations.

Commenter (2396-Shell) is urging adoption of these three key elements to ensure proper alignment of the U.S. regulatory framework with methane regulatory programs of other countries, such as those in the European Union. The commenter contends that this alignment is necessary to demonstrate that the U.S. will meet its commitment to reduce methane emissions through the Global Methane Pledge that President Biden announced last November in COP26. In addition, they add that it will be critically important for demonstrating regulatory equivalence between methane regulatory programs in the U.S. and other countries to support and facilitate the efficient flow of liquid natural gas exports from the U.S. to the European Union and other countries.

Response II-23-4: A similar comment was provided by this commenter on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.11 (Other Recommendations for Reducing Impacts from Methane Emissions), Response I-23-58 for response to this comment.

### ***23.1.3 General Opposition to the Rule***

#### ***23.1.3.1 General Opposition to Rule as Proposed***

Comment: Commenter (2292-WV AG et al) states that reducing methane emissions is a noble goal that industry stakeholders have already been working toward. The oil sector, for instance, reduced methane missions relative to production by 60 percent between 2011 and 2020. See Tackling Methane Emissions, AM. PETROLEUM INST., <http://bit.ly/3l65lsP> (last visited Feb. 3, 2023). They add that other reduction efforts, like the Oil & Gas Methane Partnership 2.0 and

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<sup>6</sup> Global Methane Pledge [<https://www.ccacoalition.org/en/resources/global-methane-pledge>].

the Texas Methane & Flaring Coalition, are underway. However, the commenter contends that admirable environmental goals do not justify what they believe would be crushing to the American energy sector. They assert that top-down, heavy-handed governmental control is not the way to achieve the right balance between energy needs and environmental concerns—rather, they believe that American ingenuity and innovation, fostered by private initiative and state leadership should be the avenue to provide solutions. The commenter believes that the December 2022 supplemental proposal leaves little room for that. The commenter recommends that the agency abandon the proposal.

Commenter (2322-AR DEQ) states that the proposed rule creates a regulatory framework that conflicts with the current regulatory authorization enacted by the Clean Air Act (CAA) and corresponding Arkansas law. They note that, due to the complexity of this proposal, the unintended consequences for small businesses and families, the conflict of laws created by this proposal, and the significant changes to the original proposal presented by EPA in the December 2022 supplemental proposal, they urge EPA to withdraw the proposed rule. The commenter suggests that, if EPA moves forward, EPA reconsider what they believe are problematic and onerous requirements for states and oil and gas operators included in the proposed rule.

Commenters (2227-WEA, 2241-UDNR) encourage EPA to continue to evaluate the provisions discussed within the proposed rules, so that ultimately when the rules are published, it can fully allow for the intricacies and nuance required to effectively regulate industries as complex as the upstream and midstream oil and natural gas segments. The commenters contend that the EPA’s summary of potential rule provisions lacks flexibility and consideration for several factors that will make compliance impractical, if not technically infeasible, and in some cases may result in an overall increase in total GHG emissions.

Response II-23-5: In response to the claim that the proposals would be “crushing” to the American energy sector, the EPA disagrees. See responses to comments in Volume II, Chapter 20 (Impacts of the Proposed Rule), section 20.3.3 (Energy Impacts) for EPA’s response to other comments received that express concern over the impacts of the proposal on energy production and costs.

See also sections XVI.C (What are the cost impacts?) and D (What are the economic impacts?) of the final rule preamble where the EPA presents a summary of the results of the cost and economic impact and distributional analyses conducted.

The EPA disagrees with the request and basis provided by commenters for withdrawing/abandoning the NSPS OOOOb and EG OOOOc rules. The EPA considered, however, these and other comments when revising the NSPS OOOOb and EG OOOOc regulatory text proposed with the December 2022 Supplemental Proposal, including some of the nuances (*e.g.*, allowing for alternative standards) brought up and supported by the comments on the proposals. See section X of the final rule preamble for a summary of the final NSPS OOOOb and EG OOOOc requirements.

### 23.1.3.2 Do Not Support Application of a One-Size Fits All Approach

Comment: Commenter (2257-MOGA) does not support application of the EPA’s “one-size-fits-all” approach to all oil and gas-producing states. The approach proposed by the EPA does not allow for operational flexibility by producers to accommodate uncontrolled variabilities like difficult ambient weather and annual weather patterns. Specifically, the commenter states that the EPA’s approach will adversely affect states like Michigan and prevent small businesses from competing on an equal and level playing field in a free-market economy because of its geographic location. The commenter believes the EPA has not considered all operational, market and industry variables when developing the current proposed regulations. The EPA must re-evaluate and develop emission reduction regulations that are flexible, practical and allow equal and fair competition within the marketplace.

Commenter (2168-INOGA) states EPA has recognized that the regulations are complex and has taken some steps to simplify the regulations. The commenter supports the concept of simplifying the regulation, but also believes that a “one size fits all” approach is not appropriate either. The commenter has engaged with EPA multiple times in the past and will continue to advocate for our members to have EPA promulgate common sense and cost-effective regulations that cover their operations.

Response II-23-6: Please see discussion of state flexibilities and response to comments section XIII.C.2 of the final preamble.

With regards to the commenter not supporting the application of the EPA’s “one-size-fits-all” approach to all oil and gas-producing states, similar comments were received on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), section 23.17 (One-Size Fits All Approach) for EPA’s responses to those comments.

## **23.2 Environmental Justice Concerns**

### ***23.2.1 Climate Change and Air Quality Impacts on EJ Communities***

Comment: Commenters (1651-CJM, 1665-EEN, 2163-EOS at Federated Hermes, 2184-SRCA, 2215-WVRC et al, 2242-Seventh Generation Interfaith, 2250-NRPE et al, 2271-Private Citizen, 2278-Springfield NAACP, 2287-ICCR, 2289-Galilee Baptists, 2325-Aclima, 2334-Liveable Arlington, 2352-Environment Texas, 2364-CleanEarth4Kids, 2394-Earthworks, 2420-WHPCA, 2422-WLN, 2424-AYS, 2429-WOC, 2441-HAWC, 2461-CRS, 2462-Private Citizen, 2466-Private Citizen, 2627-BC Investment Management, 2766-1000 Grandmothers, Others) express concern that methane is a primary driver of climate change that has impacts on communities of color and the most vulnerable, including children and pregnant mothers. Several of the commenters generally agree that due to its high effect and relatively low atmospheric lifespan, it is imperative that the EPA address methane pollution by putting in place a robust methane pollution standard for new and existing oil and gas operations. The commenters generally assert that a strong standard can help protect communities, especially communities of color and tribal communities, which disproportionately suffer from the effects of climate change and air pollution (e.g., ozone pollution).

Commenter (2184-SRCA) asserts that there is a direct line between rapid climate change and environmental injustice. The commenter argues that infrastructure impacts places of historic discrimination (formerly enslaved, Indigenous, Appalachian descendants living where their ancestors created communities under harsh discrimination). The commenter notes that these populations have low carbon footprints, but the highest proportion of environmental health hazards. The commenter suggests that, if wealthy, privileged communities had been equally targeted to lose their lands under eminent domain seizures or having polluters build in their neighborhoods — the U.S. would be on a par with countries approaching 100 percent renewable energy.

Commenters (1651-CJM, 2250-NRPE et al, 2278-Springfield NAACP, 2289-Galilee Baptists, 2334-Liveable Arlington) express that EPA’s December 2022 supplemental rule standards to regulate methane pollution from the oil and natural gas sector, the largest industrial source of methane, is a welcome improvement but they do not believe that the rule goes far enough. Commenter (2278-Springfield NAACP) states this is especially true for black communities impacted by climate change and air pollution.

Response II-23-7: While these commenters generally support the development of the NSPS OOOOb and EG OOOOc rules, they urge EPA to do more to reduce methane and VOC emissions from the oil and natural gas industry to reduce impacts on vulnerable communities. As discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior EPA regulations or states’ regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States’ largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,” issued on January 20, 2021.

See also section XVI.F (What analyses of environmental justice did we conduct ?) of the final rule preamble for a summary of the environmental justice analyses we conducted in support of the final rules, including environmental justice and the impacts of climate change, impacts of climate change on indigenous communities, and environmental justice impacts of ozone exposure due to oil and natural gas VOC impacts.

Comment: Several commenters (1665-EEN, 2392-Earthjustice et al) indicate that research shows that living in close proximity—i.e., within one mile or less—of an oil and gas facility increases



health risks associated with oil and gas pollution, like cardiovascular disease, respiratory disease, and cancer, increase with proximity to these facilities. Commenter (2441-HAWC) notes one study by the Colorado Department of Public Health and Environment found that those living within 500 feet of a wellsite were at greater risk of cancer and those living within 2000 feet of a wellsite were at greater risk for adverse health impacts. Commenter (2394-Earthworks) reports that a half mile “threat radius” distance from an oil and gas facility is a very conservative estimate of the area within which elevated levels of toxic pollution are seen, and the distance within which adverse health impacts have most clearly been correlated with the presence of oil and gas facilities. Commenter (2364-CleanEarth4Kids.org) asserts that the EPA must take action to protect all Americans and especially the 17.6 million people who live within 1 mile of at least one active oil/gas well.

Commenter (2236-PSR-Pennsylvania) stresses that the harmful effects fracking has on the public health of our communities are detrimental. They assert that it is essential to place emphasis on those living nearby oil and gas operations— where methane emissions can increase risk of heart disease, lung disease, asthma, infertility for men and women, cancers (such as acute lymphatic leukemia and ewing sarcoma), eczema, and reduced life longevity in comparison to those that do not live within a close proximity to an oil and gas site.<sup>7</sup>

Several comments were received specifically highlighting regional concerns. A summary of some of those concerns are provided in the following bullets:

- Commenter (2422-WLN) states that poor air quality and environmental degradation on and near tribal lands in the San Juan Basin of New Mexico and Colorado and across the U.S. West contributes to public health crises.
- Commenter (2236-PSR) states almost 1.5 million Pennsylvanians live or work within a half mile of an active oil or gas well and are being denied this right. These individuals and their communities are exposed to methane emissions from fracking which has a significant impact on their health.
- Commenter (2466-Private Citizen) notes that she has spoken to dozens of Pennsylvania families and property owners who have had their quality of life, their property, their health, and their drinking water ruined by the Marcellus shale industry. Last year, she reports that the Public Herald, an online investigative journalism site, uncovered that since 2004, Pennsylvania residents have complained to the Pennsylvania Department of Environmental Protection (DEP) over 10,000 times about water, health issues, and other harms caused by the oil and gas industry.
- Commenter (2392-Earthjustice et al) states it is well documented that dangerous air emissions from oil and gas operations harm the health of people living and working near oil and gas production areas.<sup>8</sup> In large oil and gas production states, significant numbers of residents are heavily impacted by these health harms. For instance, 5 million people in

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<sup>7</sup> Compendium published by PSR and Concerned Health Professionals of New York with Scientific, Medical, and Media Findings Demonstrating Risks and Harms of oil and gas drilling.

<sup>8</sup> Id. at 7, 9 (citing Lisa McKenzie et al., Ambient Nonmethane Hydrocarbon Levels Along Colorado’s Northern Front Range: Acute and Chronic Health Risks, 52 Env’t Sci. & Tech. 4414, 4414 (2018), <https://pubmed.ncbi.nlm.nih.gov/29584423/>[hereinafter “McKenzie et al., Nonmethane Hydrocarbon Levels Along the Front Range”]).

Texas, 3 million people in Ohio, 1.9 million people in Pennsylvania, and nearly a half-million people in Colorado live within just one mile of an oil or gas well.<sup>9</sup>

- Commenter (2394-Earthworks) adds the Oil and Gas Threat Map<sup>10</sup> shows 17.2 million people living within a half mile radius of oil and gas extraction, processing, or compressor stations. That includes 3.1 million at-risk students in more than 12,000 schools suffering 750,000 asthma attacks and 500,000 lost school days per year. This is an increase of 4.7 million people at risk since the last time the commenter updated their analysis in 2017.
- Commenter (1665-EEN) adds of the 3.1 million American children attending school within 0.5 radius of oil/gas facilities, Pennsylvania has at least 310,896 kids facing this hazard.<sup>11</sup> This makes addressing fugitive and leaking methane from both existing and leaking oil/gas facilities a moral responsibility.
- Commenter (2334-Liveable Arlington) states Arlington is a city of about 400,000 people in an area of 99 square miles on top of the Barnett shale. They have close to 400 methane gas wells using hydraulic fracturing in 52 drill sites, and the numbers are growing rapidly. The standard setback of 300 feet is measured from the wellhead to the main building of the protected use. That translates to gas wells right next door to daycares, homes, medical offices.
- Commenter (2334-Liveable Arlington) states 5.3 million Texans live within half a mile of an oil and gas site (the threat radius). In Tarrant County where their organization is based, close to 1 million out of 2.1 million residents live less than half a mile from fracking sites — the largest number of any county in America.
- Commenter (2334-Liveable Arlington) adds in EPA Region 6, almost 9 million people live within the threat radius of oil and gas development — more than half of the 17.3 million similarly impacted nationwide.
- Commenter (2501-Orion Strategies) reports that West Virginia is one of the top energy-producing states. West Virginia is home to many low-producing well sites that go unchecked and across our beautiful state, more than 50% of West Virginians live close to a well site. They note that the adoption of the proposed rule would ensure that all well sites, including high-polluting and low-producing wells, are properly monitored for emissions. As such, West Virginia is in drastic need of commonsense inspection standards for oil and gas wells to protect our communities.
- Commenter (2215-WVRC et al) asserts that Appalachians and West Virginians are especially at risk due to the many active and abandoned oil and gas wells in the region. Over half of West Virginians live within a mile of an active oil and gas well, and there are approximately 6,500 abandoned and orphaned wells in the state leaking methane. Low-producing oil and gas wells are responsible for half of all well-site methane pollution in the country, and Appalachia has the highest quantity of these sites nationwide with over 180,000 wells. The most populated county in West Virginia, Kanawha County, has 3,303 of these polluting wells – the highest number of low-producing wells in a single county. It is clear that pollution from the oil and gas sector is a pressing issue in

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<sup>9</sup> Jeremy Proville et al., The Demographic Characteristics of Populations Living Near Oil and Gas Wells in the USA, 44 *Population and Env't* 1, 10 (2022), <https://link.springer.com/article/10.1007/s11111-022-00403-2> [hereinafter “Proville et al, Demographics Near Oil and Gas Wells”].

<sup>10</sup> The Oil and Gas Threat Map, <https://oilandgasthreatmap.com/>.

<sup>11</sup> <https://oilandgasthreatmap.com/>.

West Virginia, and the supplemental proposal to reduce this harmful pollution represents much-needed action to alleviate the burden felt by West Virginians from extractive industry.

- Commenter (2215-WVRC et al) states the high concentration of active and abandoned oil and gas wells in West Virginia exacerbates the public health crisis that already exists in West Virginia. West Virginia ranks highest in the nation for prevalence of heart attack and coronary heart disease, has the second highest cancer mortality rate, and is among the worst ranked for chronic respiratory disease. As one of the oldest populations in the nation, West Virginians are particularly vulnerable to negative health outcomes from these pollutants.

Response II-23-8: See Response II-23-7 of this Chapter.

### ***23.2.2 Water Quality***

Comment: Commenter (2392-Earthjustice et al) states although the December 2022 supplemental proposal does not cover water quality, a robust environmental justice analysis must address cumulative impacts incorporating cross-media effects on disproportionately impacted communities. In the context of oil and gas infrastructure and pollution, a discussion of associated water quality impacts provides crucial context for understanding cumulative impacts, including in addition to the adverse air quality impacts discussed above. The commenters note that EPA did not consider water quality impacts of oil and gas development in its Regulatory Impacts Analysis (RIA), but they consider this analysis informative for the purpose of analyzing disparate impacts associated with oil and gas infrastructure and pollution.

Commenter (2392-Earthjustice et al) continues, the extraction of oil and gas has been linked with adverse impacts on water quality. Ample evidence connects fracking with groundwater contamination.<sup>12</sup> Fracking also negatively impacts surface waters. The commenter notes that a recent study identified a correlation between newly drilled wells and salt concentrations in surface waters and noted that concentrations were highest in the aftermath of hydraulically fracturing an oil formation.<sup>13</sup> Because salt compounds are commonly found in water coming from newly fracked wells, these findings raise concerns that more dangerous substances, such as toxic chemicals used in oil and gas extraction, could also be reaching surface waters. The commenter adds that the EPA has also identified evidence that the discharge of inadequately treated fracking wastewater has contaminated surface and drinking water resources.<sup>14</sup> Outside of

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<sup>12</sup> Gayathri Vaidyanathan, Fracking Can Contaminate Drinking Water, Sci. Am. (Apr. 4, 2016), <https://www.scientificamerican.com/article/fracking-can-contaminate-drinking-water>; Dominic C. DiGiulio and Robert B. Jackson, Impact to Underground Sources of Drinking Water and Domestic Wells from Production Well Stimulation and Completion Practices in the Pavillion, Wyoming, Field, 50 Env't Sci. & Tech. 4524, 4524-36 (2016), <https://pubs.acs.org/doi/abs/10.1021/acs.est.5b04970>.

<sup>13</sup> Pietro Bonetti et al., Large-Sample Evidence on the Impact of Unconventional Oil and Gas Development on Surface Waters, 373 Sci. 896, 896 (2021), <https://pubmed.ncbi.nlm.nih.gov/34413233/>.

<sup>14</sup> U.S. Env't Prot. Agency, Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States: Executive Summary at 1-2 (2016), <https://cfpub.epa.gov/ncea/hfstudy/recordisplay.cfm?deid=332990>.

the context of fracking, the commenter reports that stormwater runoff from oil and gas well pads has been found to introduce contaminants into nearby surface waters.<sup>15</sup>

Commenter (2392-Earthjustice et al) argues the disparate impacts of water quality degradation resulting from oil and gas extraction are acutely experienced by Black, Latine, tribal, and rural and low-income communities. In south Texas, the commenter states that researchers found evidence that areas with more than 80 percent population of color were twice as likely to live near fracking wastewater disposal wells than areas with less than 20 percent population of color.<sup>16</sup> Of the 217,624 people of color living less than three miles from a disposal well in southern Texas, 83.3 percent were Latine and 13.8 percent were Black.<sup>17</sup> A separate study analyzing the siting of fracking wells in the Marcellus shale region of Pennsylvania found evidence for income disparities in well siting.<sup>18</sup> The commenter adds that tribal communities have also faced unique threats to water quality from oil and gas infrastructure. For example, the Dakota Access Pipeline, which transports oil extracted from the Bakken oil fields in North Dakota, threatens water quality, and disturbs sacred sites of the Standing Rock Sioux tribe.<sup>19</sup>

Response II-23-9: With regards to comment that, “although the December 2022 supplemental proposal does not cover water quality, a robust environmental justice analysis must address cumulative impacts incorporating cross-media effects on disproportionately impacted communities”, the commenter is correct that water quality does not fall under the scope of the final rulemaking.

See also section XVI.F (What analyses of environmental justice did we conduct ?) of the final rule preamble for a summary of the environmental justice analyses we conducted in support of the final rules, including environmental justice and the impacts of climate change, impacts of climate change on indigenous communities, and environmental justice impacts of ozone exposure due to oil and natural gas VOC impacts.

### ***23.2.3 Vulnerable Communities***

Comment: Below are specific comments received on vulnerable communities affected by oil and natural gas infrastructure and the air quality and climate change effects of emissions of methane, criteria pollutants (e.g., VOC, NOx), and HAP.

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<sup>15</sup> Khadeeja Abdullah et al., Regulating Oil and Gas Facility Stormwater Discharge: An Assessment of Surface Impoundments, Spills, and Permit Compliance, 76 Env’t Sci. & Pol’y 139, 139 (2017), <https://www.sciencedirect.com/science/article/abs/pii/S1462901116308206>.

<sup>16</sup> Jill Johnston et al., Wastewater Disposal Wells, Fracking, and Environmental Justice in Southern Texas, 106 Am. J. Pub. Health 550, 554 (2016), <https://ajph.aphapublications.org/doi/pdf/10.2105/AJPH.2015.303000>.

<sup>17</sup> Id. at 553.

<sup>18</sup> Yelena Ogneva-Himmelberger & Liyao Huang, Spatial Distribution of Unconventional Gas Wells and Human Populations in the Marcellus Shale in the United States: Vulnerability Analysis, 60 Applied Geography 165, 165 (2015), <https://www.ejnet.org/ej/frackingthepoor.pdf>.

<sup>19</sup> Alleen Brown, Five Spills, Six Months in Operation: Dakota Access Track Record Highlights Unavoidable Reality – Pipelines Leak, The Intercept (Jan. 9, 2018, 1:39 PM), <https://theintercept.com/2018/01/09/dakota-access-pipeline-leak-energy-transfer-partners>; Chelsey Luger, DAPL Desecrated Sacred Sites, Took 10 Days to Tell State, as Human Rights Abuses Continue, Indian Country Today (Sept. 13, 2018), <https://ictnews.org/archive/dapl-desecrated-sacred-sites-took-10-days-to-tell-state-as-human-rights-abuses-continue>.

*Black, Latine, Native American and Low-Income Populations.* Commenters (2392-Earthjustice et al, 2420-WHPCA) note disparate air quality health impacts result from the siting of oil and gas operations and infrastructure. Disproportionately large numbers of people living near oil and gas wells across the U.S. are from low-income communities and communities of color.<sup>20</sup> Commenter (2392-Earthjustice et al) goes further, of the nearly 18 million people in the U.S. that live within one mile of an active oil or gas well, 3.3 million are Latine, 3 million live below the poverty line, 1.8 million are black, and 500,000 are Native American.<sup>21</sup> Research additionally shows that populations of color, and in particular black populations, are disproportionately more likely than other demographics to live near fracking wells.<sup>22</sup> The cumulative impacts associated with well siting are also acutely experienced in Latine and black communities, as baseline air quality is, on average, more polluted in these communities. A 2014 study found that majority Hispanic neighborhoods were exposed to greater and more dangerous concentrations of nitrogen oxides (NOx) and particulate matter than majority white neighborhoods in the same cities.<sup>23</sup> Likewise, Black communities are exposed to 1.54 times the amount of particulate matter than the overall population.<sup>24</sup>

Commenter (2392-Earthjustice et al) also notes that multiple studies show that Latine and low-income populations are disproportionately vulnerable to climate-related air quality health impacts. With 2°C of warming, the commenter reports that an EPA study found that Latine and low-income populations are respectively 10 percent and 15 percent more likely than others to live in areas projected to have the highest climate-driven increases in childhood asthma.<sup>25</sup> Similarly, a 2021 of the Denver Metro-North Front Range ozone nonattainment area found that, when accounting for the effect of climate change on ozone trends, ozone levels are expected to increase the most in urban majority Latine and low-income communities.<sup>26</sup>

Commenter (2392-Earthjustice et al) adds that black, Latine, tribal, and rural and low-income communities are also disparately vulnerable to the adverse economic impacts of weather-exposed labor markets. Assuming 2°C of warming, Latine populations are 43% more likely than non-Latine populations to live in areas with the highest projected labor hour losses in weather-exposed industries. Low-income populations, American Indian and Native Alaska, and Black

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<sup>20</sup> Proville et al., *Demographics Near Oil and Gas Wells*, supra n.30, at 1; Jeremy Proville et al., *County & State Level Data (2022)* (providing breakdowns of data assessed in Proville et al., *Demographics Near Oil and Gas Wells*, supra n.30),

<https://www.dropbox.com/s/gzas7gl2rj3ai17/County%20%26%20State%20Level%20Data.xlsx?dl=0>.

<sup>21</sup> Proville et al, *Demographics Near Oil and Gas Wells*, supra n.30, at 1.

<sup>22</sup> Concerned Health Pros. of NY & Physicians for Soc. Resp., *Compendium of Scientific, Medical, and Media Findings Demonstrating Risks and Harms of Fracking (Unconventional Gas and Oil Extraction)* at 52-53 (7th ed. 2020), <https://psr.org/wp-content/uploads/2020/12/fracking-science-compendium-7.pdf>.

<sup>23</sup> Miranda Jones et. al, *Race/Ethnicity, Residential Segregation, and Exposure to Ambient Air Pollution: The Multi-Ethnic Study of Atherosclerosis (MESA)*, 104 Am. J. Pub. Health 2130, 2130 (2014), <https://pubmed.ncbi.nlm.nih.gov/25211756/>.

<sup>24</sup> Ihab Mikati & Adam Benson, *Disparities in Distribution of Particulate Matter Emission Sources by Race and Poverty Status*, 108 Am. J. Pub. Health 480, 480-85 (2018), <https://pubmed.ncbi.nlm.nih.gov/29470121/>.

<sup>25</sup> Id. at 25.

<sup>26</sup> James L. Cooke, et al., *The Ozone Climate Penalty, NAAQS Attainment, and Health Equity Along the Colorado Front Range*, 32 J. Exposure Sci. & Env't Epidemiology 545, 551-52 (2021), <https://pubmed.ncbi.nlm.nih.gov/34504294/>.

communities are respectively 25 percent, 37 percent, and 23 percent more likely to live in these weather-impacted areas.

Commenter (2334-Liveable Arlington) states the health and economic costs of fracking is disproportionately borne by communities of color. In their very diverse community, they assert that fracking is an environmental justice issue.

Commenter (2364-CleanEarth4Kids.org) adds this is a racial, social, climate and environmental justice issue as urban fossil fuel drilling takes place in predominantly low-income communities of color.<sup>27</sup> The commenter reports that air pollution can trigger asthma attacks and black children have a 500 percent higher death rate from asthma compared with white children.<sup>28</sup> They note that there is a social cost of fossil fuels, a price that is being paid by low-income and people of color.

Commenter (2289-Galilee Baptist Church) notes that over one million African Americans live in counties that face a cancer risk above the EPA's level of concern from toxics emitted by natural gas facilities.

Commenters (2278-Springfield NAACP, 2289-Galilee Baptists) inform that more than 1 million people of African descent live within a half-mile of an existing natural gas facility, leaving these communities exposed to the toxic air pollution from methane gas. Commenters (2278-Springfield NAACP, 2289-Galilee Baptists, 2325-Aclima) state that the result of this exposure is increased cancer, reproductive and respiratory problems. Commenter (2289-Galilee Baptists) reports that illnesses contribute to missed work and school days. They note that methane pollution also contributes to climate change, which hits black communities first and worst in the form of flooding, heat waves and severe weather. The commenter provides that the African American community is disproportionately impacted because of historical and ongoing systemic racism, which has placed the commenters' communities adjacent to polluting industries.

Commenters (2303-NTAA, 2697-STA) state the emissions from oil and natural gas sources not only contribute to climate impacts, but seriously burden the health of nearby tribal communities. Ozone-forming VOCs and HAPs like benzene are emitted alongside methane. Inhalation of these dangerous pollutants can lead to irreversible lung damage, asthma attacks, and cancer, and Tribal communities already suffer from these illnesses at disproportionate rates. In this rulemaking, the commenter urges EPA to look at the environmental justice implications of the proposed action and seek to advance equity for all.

Commenter (2422-WLN) states that poor air quality caused by oil and gas pollution disproportionately impacts tribal communities. Environmental degradation on and near tribal lands in the San Juan Basin of New Mexico and Colorado and across the U.S. West contributes to public health crises.

Commenter (2353-CrownQuest) notes that the EPA points out the disproportionate benefit expected by these rules to indigenous peoples but also admits this rule will not apply to tribes in the U.S. as that is outside their authority bounds. According to the commenter, this rule is not a

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<sup>27</sup> <https://www.fractracker.org/2020/12/people-and-production/>.

<sup>28</sup> <https://www.epa.gov/children/childrens-environmental-health-facts>.

serious attempt to help any American. Otherwise, they believe that tribes would already be instituting these and other regulations on oil and gas activity on their lands.

*Children.* Commenter (1665-Evangelical Environmental Network) notes studies have shown that smog, VOCs, and air toxics have a disproportionate impact upon life in the womb. The commenter provides that research by Dr. Shaina L. Stacy and others at the University of Pittsburgh found close proximity to unconventional gas wells in Butler County, PA is associated with babies born with lower birthweight.<sup>29</sup> Dr. Lisa M. McKenzie with the Colorado School of Public Health published peer reviewed research that links birth defects to methane production.<sup>30</sup> They add that research by Casey J.A., et al (2019) further describes that living within a half-mile radius of natural gas development leads to increased brain, spine, or spinal cord birth defects.<sup>31</sup>

Commenter (2253-Our Children's Trust) asserts that giving equal protection to children under law means treating them differently than adults. They explain that children are unique physiologically, emotionally, behaviorally, and generationally, including their average life longevity as compared to adults, and due to their lack of political and economic power and their dependency on adults.

Commenter (2253-Our Children's Trust) notes that EPA has highlighted children's heightened likelihood of suffering climate change-induced harms. For example, "[c]hildren's bodies are developing physically, which can make them more vulnerable to climate-related hazards like heat and poor air quality. They also breathe at a faster rate, increasing their exposure to dangerous air pollutants"<sup>32</sup> In addition, they add that the EPA has broadly recognized both the particular vulnerability of children to environmental harm and the importance of incorporating their interests and protection into its policy:

Childhood is a life stage experienced by everyone, and exposure to contaminants during early life is a key consideration in the assessment of how environmental impacts shape human health over the course of a lifetime.

Commenter (2253-Our Children's Trust) adds children also have unique behaviors such as breast feeding, crawling and hand-to-mouth activity that may contribute to increased exposure. Children eat more food, drink more water, and breathe more air in proportion to their body size as compared to adults, and the variety of the foods they consume is more limited. As children are still growing and developing, they do not respond to toxic substances in the same way as adults.

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<sup>29</sup> Stacy SL, Brink LL, Larkin JC, Sadovsky Y, Goldstein BD, Pitt BR, et al. (2015) Perinatal Outcomes and Unconventional Natural Gas Operations in Southwest Pennsylvania. PLoS ONE 10(6): e0126425. doi: 10.1371/journal.pone.0126425, downloaded September 28, 2015, <http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0126425>.

<sup>30</sup> Lisa M. McKenzie, Ruixin Guo, Roxana Z. Witter, David A. Savitz, Lee S. Newman, and John L. Adgate, Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado, *Environmental Health Perspectives* doi:10.1289/ehp.1306722. downloaded September 28, 2015, <http://ehp.niehs.nih.gov/1306722/#tab3>.

<sup>31</sup> Casey J.A., et al., "The association between natural gas well activity and specific congenital anomalies in Oklahoma, 1997-2009," *Environment International*, Volume 122, January 2019, 381-388, <https://www.sciencedirect.com/science/article/pii/S0160412018317999?via=ihub>.

<sup>32</sup> Climate Change and Children's Health, <https://www.epa.gov/climateimpacts/climate-change-and-childrens-health> (last visited Feb 1, 2023).

For instance, they explain that their blood-brain barrier and metabolic processes are less mature. The timing of exposure to chemicals and other contaminants is critical in protecting human health. They note that the same dose of a chemical during different periods of development can have very different consequences.

Commenter (2253-Our Children's Trust) stresses that children who live in highly exposed or underserved communities may have reduced biological resilience and ability to recover from exposure to environmental hazards. With new threats and worsening conditions resulting from climate change, the EPA has a greater responsibility to provide children with heightened focus, assessment, and safeguards to protect their health.”<sup>33</sup>

Commenter (2253-Our Children's Trust) adds that climate change is causing a public health emergency that is already adversely impacting the physical and mental health of American children through, among other impacts, extreme weather events, rising temperatures and increased heat exposure, decreased air quality, altered infectious disease patterns, and food and water insecurity.<sup>34</sup> They provide that children are uniquely vulnerable to climate change impacts because of their developing bodies, higher exposure to air, food, and water per unit body weight, unique behavior patterns, dependence on caregivers, political powerlessness, and longevity on the planet.<sup>35</sup> The protection of constitutional rights of children, by following the science, is of the utmost importance and must be incorporated in all relevant EPA rulemaking and policies.

Commenter (2253-Our Children's Trust) states that they represent twenty-one youth plaintiffs, including eleven Black, Brown, and Indigenous youth, in the constitutional climate lawsuit, *Juliana v. United States*, in which the Administrator, in his official capacity, and EPA are defendants. This case asserts that, through the government's past and ongoing affirmative actions that cause climate change, it has violated the youngest generation's constitutional rights to life, liberty, property, and equal protection of the law, as well as failed to protect essential public trust resources. In this litigation, federal courts have affirmed “that the federal government has long promoted fossil fuel use despite knowing that it can cause catastrophic climate change”<sup>36</sup> and “has long understood the risks of fossil fuel use and increasing carbon dioxide emissions”.<sup>37</sup> The Ninth Circuit Court of Appeals found that there was evidence showing that the federal government was a substantial factor in causing the youth's constitutional injuries because “[a] significant portion of [GHG] emissions occur in this country; the United States accounted for over 25% of worldwide emissions from 1850 to 2012, and currently accounts for about 15 [percent].”<sup>38</sup> According to the commenter, without immediate effective action, our children and

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<sup>33</sup> Env'tl. Protect. Agency, 2021 Policy on Children's Health (Oct. 5, 2021).

<https://www.epa.gov/system/files/documents/2021-10/2021-policy-on-childrens-health.pdf>.

<sup>34</sup> IPCC, Summary for Policymakers, in *Climate Change 2022: Impacts, Adaptation and Vulnerability*, at 11, 17 (2022). This summary found that the current level of global warming is already driving heat waves that cause human morbidity, heavy rains, flooding, extreme fires and drought, coral bleaching and demise, massive shifts in species habitats, loss of glaciers, snow, and permafrost, as well as more destructive hurricanes. *Id.* at 11.

<sup>35</sup> Samantha Ahdoot, Susan E. Pacheco & Council on Environmental Health, *Global Climate Change and Children's Health*, 136 *Pediatrics* e1468 (2015); Rebecca Pass Philipsborn & Kevin Chan, *Climate Change and Global Child Health*, 141 *Pediatrics* e20173774 (2018); Wim Thiery et al., *Intergenerational Inequities in Exposure to Climate Extremes*, 374 *Science* 158 (2021).

<sup>36</sup> *Juliana v. United States*, 947 F.3d 1159, 1164 (9th Cir. 2020).

<sup>37</sup> *Juliana v. United States*, 947 F.3d 1159, 1166 (9th Cir. 2020).

<sup>38</sup> *Juliana v. United States*, 947 F.3d 1159, 1169 (9th Cir. 2020).



future generations will continue to suffer injury with long-lasting and potentially irreversible consequences.<sup>39</sup> They assert that these judicially-recognized facts should guide EPA's policies and practices so they can identify, and alter, those policies that exacerbate American youth's existing climate change injuries.

Commenter (2253-Our Children's Trust) adds under the 5<sup>th</sup> Amendment to the U.S. Constitution, the government is restrained from engaging in conduct that infringes upon fundamental rights to life, liberty, and property, and equal protection of the law, all of which includes a climate system that sustains human life and liberty. Under the Public Trust Doctrine, embedded in our Constitution and other founding documents, and in the very sovereignty of our Nation, U.S. residents (both present and future, i.e., posterity) have a right to access and use crucial natural resources, like air and water. The U.S. government, and its executive agencies, have fiduciary duties as trustees to manage, protect, and prevent substantial impairment to our country's vital natural resources which the government holds in trust for present and future generations.<sup>40</sup>

Commenter (2335-Private Citizen) adds recent studies have revealed the danger of living near fracking sites, most likely because of exposure to the methane gas and other GHG emitted from these sites. The commenter notes that a recent Smithsonian Magazine article discussed a study published by Environmental Health Perspective that showed a greatly increased risk of acute lymphocytic leukemia (ALL) in children and infants who live near fracking wells. They add that children near the wells were twice as likely to develop ALL as in the general child population, and babies born to pregnant women living near the wells had nearly 3 times the incidence of ALL.<sup>41</sup>

Commenter (2334-Liveable Arlington) reports that Tarrant County, has the highest rate of childhood asthma in the state and in the country. They note that almost one in five children have asthma. It also has the highest rate of birth defects recorded since 2007 of similar counties in Texas. The commenter adds that the Dallas Fort Worth region has not met federal ground level ozone standards in 30 years. They state that Barnett shale emissions contribute greatly to that.

More than 30,000 Arlington children go to public school within half a mile of wells, according to an analysis by Reveal from The Center for Investigative Reporting and up to 7600 attend private daycares within that radius. Eighty-five percent of the public-school students are children of color, and more than two-thirds live in poverty. Altogether, more than half of Arlington's public schools and day care facilities are within a half-mile of

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<sup>39</sup> See Assessing "Dangerous Climate Change"; James Hansen et al., Ice Melt, Sea Level Rise and Superstorms: Evidence from Paleoclimate Data, Climate Modeling, and Modern Observations that 2°C Global Warming Could be Dangerous, 16 *Atmos. Chem. & Phys.* 3761 (2016); U.S. Global Change Research Program, Fourth National Climate Assessment, Vol. II (2018); David I. Armstrong McKay et al., Exceeding 1.5°C Global Warming Could Trigger Multiple Climate Tipping Points, 377 *Science* eabn7950 (2022); Nico Wunderling et al., Global Warming Overshoots Increase Risks of Climate Tipping Cascades in a Network Model, 13 *Nature Climate Change* 75 (2023). Note that many researchers use the temperature targets set during the Paris Accord as a point of reference, not as a sanctioning of those levels of average planetary heating. See above as to why a 1.5°C target (hotter than today) is not lawful.

<sup>40</sup> *Juliana v. United States*, 217 F. Supp. 3d 1224, 1254 (D. Or. 2016).

<sup>41</sup> Smithsonian Magazine, "Children Living Near Fracking Sites Have an Increased Risk for Leukemia, Study Says" by Will Sullivan, August 25, 2022.

active gas production. Eight-day care centers are within 600 feet, the standard setback in Arlington.

Another commenter (2334-Liveable Arlington) similarly reports that a study from Yale University published in *Environmental Health Perspectives*, shows that childhood leukemia risks can triple in children from ages 2-7 who are exposed in utero, or after birth, to fracking emissions from distances as far away as 6,500 feet. The note that, in Arlington the setback is a mere 600 feet. The commenter provides examples where setback waivers were granted reducing the distance even further:

- Ten percent of the population in a 1,320 feet radius around the Truman site is made up of children under 5, where they would face a significantly higher cancer risk. They add that the Kookan Educational Center is a mere 2,200 feet away.
- Total Energies drilled and fracked 7 wells next door to 2 Arlington daycares in 2020-21 where they exerted great pressure on the city and succeeded in diluting a proposal to marginally expand daycare setbacks. Their openly stated reason — they wanted to drill more gas wells 280 feet from yet another preschool playground. When the city instituted a new rule requiring the use of electric rigs when drilling next to protected uses, Total Energies ignored that rule and continued operations with an emitting diesel-powered rig. The commenter states that they went undetected until their group turned them in. The commenter notes that they were allowed to continue work after a shutdown of a few weeks, and no fines were levied.

Response II-23-10: See Response II-23-7 of this Chapter.

#### ***23.2.4 Enforcement and Community Support to Mitigate Harm***

Comment: Commenters (2250-NRPE et al, 2278-NAACP Springfield, 2289-Galilee Baptists) request that the rule include ways for communities to access data and technology so that they can protect their homes and workplaces from methane pollution.

Response II-23-11: The scope of the rulemaking includes the regulation of oil and natural gas emissions sources of methane. See also Response II-23-7 of this Chapter.

With regards to data, methane emissions information is reported under the GHGRP. The GHGRP requires reporting of GHG data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO<sub>2</sub> injection sites in the United States. Approximately 8,000 facilities are required to report their emissions annually, and the reported data are made available to the public in October of each year.

See also section X.C (Super Emitter Program) of the final rule preamble for a summary of the final standards for the Super Emitter Program. This program is designed to provide a transparent, reliable, and efficient mechanism by which the EPA will provide owners and operators with timely notifications of super-emitter emissions data collected by the EPA-certified third parties using the EPA-approved remote sensing technologies (e.g., satellites). Where such an event is attributable to a source regulated under CAA section 111 (NSPS OOOO, OOOOa, or OOOOb,

or a state or Federal plan implementing EG OOOOc), the responsible owner or operator will take action in accordance with the applicable regulation.

Comment: Commenter (2184-PSRCA) urges EPA to ensure the enforcement of all federal laws that address environmental justice when locating methane emitting facilities (fracked gas well drilling sites, compressor stations, and pipelines, gas power plants, and liquid natural gas (LNG) facilities; mega-landfills). Despite National Environmental Policy Act (NEPA), Department of Transportation (DOT), and Clean Air and Water Act provisions to protect these historically discriminated populations from further burdens of methane and other toxic air & water pollution, they assert that these sites continue to negatively impact environmental justice communities.

Response II-23-12: Similar comments regarding the need for enforcement of federal laws were also provided on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.15 (Enforcement), Response I-23-64, for response to this comment.

Comment: Commenter (2203-Ceres) recommends, considering the strong public health, environmental and climate interests served by this rulemaking, that any final rule and implementation strategy rely principally on ongoing and careful monitoring and rigorous enforcement, rather than voluntary compliance by the regulated entities.

Response II-23-13: See Response II-23-7 of this Chapter.

Comment: Commenter (2334-Liveable Arlington) states Arlington is going through another fracking boom in the Barnett shale. According to the commenter, French energy giant Total Energy and others plan to drill more than 100 new gas wells here, more than 20 in Arlington alone in the last 6 months. According to the commenter, they are doing it very callously, with horrific media reports of air pollution, sick neighbors, and in one recent instance an entire neighborhood being sprayed with “produced water.”

Commenter (2334-Liveable Arlington) continues that Arlington approved 6 new fracked methane gas wells at the Truman site behind closed doors without notifying residents or holding a public hearing because of a prior drilling permit. The site is surrounded by a large apartment complex, 2 mobile home communities, and many homes. It is located about 1,000 feet from the AISD Athletics Center and about 1,250 feet from the AISD Center for Visual and Performing Arts.

Commenter (2334-Liveable Arlington) adds according to EPA’s EJ Screening tool, in a 1,320-foot radius around the site, 83% of the residents are people of color, 54% do not have a high school diploma, 67% are low income, 46% are linguistically isolated, and 10% of the residents are children under 5.<sup>42</sup> According to our EPA EJ Screen analysis, the community around Truman is already:

- In the highest percentile for Air Toxics Cancer Risk (95-100<sup>th</sup> percentile).

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<sup>42</sup> See the table accompanying this letter.

- In the 80-90<sup>th</sup> percentile for the Air Toxics Respiratory Hazards Index.

The commenter (2334-Liveable Arlington) argues that the permitting of 6 new gas wells will compound all the existing pollution, health, and economic burdens this neighborhood already faces, making this an egregious case of environmental injustice. Since the initial permit was issued more than 10 years ago, they note that hundreds of peer reviewed published research studies have linked fracking to serious health impacts.

The commenter (2334-Liveable Arlington) adds that, in 2020, the city council denied Total Energy a permit to drill behind a preschool at the AC360 site where all the enrolled children are black and Latino because of environmental justice concerns. Total Energy reapplied last year and won a reversal of the NO vote after putting intense pressure on the city council to ignore city permitting rules. Soon after, the commenter reports that, while drill site workers were opening tank hatches at the site, preschool staff in the playground became ill. A Texas Commission of Environmental Quality (TCEQ) investigation found nothing, however, a week later staffers once again got sick during another operation. As the city was getting ready to approve more gas wells at the site, the commenter's group had to file an emergency lawsuit to get the permit denied.

Commenter (2334-Liveable Arlington) expresses concern that there is no air monitoring done by the TCEQ, the state agency charged with air quality permits and regulation, or by the city of Arlington. Releases, venting of methane and dangerous toxics go on unreported, next to large numbers of children. The commenter asks the EPA to refer to this Optical Gas Imaging (OGI) video of compressor station pollution at the DWG site in Arlington:

<https://www.youtube.com/watch?v=DQILTIDvmH4>. Despite years of citizen and watchdog complaints to TCEQ, the commenter complains that no improvements have occurred. The commenter notes that there is a high school across the street, and many other schools within a half mile of this site.

Response II-23-14: The EPA acknowledges the commenter's concerns. As discussed in section II.A (Purpose of the Regulatory Actions) of the final rule preamble, the final rulemaking takes a significant step forward in mitigating climate-destabilizing pollution and protecting human health by reducing GHG and VOC emissions from the oil and natural gas industry, specifically the Crude Oil and Natural Gas source category. These mitigations are based on proven, cost-effective technologies already required by prior EPA regulations or states' regulations or deployed by industry leaders to reduce this dangerous pollution. The final rules will also encourage the deployment of innovative technologies that currently exist to rapidly and cost-effectively detect and reduce methane pollution and promote further innovation that is already under way to find even more efficient and effective ways to mitigate this pollution. Because methane is the main component of natural gas, the rules also result in more saleable product. The oil and natural gas industry is the United States' largest industrial emitter of methane. Human emissions of methane, a potent GHG, are responsible for about one third of the warming due to well-mixed GHGs, the second most important human warming agent after carbon dioxide. The EPA is finalizing the actions described in the preamble to the final rule in accordance with its legal obligations and authorities following a review directed by EO 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," issued on January 20, 2021.

See also section XVI.F (What analyses of environmental justice did we conduct ?) of the final rule preamble for a summary of the environmental justice analyses we conducted in support of the final rules, including environmental justice and the impacts of climate change, impacts of climate change on indigenous communities, and environmental justice impacts of ozone exposure due to oil and natural gas VOC impacts.

See also Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.15 (Enforcement), Response I-23-64, for a response to comments provided on the November 2021 Proposal regarding the need for enforcement of federal laws.

## **23.3 Performance of Existing and Previous Emissions Mitigation Programs**

### ***23.3.1 Previous Oil and Natural Gas Sector Federal Rule Performance***

Comment: Commenter (2168-INOGA) inquires whether the prior rule makings have been successful at reducing emissions, as claimed during the development of the regulation? Further, they ask, if EPA's rules failed to meet the advertised expectations, why is this current rule being promulgated? The commenter believes that the EPA should be required to show the data from prior rule makings, illustrating the expected emissions reductions and the actual emissions reductions prior to promulgating more significant regulations on the oil and gas industry. The commenter asks whether the actual performance data justify the actions, or is the intent of this rulemaking to increase the compliance burdens (i.e., operating costs) on the oil and gas industry?

Response II-23-15: In response to the commenter who inquires whether prior rulemakings have been successful at reducing emissions, while the previous rulemakings have been successful at reducing emissions, greater emissions reductions of VOC and methane emissions are needed. As discussed in the final rule preamble, these final actions stem from the EPA's authority and obligation under CAA section 111 to directly regulate categories of new stationary sources that cause or contribute to endangerment from air pollution and to promulgate EG for states to follow in regulating existing sources (designated facilities) in the source category. See section II (Executive Summary), subsections A (Summary of the Major Provisions of this Regulatory Action) and B (Purpose of the Regulatory Actions), and section IV (Statutory Background and History) of the final rule preamble for support for the development of the NSPS OOOOb standards and EG OOOOc presumptive standards.

In response to the comment as to whether the intent of this rulemaking is to increase compliance burden on the industry, see responses to comments in Volume II, Chapter 20 (Impacts of the Proposed Rule), section 20.3.3 (Energy Impacts) for EPA's response to other comments received that express concern over the impacts of the proposal on energy production and costs. See also sections XVI.C (What are the cost impacts?) and D (What are the economic impacts?) of the final rule preamble where the EPA presents a summary of the results of the cost and economic impact and distributional analyses conducted.

### ***23.3.2 EPA Voluntary Programs***

Comment: Commenters (2308-NSWA, 2320-APGA) support EPA's voluntary, incentive-based program known as the Methane Challenge. The commenter provides that it's a partnership between EPA and oil and gas companies to bring greater transparency and accountability to methane emission reduction.

Commenter (2308-NSWA) also supports EPA's Natural Gas STAR program. Citing the EPA's website:

Natural Gas STAR Program provides a framework for Partner companies with U.S. oil and gas operations to implement methane reducing technologies and practices and document their voluntary emission reduction activities. By joining the Program, Partner companies commit to evaluate and implement cost-effective methane emission reduction opportunities and communicate and share that information across their corporation and with the Natural Gas STAR Program.

The commenter (2308-NSWA) suggests that the program's accomplishments speak for itself. The commenter cites the EPA's website:

Each year, Partners submit annual reports documenting their previous year's methane emission reduction activities. Since the inception of the Program, as of late 2021, Partners have eliminated 1.72 trillion cubic feet (Tcf) of methane emissions by implementing 153 cost-effective technologies and practices.

Response II-23-16: These comments are supportive comments; as such, no response is required.

### ***23.3.3 Oil and Gas Company Emissions Mitigation Efforts***

Comment: Commenter (2248-NDPC) states that given the many advancements in the oil and natural gas industry (e.g., equipment, drilling, completions, processing, technologies for sampling and analysis, and for controlling emissions) in the last decade alone, the commenter suggests that the EPA commission objective technical studies to explore and understand the 2023 oil and natural gas industry and not rely on technical documents written in the 1980s and 1990s.

Commenter (2179-KIOGA) states that the small businesses that make up the independent oil and natural gas industry recognize the importance of environmentally sound regulations to manage industry emissions, including methane. The commenter supports voluntary efforts by industry to reduce methane emissions. The commenter reports that their members are making constant improvements to the technology being used in the field to reduce, measure and report on emissions. The commenter states that they will continue to work with the Biden Administration as it considers initiatives to reduce methane and other GHG emissions.

Commenter (2172-KOGA) disputes that the oil and natural gas sector is the largest industrial emitter of methane as the EPA states. The commenter states that EPA's own data shows the reduction in methane and VOC emissions over time, with (post-2016) and without (pre-2016)

regulations imposed by EPA and that the data tables in prior rule makings do not support the EPA's claim that the oil and natural gas sector is the largest industrial emitter of methane. The commenter provides that data collected from the EPA's website shows that "waste" is the largest industrial emitter of methane in the U.S. (2021 data). The commenter notes that using the database provided by the EPA and filtering for only methane emissions, the "waste" category emits almost 93 million metric tons of CO<sub>2</sub>e verses the petroleum and natural gas systems segment at less than 71 million metric tons of CO<sub>2</sub>e. Reference: <https://ghgdata.epa.gov/ghgp/main.do>.

The commenter (2172-KOGA) also provides that, according to the Global Methane Initiative (GMI), the oil and natural gas sector is not the largest industrial emitter (See Figure 1 (of their comment letter): Emissions by Sector in million metric tons of carbon dioxide equivalent (MMTCO<sub>2</sub>e)). [Table 1 of their comment letter lists sources of methane emissions, where "waste" is listed as a greater contributor to methane emissions than the oil and natural gas sector. However, no values are shown. (See Reference: <https://www.globalmethane.org/methane-emissions-data.aspx>).]

Commenter (2163-EOS Federated Hermes) states many oil and gas companies have already demonstrated the feasibility of substantially reducing methane emissions using existing technologies at a reasonable cost. The commenter reports that members of the Oil and Gas Climate Initiative (OGMP) 2.0, including a range of large and small, publicly-traded and privately-owned companies such as ConocoPhillips, Occidental Petroleum, EQT, Devon, Pioneer, EOG, Diversified Energy, PDC, Crescent Energy, Civitas, Jonah Energy, TRP, as well as Cheniere<sup>43</sup>, Shell, BP, Equinor, Total Energies, Repsol, Eni, Petrobras, and non-signatories such as Chevron, Exxon and many others, have voluntarily committed to reducing the collective average methane intensity of aggregated upstream oil and gas operations to well below 0.20 percent by 2025.<sup>44</sup> However, methane emissions of many U.S. companies are much higher than 0.20 percent and only one third of all U.S. operators currently have plans to reduce methane and flaring emissions.<sup>45</sup> The commenter supports strong regulations to provide accessibility to emissions reductions technologies and accelerate industry-wide methane reduction. They suggest that strong regulations will benefit companies, the economy, the country, and the financial system.

Commenter (2308-NSWA) states that they support the efforts of the Environmental Partnership, which is an oil-and-gas-companies-led effort that focuses on solutions that are technically feasible, commercially proven, and will result in significant methane emission reductions. The commenter provides that efforts are focused on addressing blowdowns, venting, leak detection and repair (LDR), and liquids unloading.

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<sup>43</sup> Partners-OGM Partnership [<https://www.ogmpartnership.com/partners>].

<sup>44</sup> An Investor's Guide to the Oil and Gas Methane Partnership 2.0. [<https://www.globalmethane.org/resources/details.aspx?resourceid=5197#:~:text=An%20Investor%E2%80%99s%20Guide%20to%20the%20Oil%20and%20Gas,guidance%20to%20investors%20on%20the%20OGMP%E2%80%99s%20reporting%20framework>].

<sup>45</sup> Dallas Fed Energy Survey [<https://www.dallasfed.org/research/surveys/des/2021/2104.aspx>].

Similarly, commenter (2241-UDNR) states that the oil and gas industry is already making strides to reduce gas emissions voluntarily. For example, the American Petroleum Institute (API) has formed “The Environmental Partnership,” which, as of 2021, represents 100 companies that make up more than 70 percent of the U.S. onshore oil and natural gas industry, reflecting the growing commitment to driving innovation, sharing best practices, and increasing transparency to reduce methane emissions in every major U.S. basin. In 2021, the commenter reports that the Environmental Partnership continued to make progress across all six environmental performance programs – including reducing flaring, replacing gas-driven pneumatic controllers with low- or zero-emitting devices, and reducing leak occurrence rates to 0.05 percent among the nearly 100,000 sites surveyed.

According to the 2022 Annual Report of the API’s Environmental Partnership the 100 participating oil and natural gas companies, the commenter (2241-UDNR) provides that in efforts to detect and repair leaks in the year 2021 alone, combined to do more than 345 million component inspections, conduct more than 460,000 leak detection surveys at over 90,000 sites and found a leak occurrence rate of only 0.05 percent. The commenter adds that the same companies replaced or removed from service over 22,400 gas-driven pneumatic controllers and installed over 4,500 zero-emission pneumatic controllers at new sites. More than 1,700 high-bleed pneumatic controllers were replaced, retrofitted, or removed from service and 60 of the 100 companies participating in this partnership no longer have high bleed pneumatic controllers in their operations. During 2021, the companies monitored more than 39,000 manual liquids unloading events and emission reduction practices were implemented during more than 7,800 pipeline blowdowns. Rod packing changes were made on over 3,200 reciprocating compressors and emissions reduction practices utilized on more than 1,500 compressor sites. Data from 2018 to 2021 industry efforts are even more impressive: More than 700 million component inspections were performed; 1.2 million leak detection surveys conducted; more than 51,000 gas-driven controllers replaced; and more than 10,000 zero-emission pneumatic controllers were installed.

The commenter (2241-UDNR) adds that companies participating in the API’s Environmental Partnership program have also been doing their part to reduce the flaring of natural gas. Since the launch of the flare management program in 2020, the Partnership has advanced best practices to reduce flare volumes, promote the beneficial use of associated gas and improve flare reliability and efficiency when flaring is necessary. To track progress, participants in the program annually report data to calculate flare intensity, a measurement of flare volumes relative to production. The annual report reviews flaring trends and reduction efforts and participants collaborate to share information on flare management programs that includes best practices and utilization of innovative technologies to reduce flaring intensity. The commenter reports that there was a 40 percent increase in the number of participating companies in the flare management program in 2021. These companies represent 62 percent and 40 percent of total U.S. oil and natural gas production, respectively. Including new company participants, the commenter reports that there was a 45 percent reduction in flare intensity and a 26 percent reduction in total flare volumes from the previous year.

In addition to the successes of the API’s Environmental Partnership, the commenter (2241-UDNR) notes that another program worth pointing out is the Utah Petroleum Association’s “Latch the Hatch” program that has voluntary commitments from several operators in Utah to



aggressively detect and mitigate leaks from wells and production facilities. The commenter reports that the results of last year's efforts were reported at the November 2022 Uinta Basin Oil and Gas Collaborative Meeting held in Duchesne, Utah. A video recording of that meeting was made and can be viewed on YouTube at the following link:

<https://www.youtube.com/watch?v=yRpGwrnsMpo>. The commenter states that a panel discussion of companies participating in "Latch the Hatch" can be viewed at time point 1:48:42, and they emphasize that the reported results are impressive.

Response II-23-17: The EPA applauds the effort and results that the oil and natural gas industry have achieved.

### ***23.3.4 State Agencies***

Comment: Commenter (2329-Sierra Club LSC) reports that their main environmental agency, the Texas Commission on Environmental Quality (TCEQ), does not generally require leak detection and repair (LDAR) for most permits, and generally only regulates VOC emissions in nonattainment areas. The commenter provides that an estimated 5 percent of permits in the analysis currently are requiring LDAR for oil and gas operations, meaning 95 percent are not. While they recently updated standards on VOCs in non-attainment issues, the commenter states that they fall far short of protecting communities, and do not include real methane standards for issues like leaking storage tanks. That is why they believe the proposal is so important.

Commenter (2329-Sierra Club LSC) adds, as can be seen from comments filed by the TCEQ and Texas Railroad Commission, there is opposition from the state agencies to the new proposed rule. Thus, the commenter states they will need help not only in implementing a strong protective rule, but oversight in its eventual implementation. The commenter requests that the EPA work with Texas agencies and industry to make sure that the rules are clear and that the timelines can be implemented. The commenter contends that, although there will be opposition (political) they need EPA's help to overcome that opposition and they are counting on the EPA to assure the job gets done.

Commenter (2334-Liveable Arlington) states that they need better protections to safeguard themselves, their families, and future generations. They contend that their local government and the state of Texas and the TCEQ have failed them. They assert that the rules and monitoring systems required for urban drilling in places like Arlington and its neighboring cities in the Barnett shale must be stringent, with severe penalties for non-compliance. Given what global fossil fuel giants, their city and state, subject their children to every day, the commenter asked for the following when methane rules were proposed last year by the EPA:

1. 24-hour air monitoring at the fenceline for new and existing wells and drilling infrastructure like compressor stations within 1500 feet of homes, schools, preschools, daycares, and medical centers. When air monitors show elevated levels of HAP, it should automatically trigger LDAR.
2. Immediate deployment of the best available emissions control technology.
3. Monthly Leak Detection and Repair for all new and existing wells.

4. End the wasteful and dangerous practice of the routine flaring (lit and unlit) of natural gas at oil and gas facilities.
5. Creating emissions monitoring programs with community involvement and data reported in real time.

Response II-23-18: See Response II-23-14 of this Chapter. In response to comments that the EPA should end wasteful flaring, the EPA, as a result of information provided through the public comment process, is finalizing revisions to the proposed requirements to limit routine flaring of associated gas. During the comment period, the EPA received extensive information regarding the availability and cost-effectiveness of alternatives to routine flaring, state-level requirements to limit or prohibit routine flaring, and commitments that owners and operators have already made voluntarily to phase out routine flaring in the near future. Based on this information and the EPA's updated BSER analysis, the EPA is finalizing requirements to prohibit routine flaring of associated gas from newly constructed wells that are developed after the effective date of the final rule.

Comment: Commenter (2401-State of Wyoming) believes Wyoming has successfully balanced conservation and exploitation of its minerals and is the best suited to be the environmental regulator. They report that they are leaders in regulating emissions from oil and gas facilities across the state. Wyoming's regulations are tried and tested and represent the most efficient process for protecting our environment. Specific to this proposed rule, Wyoming's DEQ and WOGCC are charged with preventing the waste of oil and gas and have authority over drilling, flaring, operations, production, and permitting. Wyoming has an extensive monitoring and inspection program for all oil and gas wells. While not specifically addressed in this proposal, the commenter states that it is important to note that Wyoming has been dedicated to the plugging and abandonment program for orphan wells, where Wyoming leads the nation. Even without the recent influx of federal funding, they report that all their known remaining orphan wells will be plugged in the near future.

Response II-23-19: The EPA acknowledges and commends Wyoming in their dedication to the plugging and abandonment program for orphan wells.

## **23.4 Public Comment Period/Scope**

### ***23.4.1 Public Comment Period Adequacy (i.e., Request for Extension, Inadequate Time Provided)***

Comment: Several commenters (1663-WVOAG, 1673-WEA, 1583-ODEQ, 1586-NACAA, 1587-DGCC, 1588-API, 1589-PCPBC, 1592-UPA, 1590-AXPC, 1591-GPAMA, 1594-BH, 1595-PW, 1604-PAE, 2200-NUEO, 1612-NDPC, 1619-IPANM, 2020- Mississippi Department of Environmental Quality (MDEQ), 2220-WDEQ, 2227-WEA, 2237-ICND, 2238-SOOGA, 2246-IPAA, 2257-MOGA, 2294-OOGA, 2297-Petro-Vest, 2321-AED, 2322-ADEE, 2330-KDAQ, 2437-MEC) state that the timeframe for comment was inadequate, citing several reasons for why they believe a longer comment period was warranted:

- The supplemental proposal comment period includes three major holiday periods.
- The proposed rule is one of the most complex and expansive regulatory programs the EPA has ever proposed.
- The proposed rule included over 500 pages with an additional 400 pages of regulatory impact analysis and 150 pages in *Federal Register*.
- Vagueness over the intention and focus of proposed actions and regulations made providing adequate comment and response a daunting task given the short response time.
- Far reaching impacts on the industry as well as tribal, state, and local authorities
- The proposed regulation will cover roughly 700,000 sources not previously subject to air quality regulations with an extremely high number of sources in certain states.
- December 2022 supplemental proposal, when finalized, will set in motion the process of controlling approximately 700,000 to one million sources, with a large majority of which have not been previous controls.
- A disproportionate effect on states, with few states have significant impact of number of sources.
- Several hundred pages of the supplemental proposal and supporting documents identifies key changes from the November 2021 proposal.
- The first look at the supplemental proposal was in mid-November 2022, and the supplemental regulations were not published in the *Federal Register* until December 6, 2022.
- Supporting documentation such as RIA and regulatory text not provided with original proposal.
- The proposal is well beyond the EPAs appropriate statutory authority and usurps the role of the states.
- The proposed rule affects a very large number of stakeholders.
- There are at least 142 areas/topics for which the EPA is soliciting comment.
- The regulatory and administrative burden on state authorities and small business across the country is significant.
- States have limited resources for review and analysis of such a large and far-reaching proposal.
- The proposal has potential repercussions on the state's approach to permitting, compliance monitoring, regulatory enforcement, and emissions inventory reporting.
- The rule poses an extraordinary challenge to the states and tribes' air program budget and resources as it will require legal interpretation, evaluation of state regulations and effect of state energy needs, analysis and potentially modeling of impacted sources, evaluation of emission inventories, consultation with stakeholders, and examination of compliance and enforcement needs.
- The new calendar year is a critical time in many states and for natural gas operators to compile, analyze and then report emissions data regulatory agencies.
- The EPA has not suggested that these changes are an emergency necessity, and no statutory mandate or court order would make it one.
- Neither the EPA nor any other party would be prejudiced by an extension
- There have been problems with documentation provided in the docket.
- The proposal includes requirements for a new Super Emitter Response Program. The commenters contend it will take additional time and effort to develop a better estimate of the cost of control and monitoring using a more accurate statistical approach than what the EPA

appears to have addressed in this proposal; in addition to assessing remaining useful life and other factors for the Program. The commenters contend that program alone warrants an extension of the comment period.

- Commenters state that the EPA is forcing an arbitrary and unwarranted rulemaking timeline while providing no justification for not extending the comment period.
- The EPA must provide for real and substantive review of the proposed regulations to prevent unfairness in the process and what they believe would be a pre-ordained sham result.
- The commenters note the proposal requirements and comment period overlap with many other interrelated regulatory actions:
  - Implementing regulations for Section 111(d) of the Clean Air Act.
  - An important revision to the definition of “Waters of the United States” under the Clean Water Act.
  - The EPA’s Request for Information on the Inflation Reduction Act (IRA) Methane Emissions Reduction Program (MERP).
  - Bureau of Land Management (BLM) Waste Prevention, Production Subject to Royalties, and Resource Conservation rule.
  - Federal Implementation Plan for Oil and Natural Gas Sources on the Uintah and Ouray Indian Reservation (U&O FIP).
  - State actions such as Pennsylvania’s new regulatory scheme regarding volatile organic compounds (VOC) for existing unconventional natural gas sources, to be published and take effect on December 10, 2022.

Commenter (2401-State of Wyoming) is concerned that EPA largely ignored the comments that were submitted by the Wyoming Department of Environmental Quality (WDEQ) on January 31, 2022, and has not engaged in meaningful dialog with Wyoming state agencies. The commenter calls to attention, for example, that DEQ submitted a 30-day comment period extension request for the supplemental proposal on December 14, 2022. EPA never responded to WDEQ’s request. Furthermore, they add that the State of Wyoming was never consulted during the development of the December 2022 supplemental proposal — The commenter understands that many other states have expressed this same concern.

Commenter (2257- MOGA) states that more time was necessary to address the concerns and comments of the participating Small Entity Representatives (SERs) submitted on July 13, 2021, and following the initial Small Business Advocacy Review (SBAR) panel discussion. The commenter’s small businesses do not have sufficient staff dedicated to understanding the proposed rules and regulations.

Another commenter (1590-AXPC) notes that the EPA has often granted extended timeframes to allow for more thorough public comment. For example, for the original NSPS OOOO proposal in 2011, the commenter provides that EPA extended the comment period to 90 days, and in one of the few similar examples of the EPA also proposing existing source guidelines under CAA section 111(d) (the Clean Power Plan (CPP)), the EPA first proposed 120 days of public comment and later extended public comment to nearly six months.

Commenter (2246-IPAA) states that the EPA is proposing to change regulations as they pertain to the oil and gas industry specifically while simultaneously proposing to make changes more

generically for CAA section 111(d) at 40 CFR, Part 60, subpart Ba. While the potential for “moving the goal posts” for states is great, the commenter believes that the EPA was unwilling to grant states and stakeholders even an additional two weeks to comment and coordinate the close of the comment period on two rulemakings that are clearly related and intertwined. The commenter continues that the EPA’s response to stakeholder’s request for additional time was very much akin to a parent’s response to a child questioning the parent’s directive (i.e., “because I said so”). While the commenter believes that may be an acceptable response from parent to child, the commenter questions whether such a decision, in and of itself, is not arbitrary and capricious.

Several commenters specifically request that the EPA extend the comment period as follows:

- Several commenters (1586-NACAA, 1599-WDEQ, 1600-AAPCA, 1623-PDEP, 2237-ICND, 2310-MDEQ) requests at least a 30-day extension.
- Several commenters (1583-ODEQ, 1588-API, 1590-AXPC, 1591-GPAMA, 1592-UPA, 1593-PAO, 1601-TCEQ, 1602-TRRC, 1604-PA, 1606-UIT 1614-AOGA, 1630-INGAA, 1645-OOGA, 1663-WVOAG, 1673-WEA, 2020-MDEQ, 2220-WDEQ, 2225-WSARC, 2227-WEA, 2257- MOGA, 2288-NDDEQ) request not less than a 60-day extension to the comment period. Specifically, the States of West Virginia, Alabama, Alaska, Arkansas, Georgia, Idaho, Indiana, Kentucky, Louisiana, Mississippi, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Tennessee, Texas, Utah, and Wyoming request a 60-day comment period extension.
- Several commenters (1582-MSD, 1587-DGCC, 1589-PCPBC, 1594-BH, 1595-PWE, 1612-NDPC, 1619-IPANM, 2322-ADEE) request a 90-day extension of the comment period.
- Several commenters (1598-KEEC, 2170-WGOC, 2204-LIP, 2211-LER, 2223-TAEP) request an unspecified extension of the comment period.

Commenter (2403-PAO) states they (and many other entities) requested a 60-day comment period extension as they believed the 60-day comment period was unreasonable for such a complex and lengthy rulemaking. In response to the EPA’s November 2021 proposal, they requested that the EPA’s forthcoming proposed supplemental rule provide at least a 120-day comment period. That did not occur. The commenter requests that EPA provide rationale and justification for limiting the comment period to 60-days.

Response II-23-20: The EPA did not grant an extension to the comment period on the December 2022 Supplemental Proposal.

Comment: Commenter (2294-OOGA) states that it is their understanding that the EPA, in recent conversations with other national and regional industry trade groups, has indicated that it will consider comments submitted after the February 13, 2023, deadline. The commenter urges the EPA to do so, but questions why the U.S. EPA would not do so formally via publishing a notice of an extended comment period. Notwithstanding, the commenter notes that if the EPA considers any comments submitted after the February 13, 2023, deadline, it must consider all comments submitted after the deadline. With that, to the extent that IPAA, AXPC or API submit comments after the February 13, 2023, deadline, the commenter supports, adopts, and incorporates by reference those comments herein.

Response II-23-21: The EPA considered all comments after the February 13, 2023, deadline up until September 20, 2023. While the EPA was not intent on doing this, some of the information obtained after the comment period closed as an outgrowth of meetings with stakeholders was accommodated and we therefore reviewed all late comments up until the date stated above.

Comment: Several commenters (1590-AXPC, 2248-NDPC, 2428-API, 2248-NDPC) specifically state that they were unable to provide a complete set of comments due to the time comment period time constraints. Commenter (2248-NDPC) notes that they are unable to submit comments for centrifugal compressors and sweetening units. According to commenter (2428-API), much of the information the EPA requested, as well as additional information that the commenter wanted to provide, is not included in their submitted comments due to what they believe are arbitrary and unnecessarily imposed timing constraints of the comment period for the December 2022 supplemental proposal.

Commenter (2248-NDPC) states that based on the extent of the proposals and the haste at which it is being pushed through the system, their comments have been necessarily limited in scope and detail. The commenter requests that for future rulemakings that the EPA be more proactive in their industry engagement so they can be better prepared before publishing proposed rules, and not be bundled with multiple proposed regulatory actions to give the public and regulated industry the time to participate efficiently and effectively. The commenter notes that publishing proposed actions not yet defined, along with a solicitation for the feedback on the addition of regulated sources, creates regulatory and financial uncertainty for the regulated community. The commenter asserts that silence by the commenter on any part of this proposal should not be interpreted as agreement or support. According to the commenter, time constraints and the complex nature of these rules have impacted their ability to respond to every piece of this proposal.

Response II-23-22: In response to commenters that state that they were unable to provide a complete set of comments due to comment period time constraints, the public also had access to pre-publication versions of the preamble and regulatory text for the December 2022 Supplemental Proposal on EPA's website.

The EPA has also engaged with pertinent stakeholders regarding their concerns throughout the rulemaking process. Stakeholders have included, but are not limited to, industry, small businesses, tribal nations, and communities most affected by, and vulnerable to, the impacts of the rule. See discussion section VII (Summary of Engagement with Pertinent Stakeholders) in the final rule preamble.

Comment: Commenter (1665-EEN) and its pro-life community have been pursuing methane reduction from the oil and gas sector since 2015. The commenter states that children having been waiting long enough under the clouds of toxins, VOC's and methane that threatened their health and lives. According to the commenter, there is no need to further delay action, and they strongly oppose any attempt to extend the comment period past the February 13, 2023, deadline. According to the commenter, extending the deadline would be an immoral affront to our children and an injustice to all Americans. The commenter recommends that, following the close of the comment period, EPA must act quickly to consider all public comments, strengthen the final rule

beyond the provisions in the supplemental proposal and promulgate a final rule under CAA section 111 by early summer 2023.

Response II-23-23: The EPA did not grant an extension to the comment period on the December 2022 Supplemental Proposal.

#### ***23.4.2 Scope of Public Comments Submitted Under the December 2022 Supplemental Proposal***

Comment: Commenters (2308-NSWA, 2446-IPAA) state that the EPA indicates in the proposed rule that it “is not reopening for comment any aspect described in the November 2021 proposal that the EPA is not proposing to substantively address or update in this supplemental proposal.” The commenters state that they believe this is peculiar – if not contrary to the Administrative Procedure Act (APA). Furthermore, they add that no legal basis or justification for taking such a position is provided.

The commenters (2308-NSWA, 2446-IPAA) question whether the EPA has the legal authority to pick and choose what aspects of the November 15, 2021, publication to “reopen” for comment. The commenters contend that the appropriateness/legality of such position is even more in question when no regulatory language was provided in the original “proposal.” They inquire: How is it not arbitrary and capricious for the EPA to tell stakeholders what portions of a “proposal” is or is not open for comment?

Commenter (2446-IPAA) suggests that the EPA cannot have it both ways. If the EPA maintains its position that it has the authority/ability to choose what portions of a “proposal” are reopened for comment, then the commenter believes that the EPA should be precluded from responding to comments provided on the original “proposal” that were not addressed in a response to comment document placed in the docket prior to or concurrent with the supplemental proposal or addressed in the supplemental proposal preamble. The commenter states that various legal and technical arguments were raised by them and other trade associations, and certain states. In the December 2022 supplemental proposal, the EPA has elected to address some of the comments and has failed to address others while also indicating only certain issues would be open for additional comment during the limited 60-day comment period on the December 2022 supplemental proposal.

Response II-23-24: The EPA has considered and is responding to all timely comments received on the November 2021 and December 2022 proposals addressing the proposed requirements from both notices.

### **23.5 Public Hearing Allotted Time**

Comment: Commenters (1608-LA, 1681-PC50) request additional time be allotted at public hearings. According to the commenters, by December 14, 2022, at noon, all the slots for January 10, 11, and 12, 2023, were full. The commenters state that with almost 3 weeks left in the registration period, many people will find they have missed the opportunity to comment. While they understand that there is more time for written comments, they state that many people are

unable to navigate the websites for the EPA or Regulations.gov and find written comments difficult.

Response II-23-25: The EPA held a virtual public hearing January 10, 2023, through January 12, 2023, to provide the public the opportunity to present comments and information on the Agency's proposed updates to NSPS and EGs to reduce methane and other harmful pollution from the oil and natural gas industry. It is worth noting that the virtual public hearing was originally scheduled as a two-day hearing but due to the public's overwhelming interest, EPA extended the hearing an additional day. Over the course of three days, nearly 300 speakers (roughly 100 speakers per day), from members of the public either representing themselves or speaking on the behalf of one or more organization or agency, provided oral testimony.

Over 517,400 public comments were received on the December 2022 Supplemental Proposal. The EPA Docket Center consolidated mass mail campaigns, form letters and petitions into single DCNs, resulting in over 2,200 posted comments. Each of these comments were reviewed and significant comments relevant to this action have been considered – *i.e.*, comments not considered are duplicates, and comments withdrawn or unrelated/non-applicable to the December 2022 Supplemental Proposal.

## **23.6 Regulatory Text**

Comment: Commenters (2168- INOGA, 2172-KOGA) state that regulatory text must be provided for review and comment prior to actions being required by the oil and gas industry. The commenters note that the December 2022 supplemental proposal is like the November 2021 proposal, with only preamble text released. The commenters contend that the regulated community does not know what the real, or full extent of the regulation will be until the regulatory text has been released. The comments provided on the December 2022 supplemental proposal are based on their understanding of how the regulation will impact their businesses, only based upon reading the preamble and not reading regulatory text that will be used to consider compliance and for enforcement hearings. The commenters believe that the regulatory text should be released for the regulated community to review and provide comment prior to actions being required by the oil and gas industry. They add that they view this release of the preamble as another Advanced Notice of Proposed Rule Making, where EPA is collecting comments in preparation for releasing the formal regulatory code for review and comment by industry.

Response II-23-26: The EPA released proposed regulatory text with the December 2022 supplemental proposal, reflecting the proposed new subparts NSPS OOOOb and EG OOOOc, as well as the proposed Appendix K. The December 2022 supplemental proposal preamble directed the public to memoranda to the docket for each subpart that could be found at Docket ID No. EPA-HQ-OAR-2021-0317, and which supplemented the redline versions of NSPS OOOO and NSPS OOOOa provided in the November 2021 proposal (Docket ID Nos. EPA-HQ-OAR-2021-0317-0095 and EPA-HQ-OAR-2021-0317-0097). The EPA also posted the proposed regulatory text to the EPA's website at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-new-source-performance> (for NSPS OOOO, NSPS OOOOa, and Appendix K), and at <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas->



industry/epa-issues-supplemental-proposal-reduce (for NSPS OOOOb, EG OOOOc, and revised Appendix K).

The commenter makes a vague assertion that the regulatory text should be released for the regulated community to review and provide comment prior to actions being required by the oil and gas industry, but the commenter does not claim any actual difficulty in finding or commenting on the proposed rule language. The EPA's approach was not prejudicial to the commenter or any member of the public. The notice of proposed rulemaking clearly explained the proposed changes to the NSPS regulations and the proposed EG. In addition, as stated in the notice, the EPA publicly provided in the rulemaking docket and on EPA's website a memorandum with the redline strikeout version of subparts containing the edits to the CFR that would be necessary to incorporate the proposed changes.

The proposals met all APA and CAA notice-and-comment requirements. Nothing in the APA or the CAA, requires EPA to publish proposed rule text in the *Federal Register*. The requirement to publish a "notice of proposed rulemaking" is not a requirement to publish "proposed rule text." CAA section 307(d)(3) specifies the required elements of a "notice of proposed rulemaking," and "proposed rule text" is not a required element. The elements that are required to be included in the notice of proposed rulemaking (a "statement of basis and purpose," "a summary of . . . the major legal interpretations and policy considerations underlying the proposed rule, etc.") were included in the proposed rulemakings.

The APA does not require publication of proposed rule text in the *Federal Register* either. Section 553(b)(3) of the APA provides that a notice of proposed rulemaking shall include "either the terms or substance of the proposed rule or a description of the subjects and issues involved." Thus, the APA clearly provides flexibility to describe the "subjects and issues involved" as an alternative to inclusion of the "terms or substance" of the proposed rule. See also *Rybachek v. EPA*, 904 F.2d 1276, 1287 (9th Cir. 1990) (EPA's failure to propose in advance the actual wording of a regulation does not make the regulation invalid where EPA's discussion of the regulatory provisions "clearly describe[s] 'the subjects and issues involved.'").

Although in the past the EPA has at times published proposed amendatory regulatory text, the EPA's practice has varied. See, e.g., Hazardous Air Pollutants: Proposed Regulations Governing Constructed, Reconstructed or Modified Major Sources, 59 FR 15504 (April 1, 1994) ("The proposed regulatory text is not included in the Federal Register notice, but is available in Docket No. A-91-64 or by request from the EPA contact persons designated earlier in this note. The proposed regulatory language is also available on the Technology Transfer Network (TTN), of EPA's electronic bulletin boards."); Federal Standards for Marine Tank Vessel Loading and Unloading Operations and National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading and Unloading Operations, 59 FR 25004 (May 13, 1994) ("The proposed regulatory text and other materials related to this rulemaking are available for review in the docket."). Even when we do include the proposed text in the Federal Register, we often include a redline version of proposed regulations in the docket for rulemakings to assist the public in understanding the proposed regulatory changes. In our experience, stakeholders find the redline version far more useful than the proposed amendatory language in the format required by the Office of the Federal Register. Although appropriate for the task of revising the CFR, this

language can be difficult to assess without the accompanying full regulatory text. Given this, and given that we rarely receive comments on the proposed amendatory language or on proposed regulatory language at all, we determined that for rulemakings such as these, it would be more efficient to take the approach here of making both easily accessible but not including the proposed amendatory text in the notice.

Comment: Commenter (2257-MOGA) states that the proposed regulations published by the EPA on December 6, 2022, did not offer a specific regulatory framework or text. Small business entities with minimal staff and limited resources need direct, well-defined, and easily understood proposed regulations to evaluate for impacts and provide meaningful comment. Further, the commenter states that the approximately 500 pages in the current proposed regulations combined with reference to NSPS OOOO, NSPS OOOOa, the Methane Rollback NSPS OOOOa, the initial NSPS OOOOa, NSPS OOOOb and EG OOOOc proposal and references to an unpublished “presumptive standard” to be proposed in 2023 overwhelmed the majority of the commenter’s constituents and made proposed regulations very unclear and not easily understood. The commenter states that that clear definition between what specifically was being proposed, when juxtaposed to past regulations and unpublished future regulations, made the immediate understanding of proposed impacts to many small business’ nebulas unattainable. According to the commenter, many of their members questioned the EPA’s direction and asked whether the EPA had intended the proposed regulations to be an “Advanced Notification of Future Rule-Making” since the EPA was soliciting numerous responses to questions, while simultaneously proposing non-specific and what they believe were unclear future regulations. The commenter suggests that this lack of clarity and confusing language significantly prevented many of the commenter’s constituents from fully understanding the proposed regulations and prevented meaningful and substantive comments on the potential short-term and long-term implications of proposed regulations that will affect small and very small businesses.

The commenter (2257-MOGA) adds that they support the comments made by the Independent Petroleum Association of America (IPAA) regarding issues of regulatory framework. The commenter recommends the EPA provide clear, well-defined, and easily understood proposed regulations that can be understood by all businesses, including small and very small businesses without environmental and legal staff. They recommend regulations include clear definitions of major equipment, calculation methodologies with samples, well-defined source definitions aligned with the 1979 CAA, and clarification of exemptions.

Response II-23-27: The December 2022 Supplemental Proposal regulatory text for the NSPS OOOOb, EG OOOOc and Appendix K was accessible via EPA’s website for this action and the EPA Docket established for this rulemaking.<sup>46,47</sup> See also Response II-23-26 of this Chapter.

Comment: Commenter (2220-WDEQ) states that the EPA issued the December 2022 supplemental proposal in the *Federal Register* as a roughly 150-page document containing no regulatory text. They acknowledge that the regulatory documents associated with the

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<sup>46</sup> <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce#Additional>.

<sup>47</sup> For the proposed NSPS OOOOb regulatory text, see Docket ID Number EPA-HQ-OAR-2021-0317-1551; for the proposed EG OOOOc regulatory text, see Docket Number EPA-HQ-OAR-2021-0317-1552.

supplemental proposal (NSPS OOOOb, EG OOOOc, Appendix K) were included as attachments to the December 2022 supplemental proposal but expressed that viewing the regulatory documents required that the general public navigate through EPA’s website, or sort through an abundance of additional documents related to the December 2022 supplemental proposal on the docket, to access. The commenter contends that this is a misleading practice that severely lacks any form of transparency, and dramatically underrepresents the size of the proposed regulations (which consists of a total of more than 750 pages in length counting the preamble) and the time and resources to review them. Furthermore, the commenter expresses that the EPA has placed the onus on the general public to gather all the associated attachments rather than including them as one body of proposed text. The commenter notes that the EPA has undertaken this non-transparency practice recently with other proposed rules. The commenter considers this to be an inappropriate and exclusionary practice that is inconsistent with EPA’s own principles of meaningful engagement required under the December 2022 supplemental proposal.

Response II-23-28: See Response II-23-26 of this Chapter.

Comment: Commenter (2237-ICND) states that the EPA failed to provide fair notice of the December 2022 supplemental proposal’s rule text because the proposal did not contain proposed regulatory text. The commenter therefore believes that the December 2022 supplemental proposal is deficient, departing from the long-established practice of publishing the proposed regulatory text in the *Federal Register* notice and instead burying it in the administrative record. The commenter contends that this combination of actions raises substantial “fair notice” concerns. They add that it is also inconsistent with EPA’s commitment to EJ and transparency since many communities will not find it easy or customary to pore through the administrative record. According to the commenter, whatever formalistic legal arguments EPA might make that it has complied with the APA public notice requirements, it is indisputable that burying proposed regulatory text in the administrative record is neither transparent, nor does it promote or enable broad and diverse public participation.

Response II-23-29: See Response II-23-26 of this Chapter.

## **23.7 Meaningful Engagement with Industry**

Comment: Commenters (2223-TAEP, 2254-PBPA) state that for the proposed NSPS and EG, the EPA is relying on its previous work on methane — namely 40 CFR, Part 60, subpart OOOOa, the NSPS for VOC and methane emissions from the oil and natural gas sector (referred to as the “2016 Methane Rule”). The commenter recommends that before the EPA finalizes any methane regulation, that it works in partnership with the domestic oil and gas industry – especially small and mid-sized producers — toward a path that ensures the best way to reduce global emissions while encouraging and maintaining innovation. The commenter recommends that such work should focus on flexible partnership-based approach to identifying advanced environmental technological approaches to exploration and production activities – a more effective means to a better environment rather than a heavy regulatory “one size fits all” mandate.

Response II-23-30: See section VII (Summary of Engagement with Pertinent Stakeholders) of the final rule preamble for EPA’s extensive outreach with the public, states, tribal nations, and a

broad range of pertinent stakeholders in order to gather information from a variety of viewpoints. Throughout the rulemaking process the EPA has met individually with hundreds of industry representatives, non-governmental organizations (NGOs), technology vendors, academics, data companies, and others.<sup>48</sup>

## **23.8 Emissions Control Vendor Information**

Several commenters provide information to the EPA on their emissions control technologies that they advocate could be used by oil and natural gas facilities to mitigate VOC and or methane emissions. Technologies highlighted by commenters are highlighted below.

### ***23.8.1 Digital Flare Mitigation Technology***

Comment: Commenter (2175-Crusoe Energy) responds to EPA’s solicitation that “additional information on potential emerging technologies that provide uses for the associated gas in a beneficial manner other than routing to a sales line, using as a fuel, or reinjecting the gas.” The commenter believes that Crusoe’s digital flare mitigation (DFM) is just such a technology. The commenter provides that their DFM technology harnesses stranded and wasted energy resources to power advanced computing systems or for use onsite by operators and has reliably demonstrated its ability to exceed the BSER standard of 95 percent methane reduction—representing the type of emerging technology that should be considered a beneficial use for oil and gas operators to comply with the standards of performance for oil wells with associated gas. More details about their DFM technology and its applications are included as Appendix A to their comment letter.

The commenter (2175-Crusoe Energy) adds that their generators exceed the BSER standard requiring control devices to achieve at least 95 percent reduction in methane and VOCs, emissions, with a calculated combustion efficiency averaging 99.9 percent in 2022, determined from stack tests conducted at least annually to meet 40 CFR Part 60 Subpart JJJJ requirements. By comparison, the commenter notes that the latest research from the University of Michigan found that observed destruction removal efficiency of open flares was on average only 91.1 percent. In other words, they state that about 9 percent of the methane directed to a flare escapes to the atmosphere compared to 0.1 percent with DFM. Based on these numbers, the commenter states that their DFM technology prevented an estimated 2,700 metric tons of methane from escaping into the atmosphere. Because methane has a 20-year global warming potential (GWP)—82.5 times that of carbon—their 2021 methane emissions reductions translated to over 220,000 metric tons of CO<sub>2</sub>e (mtCO<sub>2</sub>e) emissions avoided. In total, they report that their currently deployed fleet of DFM systems have the capacity to reduce an estimated 800,000 mtCO<sub>2</sub>e per year, comparable to removing approximately 170,000 cars from the road for a year. Since the company was founded in 2018, the commenter notes that their company has prevented over 4 billion cubic feet of gas from being flared. They note that their DFM technology offers oil producers an economic, operationally practical, and usually cost-free alternative to natural gas flaring, harnessing stranded and wasted energy for productive use. They add that they have robust in-house logistics, supply chain, engineering, and operations capabilities, which enable

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<sup>48</sup> See various stakeholder meeting memoranda reflected in EPA’s Docket ID No. EPA-HQ-OAR-2021-0317.

them to deploy and commission DFM systems within one week and operate them with the highest environmental and safety standards.

The commenter (2175-Crusoe Energy) reports that their DFM systems are deployed directly to the oil wellsite to convert the stranded gas, which would otherwise be wasted and flared, into electricity that is used to power modular data centers. These data centers support computer-intensive applications, including Crusoe Cloud, a company cloud computing platform for high performance computing (HPC), computational biology, artificial intelligence, 3-dimensional rendering and other HPC workloads, and cryptocurrency transaction processing (“mining”). They state that it can also be used to generate electricity that can be used onsite by operators, which can be particularly beneficial at remote locations where electricity might not otherwise be available. In many circumstances, the commenter notes that their company purchases the associated gas from the operator for a nominal fee and covers the costs associated with delivering the equipment to the site. As a result, in many situations, the commenter states that operators who do not otherwise have access to sales lines are able to reduce their methane emissions without incurring significant additional costs.

The commenter (2175-Crusoe Energy) continues to report that their methane mitigation solution is also modular and highly scalable. They explain that DFM systems can manage gas volumes as low as 300,000 cubic feet per day, with no functional maximum. The commenter provides that their company has worked with operators of all sizes to deploy DFM systems that range from generators with a capacity of 2MW (consuming 300,000 cubic feet of flared gas per day) to a turbine with a capacity of 15MW (that can utilize over 2 million cubic feet of flared gas per day). In areas with multiple flaring well pads, the commenter provides that they have developed a system of centralized delivery points to increase efficiency and reliability. Further, they report that they can provide long-term services allowing operators to continue developing the acreage. As wells decline or have access to gas gathering, the commenter states that their company can decrease modules to adjust to the total gas supply.

Commenter (2175-Crusoe Energy) states that EPA noted in its proposal that it is soliciting comments on more specific technologies that have been proven to be viable in the field to utilize associated gas and avoid venting or flaring. The commenter responds that their Crusoe [Digital Flare Mitigation] DFM system is just such a proven technology. The commenter reports that their DFM technology is already commercially available and has proven to be scalable and reliable. Currently, they report that they have over 120 mobile data centers deployed across oil fields in Colorado, North Dakota, and Montana, with continued expansion planned domestically, and soon, internationally. They add that their DFM systems are designed to run year-round and to comfortably operate in temperatures from –20°F to 100°F, while warm weather units can comfortably operate up to 105°F. The commenter notes that they have successfully operated below and above this temperature range by deploying precautions and operational protocols that minimize outages. They further add that their generators are contained in metal enclosures, which have louvers and fans for summer months, and building heaters or oil and water heating systems that automatically turn on if the unit goes down in the winter, so they can be restarted.

Commenter (2175-Crusoe Energy) further reports that their company’s warm weather systems, designed to operate in hotter regions like Texas, are not enclosed but do have canopies over the

electrical equipment, rain louvers over the engine air intake, and air filters to combat sand and dirt. In the summer, they note that they can reduce the load on the engine if it is running hot or shut off individual computing units that are at risk of overheating. They explain that they mitigate such risks as much as they can through ensuring proper louver positions on our data centers and making sure the box filters are clean. They add that they also have video monitoring in most locations so we can adjust louvers and respond quickly before issues arise. They further add that they also have software that automatically notifies mechanics or mining technicians, who provide 24/7 on call support and response to problems. Through July 25, 2022, they report that their uptime exceeded 98 percent, excluding storms, low gas (where operators did not provide the DFM technology with enough gas to operate), and planned maintenance. The commenter states that their company's DFM technology also has a proven track record of operational safety. Over the past two years, they add that they have recorded over 500,000 man-hours worked without a recordable injury to an employee or contractor.

The commenter (2175-Crusoe Energy) goes on to report that their company's DFM technology also provides additional GHG reduction benefits for oil producers, upstream operators, and the public. Due to the lower combustion efficiency of open flares and the leakage of highly potent methane into the atmosphere, the emissions associated with the gas that would have been flared in the absence of their technology/support would be nearly 70 percent higher than their accounted Scope 1 emissions. Additionally, they add that had the same computing assets been powered by connecting them to the grid rather than using flared gas, those assets would have generated an additional 85,000 mtCO<sub>2e</sub> emissions based on the U.S. grid average. By explicitly including DFM or similar technologies as listed beneficial uses that can qualify in meeting BSER in any final rule, the commenter believes that the EPA can help to further reduce methane emissions while generating positive social benefits and without causing operators to incur additional costs.

The commenter (2175-Crusoe Energy) further reports that their company recently completed a full accounting of the company's 2021 emissions using the GHG Protocol's Corporate Accounting and Reporting Standard. In 2021, they found that their technology/support reduced flaring by nearly 1.7 billion cubic feet of natural gas. In addition, they also calculated its "avoided emissions," sometimes referred to as Scope 4, to paint a more complete picture of the company's positive and negative GHG impacts, using one common definition for Scope 4 as "GHG emissions impact of a product relative to the situation where that product does not exist." In their company's case, this meant comparing the emissions from using their DFM systems to the emissions that would have resulted from the flaring of natural gas in its absence.

In sum, the commenter (2175-Crusoe Energy) concludes that their company's DFM technology has proven to be a win for both industry and the environment, and they respectfully submit that this is exactly the kind of emerging technology EPA's regulations should allow for and encourage.

Response II-23-31: The EPA appreciates the information provided by the commenter on their DFM technology.

### ***23.8.2 Advanced Catalytic Technology***

Comment: Commenter (1603-Thermon) explains that their company is a U.S. based global supplier of industrial heating equipment. They explain that they have recently developed a new product that is designed specifically for methane abatement using advanced catalytic technology. They provide that this new device is ideally suited for use with processing vented methane into water vapor and carbon dioxide at conversion rates of 90 to 98 percent. The commenter adds that the device is designed to run continuously and indefinitely without an electrical power source, and since the device operates at a low temperature, it does not produce NOx.

Response II-23-32: The EPA appreciates the information provided by the commenter on their use of advanced catalytic technology designed specifically for methane abatement.

### ***23.8.3 Instrument Air Package Information***

Comment: Commenter (1609-Qnergy) reports that, with respect to the size of compressors and generators, their company provides instrument air packages with rocking piston compressors that are as small as 1 horsepower (HP). The commenter adds that their 5 HP compressors (both scroll and screw) are driven by the PG5650 (5.6 kW Stirling generator). Further, they note that their company released triplet packages of more than 16 kilowatts (kW) (3 x PG5650) to power large compressors.

Response II-23-33: The EPA appreciates the information provided by the commenter on their instrument air packages.

### ***23.8.4 Pneumatic Electronic Controller Technology***

Comment: Commenter (2290-WedgeRock) notes that there is no mention of utilizing engineered gear technology to mitigate methane emissions. The commenter provides that high-efficiency worm and planetary gears can be coupled with an electric operator to provide more efficient controller. The commenter explains that high-efficiency gears can assist in helping motor operators achieve performance requirements such as speed of operation while reducing power required to operate the electric controller. According to the commenter, reducing power requirements in these applications make solar powered solutions more viable and cost effective.

The commenter (2290-WedgeRock) states that some commenters argue that emergency shutdown devices (ESDs) must be excluded from the affected facility definition due to functional needs. The commenter notes that they point to issues with electric and air-driven pneumatic controllers not being able to be operated in sufficient time to protect life and property. The commenter explains that the use of spring return gears coupled with electric operators provide a fail-safe electro-mechanical device that is an extremely reliable emergency shut-down device that does not utilize natural gas and therefore has an emission rate of zero. When coupled together, they add that an electric controller and a spring-return gear create a failsafe electric controllers can provide a robust solution to using natural gas-driven controllers in ESD situations. Upon a command to close the ESD valve, springs can be set to drive the valve to the emergency position in less time than natural gas-driven pneumatic controllers. According to the

commenter, the use of spring-return gears makes the use of electric operators much more viable in ESD situations and should be considered when discussing BSER.

The commenter (2290-WedgeRock) goes on to explain that spring return gear operators can also be used as stand-alone devices to create a manual-reset ESD. The gear utilizes a high-efficiency planetary gear that requires minimal turns to set in the ready mode and in an ESD situation, the spring is released and operates the valve. Spring-return gears can operate automatically as an ESD on loss of power, loss of pressure, or overpressure situations. This manual reset ESD can be activated utilizing a pressure transmitter and a solar powered remote controller in areas where power is not available or not reliable. A small solar system can power the transmitter, the remote operated controller, and wireless communications for the affected site. The Spring-return gears can also be activated by a low voltage signal from an operator's control room when an upset condition is identified or from a solar powered pressure transmitter with battery backup system. The commenter states that an operator can then inspect the area, take corrective action, and utilize the handwheel to reset the ESD once the situation is returned to normal. The commenter provides that, since both these options do not use natural gas, there would be no need for quarterly inspections, thereby minimizing maintenance costs.

To conclude, the commenter (2290-WedgeRock) suggests that the use of high-efficiency and spring-return gear operators should be considered as a technically feasible option. As noted, the commenter states that when a high-efficiency worm or planetary gear is coupled with an electric controller, the package can allow for reduced power consumption, making the use of solar powered electric controllers more reliable. The commenter adds that the use of spring return gears, when used alone can provide a manual-reset ESD that is extremely reliable. When a spring-return gear is coupled with a motor operator, the commenter notes that it can provide a failsafe electromechanical device that can be used to operate an emergency shutdown valve.

Response II-23-34: The EPA appreciates the information provided by the commenter on their high-efficiency spring return technology.

## **23.9 Performance-Based Compliance Alternative**

Comment: Commenter (2452-Hess) states that the EPA is soliciting comment on the potential use of intensity or production in the development of action levels, including appropriate thresholds for setting such action levels on both a short-term and long-term basis.”<sup>49</sup> The commenter believes that performance-based approaches offer opportunities to achieve emissions reductions that are equal to or greater than the reductions achievable by more prescriptive requirements, such as those included in the December 2022 supplemental proposal. Accordingly, the commenter requests that the EPA allow performance-based approaches as an alternative to demonstrate compliance with methane emissions reductions and provides further support for their request in the following paragraphs.

*Industry led efforts support performance-based standards.* The commenter (2452-Hess) reports that they are a founding member of the ONE Future Coalition – the exact type of industry-led

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<sup>49</sup> Id. at 74744.



effort the EPA referenced in its solicitation of comments. ONE Future is a group of companies from the natural gas industry focused on reducing methane emissions across the natural gas value chain. ONE Future adopts a performance-based approach to emissions reduction, focusing on the outcome – emissions reductions – rather than on specific technical or operational controls. The goal of ONE Future is to voluntarily lower methane emissions to less than 1 percent of gross methane production across the U.S. value chain by 2025. Peer reviewed analyses indicate that a leak/loss rate of 1 percent or less across the U.S. natural gas value chain provides immediate GHG reduction benefits. ONE Future believes that by orienting our activities toward this specific and measurable outcome, companies can achieve a sustained focus on identifying the opportunities for emissions abatement that yield the greatest benefit for the least cost. It grants individual companies the flexibility to choose precisely how they can most cost-effectively and efficiently achieve their goal, which could include deploying an innovative technology, modifying a work practice, or in some cases, replacing a high-emitting asset with a low-emitting asset.

The commenter (2452-Hess) states that the EPA has endorsed the ONE Future Coalition’s efforts through its Methane Challenge Program. Companies that join the Methane Challenge Program can choose one of two commitment options – the Best Management Practice Commitment Option or the ONE Future Intensity Commitment Option. The ONE Future Coalition’s approach remains an effective means of emissions reductions and The EPA should continue to endorse it through this rulemaking. In support of our GHG emissions and flaring intensity reduction targets, the commenter tracks and monitors air emissions at each of our assets and undertakes a variety of emissions reduction initiatives.<sup>50</sup> Based on this experience, the commenter believes that regulations that mandate the adoption of specific technologies, practices, and procedures for all facilities or operations of a certain type are less effective and efficient than performance-based approaches. Prescriptive requirements may not be effective in every operational situation, as conditions can vary between producing fields (e.g., Permian Basin versus Bakken) and individual well sites. In addition, prescriptive requirements can quickly become outdated with rapid improvements in emissions control technology or oil and gas production equipment or methods. In contrast, performance-based standards facilitate innovation and use of alternative technologies and allow operators to create bespoke solutions to their specific site conditions, which may include use of alternative technologies, while still allowing for similar or greater emissions reductions.

*States have successfully adopted performance-based standards that have measurably improved air quality and are driving future improvements.* Commenter (2452-Hess) provides that performance-based approaches for emissions reductions have already been successfully

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<sup>50</sup> Currently, the commenter reports that they are evaluating, piloting or implementing the following emissions reduction opportunities: optimizing gas infrastructure, which includes additional compression capacity and gathering lines; installing oil coolers to stabilize oil and reduce tank gas flashing to flare; reinjecting natural gas liquids into the product line at compressor stations; replacing gas assisted flares with more efficient air assist flares; diverting compressor station blowdown from flares to station inlet; optimizing pipe heat trace design to lower power consumption; using grid electricity, which we mitigate through the purchase of Renewable Energy Credits, to power onshore drilling and completions activity; examining alternatives to wellhead flaring, such as utilizing natural gas for onsite power generation or conversion to liquified natural gas; examining purchase power options to supply Hess’ electricity needs through renewable or carbon neutral energy, thereby offsetting or eliminating our Scope 2 GHG emissions; and using advanced data analytics and machine learning to optimize fuel gas consumption.

implemented in oil and gas producing states. For example, the North Dakota Industrial Commission’s Order No. 24665, issued in 2014, established gas capture goals that imposed progressively higher capture requirements for associated gas. This requirement resulted in a rapid expansion of infrastructure and operational improvements leading to significant reductions in flared gas. In addition, they report that Colorado recently established a “Greenhouse Gas Intensity Program for the Oil and Natural Gas upstream Segment.”<sup>51</sup> This program requires operators to reduce preproduction and production emissions, with progressively more stringent intensity targets beginning in 2025. Gas capture goals and intensity-based programs like those adopted at the state level drive improvement while allowing flexibility for operators to implement appropriate solutions for their unique situations.

*Federal laws and regulations support use of performance-based approaches.* In addition to state initiatives, the commenter (2452-Hess) states that performance-based approaches to emissions reductions have been endorsed at the federal level. The bipartisan Inflation Reduction Act of 2022 (IRA) established a Methane Emissions Reduction Program (MERP) that requires the EPA to collect a “waste emissions charge” from owners or operators of certain facilities subject to 40 CFR Part 98 Subpart W (Subpart W) that exceed an applicable waste emissions threshold. For petroleum and natural gas production, the methane charge applies to emissions that exceed either “A) 0.20 percent of the natural gas sent to sale from such facility; or B) 10 metric tons of methane per million barrels of oil sent to sale from such facility, if such facility sent no natural gas to sale.”

Notably, the commenter (2452-Hess) explains that the IRA includes an exemption for an applicable facility subject to and in compliance with “methane emissions requirements pursuant to subsections (b) and (d) of section 111 [of the Clean Air Act]” if the EPA Administrator determines that such standards are in effect and compliance “will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled ‘Standards of Performance for New, Reconstructed, and Modified Sources and Emission Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review’ (86 Fed. Reg. 63110 (November 15, 2021)), if such rule had been finalized and implemented.” The IRA’s explicit connection to emissions reductions from the proposed rule that preceded the December 2022 supplemental proposal demonstrates the suitability of similar performance-based approaches in the December 2022 supplemental proposal. Specifically, the reference shows that Congress has focused on the resulting emissions reductions and not the mechanism to achieve the reductions. The commenter believes that the EPA should do the same here.

Further, the commenter (2452-Hess) states that the existing EPA regulations establish a logical framework from which to measure performance-based improvements. Subpart W provides a ready-made system for tracking and measuring emissions against prior years. Similar to the integration of Subpart W into the IRA’s MERP, the commenter suggests that the EPA could use Subpart W data to guide performance-based standards for the December 2022 supplemental proposal.

Response II-23-35: The EPA appreciates the commenter’s recommendation. However, creating the recommended framework to measure performance-based improvements is not supported by

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<sup>51</sup> See 5 C.C.R. § 1001-26(IV). 5 See 42 U.S.C. § 7436(f).

CAA sections 111(b) and 111(d), which is the basis for the NSPS OOOOb standards and EG OOOOc presumptive standards. See sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

As noted by the commenter, however, CAA section 136(c) directs the Administrator of the EPA to “impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent (CO<sub>2</sub> Eq.) of GHG emitted per year pursuant to subpart W of part 98 of title 40 (40 CFR part 98), regardless of the reporting threshold under that subpart” (hereinafter, waste emissions charge). An “applicable facility” is defined under CAA section 136(d) to include nine specific industry segments as defined in GHGRP subpart W. Pursuant to CAA section 136(g), the waste emissions charge “shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter.” See section VI.C (Methane Emissions Reduction Program) of the final rule preamble for additional discussion on the Methane Emissions Reduction Program, including the section 136(f) exemption from the waste emissions charge for applicable facilities that meet certain criteria.

## **23.10 Alternative Technical Measurement and Verification Protocols and Testing Laboratories**

### ***23.10.1 Technology Neutral Protocol to Measurement and Verification***

Comment: Commenter (2426-Veritas) notes that their approach (*i.e.*, Veritas) is a standardized, science-based, technology neutral, measurement and verification-informed methane emission measurement approach to calculating and reporting methane emissions. The commenter reports that their initiative was launched in 2021 by GTI Energy. They state that their approach provides specific technical protocols for each segment of the natural gas industry (production, gathering and boosting, processing, transmission and storage, distribution, and LNG) to measure methane emissions in a consistent, credible, and comparable way. The commenter further provides that their technology-neutral protocols formulate a comprehensive toolbox of methodologies designed to accelerate methane emissions reductions.

The commenter (2426-Veritas) reports that the first versions of the protocols are being made publicly available February 14, 2023, at: <https://veritas.gti.energy>.

The commenter (2426-Veritas) explains that the Veritas technical protocols consist of:

- *Methane Emissions Intensity:* Defines what methane intensities should look like for each segment of the natural gas supply chain.
- *Measurement:* Describes how to take measurements to inform emission inventories, by segment.
- *Reconciliation:* Reconciles emission-factor or baseline inventories with actual measurements, by segment.
- *Value Chain Summation:* Adds multiple segments to reach a total emissions intensity.

- *Assurance*: Provides guidance for verifying an emissions inventory, company documentation requirements, and third-party auditing

The commenter (2426-Veritas) asserts that Veritas is unique in that it is entirely committed to broadening access to the most effective technical processes and technologies that are currently available to reduce methane emissions, in hopes of giving industry a hands-on blueprint of how to implement methane mitigation initiatives successfully and yield credible results.

The commenter (2426-Veritas) informs that GTI Energy will publish and maintain these protocols as open-source, technical tools that can be deployed and operationalized by different stakeholders around the world.

Response II-23-36: The EPA appreciates the commenter's provided information on their standardized, science-based, technology neutral, measurement and verification-informed methane emission measurement approach to calculating and reporting methane emissions.

Development of emission inventories are outside the scope of the final rulemaking and this document.

### ***23.10.2 Biogenic Carbon Content Testing***

Comment: Commenter (2169-Beta Analytic) submitted information on developing technology for the EPA to consider with regards to the proposed approval process for technologies for alternative periodic screening. The commenter believes that, particularly important is that while existing methane detection technologies only identify the presence of emissions, the method they provide for EPA's consideration would have the potential to identify their source through isotopic characterization. Specifically, their recommendation is that the EPA consider the potential for biogenic carbon content testing using isotopic concentrations to play a role in methane emissions detection and create a regulatory pathway for its use.

The commenter (2169-Beta Analytic) notes that their testing laboratory was among the originators of the American Society for Testing and Materials (ASTM) D6866 biobased/biogenic testing standard using carbon-14 to distinguish renewable carbon sources from petroleum sources in solids, liquids, and gases. They inform that renewable testing started in 2003 at the request of U.S. Department of Agriculture (USDA) representatives who were interested in Beta's Carbon-14 capabilities for their USDA BioPreferred® Program ([www.biopreferred.gov](http://www.biopreferred.gov)). Carbon-14 third party testing is now standardized in a wide range of international standards including ASTM D6866, European Committee for Standardization (CEN) 16137, European Standard (EN) 16640, ISO 16620, International Organization for Standardization (ISO) 19984, British Standard (BS) EN ISO 21644:2021, ISO 13833 and EN 16785. The commenter reports that they continue to be involved in ASTM D6866 revisions.

The commenter (2169-Beta Analytic) recommends Carbon-14 testing as the preferred method for determining the biogenic carbon content of methane emissions under the EPA's proposal to reduce pollution from oil and natural gas operations. Their recommendations to the EPA

following this proposal to reduce pollution from the oil and natural gas industry to fight the climate crisis and protect public health are as follows:

- (1) Consider the potential for isotopic identification to play a key role in methane tracking and remediation in the near future based on Beta Analytics' six-month Phase I SBIR Grant timeline, with the intention to apply for a two-year extension (Phase II) thereafter.
- (2) Expand upon the proposed survey matrices for alternative periodic screening to incorporate isotopic concentration testing, as Beta's methodology will be fundamentally different from existing processes that use sample concentration practices.
- (3) Include baseline testing of atmospheric gases so that isotopic changes over time can be determined, differentiated, and remediation strategies identified.
- (4) Include periodic isotopic performance testing of oil and NG emissions that is conducted by an ISO/International Electrotechnical Commission (IEC) 17025:2017 accredited testing laboratory.
- (5) Research how emissions reduction equivalency achieved with isotopic concentration testing could be compared to OGI.

The commenter (2169-Beta Analytic) adds that isotopic characterization of methane emissions may lead to new remediation strategies to combat increasing global methane concentration. The commenter believes that ASTM D6866 testing is crucial for the EPA's goal of fighting the climate crisis and protecting public health by reducing pollution from major methane emitters, oil and natural gas.

Commenter (2169-Beta Analytic) emphasizes support for Carbon-14 measurements done by commercial third-party testing as being robust, consistent, and with quantifiable accuracy/precision of the carbon-14 amount under ASTM D6866 method B. They provide that EN 16785 is the only standard that allows a variant of the Mass Balance (MB) method of 'carbon counting' under EN 16785-2. EN 16785-1 requires that the biocarbon fraction be determined by the carbon-14 method.

In ASTM D6866 method B, the commenter (2169-Beta Analytic) explains that the carbon-14 result is provided as a single numerical result of carbon-14 activity, with graphical representation that is easily understood by regulators, policy makers, corporate officers, and more importantly, the public. The commenter believes that the overwhelming advantage of carbon-14 is that it is an independent and standardized laboratory measurement of any carbon containing substance that produces highly accurate and precise values. In that regard, they add that it can stand alone as a quantitative indicator of the presence of renewable vs. petroleum feedstocks. When carbon-14 test results are challenged, the commenter explains that samples can be rapidly remeasured to verify the original reported values (unlike mass balance).

The commenter (2169-Beta Analytic) suggests that MB lacks robust and transparent methods of validation for mixing, balancing, and tracking carbon that translates to a real credit-based system. The U.S. Department of Agriculture BioPreferred program discovered early on that misbranding could undermine not only regulatory, but more importantly, consumer confidence, which was also pointed out in a 2021 panel on the assessment of mass balancing accounting method for polymers working by the National Institute of Standards and Technology (NIST). They also determined that some brand owners might find the MB approach too complex. When the 2021 NIST panel was asked in a single work to describe mass balancing accounting for polymers, the six descriptive words were: complex, critical, necessary, confusing, ugly, and certifiable. [Note: Additional support for the use of Carbon-14 measurements over MB methods is provided in the commenter's letter.]

The commenter (2169-Beta Analytic) concludes by noting that, to ensure the highest level of quality, laboratories performing testing under the USDA BioPreferred Program by ASTM D6866, require that the laboratory be accredited to ISO/IEC 17025:2017 testing standard. The commenter states that this accreditation is unbiased, third party verified, and annually audited by the accreditation body. According to the commenter, it is unique to laboratories that not only have a quality management program that is conformant to the ISO 9001:2008 standard, but more importantly, have demonstrated to an outside third-party laboratory accreditation body that they have the technical competency necessary to consistently deliver technically valid test results. ISO/IEC 17025:2017 accredited testing laboratory results are universally recognized and accepted by all governmental, regulatory bodies and laboratories.

Response II-23-37: The EPA appreciates the commenter's provided information on biogenic carbon content testing conducted at their laboratory.

### ***23.10.3 Synergistic Measurement Requirements Across EPA's Regulatory Program***

Comment: Commenter (2350-CEI) recommends that the EPA consider synergistic measurement requirements for operators to comply with across the EPA's regulatory program. The commenter notes that several EPA regulatory initiatives related to the oil and natural gas sector are in development in addition to this proposed rulemaking, including the requirements for the GHGRP under Subpart W and the implementation of the IRA methane fee and MERP. The commenter explains that evolving measurement technologies offer the EPA the opportunity to harmonize the methodologies used to satisfy both GHGRP and NSPS OOOO requirements, along with upcoming requirements for the implementation of the methane fee. Approved technologies, according to the commenter, and the conditions around their deployment such as survey frequency and probability of detection, should be consistent between the different regulatory programs.

The commenter (2350-CEI) provides that creating a like-to-like comparison between facilities or operators in an evolving environment of measurement technologies is challenging. They explain that measurements from advanced technologies must be carefully interpreted so that their spatial and temporal scales align with those of the reporting program. Different technologies have different spatial and temporal characteristics, along with varying probabilities of detection and uncertainty. Therefore, qualified experts familiar with how to accurately measure and quantify

GHG emissions from oil and gas facilities are essential when developing empirical data. The commenter recommends that the EPA utilize modeling tools and public empirical datasets compiled by credible third-party experts.

The commenter (2350-CEI) states that they are a founding sponsor of one such organization: the Energy Emissions Modeling and Data Lab<sup>52</sup> (EEMDL), which was launched in January 2023 by the University of Texas at Austin in partnership with Colorado State University and the Colorado School of Mines. The commenter provides that EEMDL is developing transparent models and datasets for accurate GHG emissions accounting across global oil and gas supply chains. EEMDL has three strategic approaches: (1) develop community models and tools for GHG emissions assessments, (2) make timely and high-resolution emissions datasets that are publicly available, and (3) create educational and training materials to enable the widespread use of EEMDL's models and data. The commenter suggests that modeling tools, such as those EEMDL is developing, may help the EPA account for the different spatial and temporal scales of available measurement technologies, and support operators as they prepare annual GHGRP inventories based on empirical data. The commenter believes that EEMDL's datasets may be robust enough to help the EPA conduct a robustness check on its bottom-up inventory, and even be used to prepare dynamic, empirical emission factors based on the previous year's measurement data from industry.

Response II-23-38: While not within the scope of this rulemaking, the EPA appreciates the commenter's provided information on their recommendation that the EPA consider synergistic measurement requirements for operators to comply with across the EPA's regulatory program.

### **23.11 Low-Emissions Design/Methane Destruction Methods**

Comment: Commenter (2213-Occidental) appreciates EPA adopting an equipment-based approach for determining the fugitive emissions monitoring frequency in lieu of the baseline emissions approach. The commenter notes that this framework incentivizes low-emission designs and aligns with their company's low-emissions designs for new oil and gas facilities.

The commenter (2213-Occidental) provides that their designs for new oil and gas facilities in the Permian and DJ Basins use pipelines instead of trucks to transport oil to a central processing facility, eliminating the need for oil storage near wells. According to the commenter, these tankless designs reduce both the volume of oil and gas on-site and the amount of potentially emitting equipment. They also report that they use instrument air to operate the pneumatic devices at these facilities. The commenter reports that these innovative facility designs decrease our environmental footprint by reducing emissions, dust, noise, and truck traffic.

Complementing their low-emissions design, the commenter (2213-Occidental) reports that these facilities are also less susceptible to leaks and fugitive emissions due to automation and measurement systems. They state that their automation and measurement systems are used in many locations to continuously monitor the performance of their wells and facilities. The commenter adds that it monitors key processes, process variables (such as temperature, pressure,

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<sup>52</sup> Information regarding EEMDL can be accessed at <https://www.eemdl.utexas.edu/>.

and flow rate), and equipment components in real-time or near-time that alert our operators to a potential issue, allowing them to take swift action. They provide that automation and measurement systems also enable them to trend equipment performance and plan for maintenance and replacement.

Response II-23-39: The EPA commends the commenter for their implementation of low-emissions designs that are less susceptible to leaks and fugitive emissions due to automation and measurement systems. The EPA also agrees that finalizing an equipment-based approach for fugitives that is based on the specific equipment that is located at the well site does complement their low-emissions design approach.

Comment: Commenter (2184-PSR Climate Ambassador) states that because methane capture technologies are most often faulty and imperfect, [it is] best for the EPA to give technical guidance to corporations planning to build new gas transmission pipelines or LNG facilities to create new business plans to create renewable energy sources instead. The commenter requests that the EPA perfect their public relations to guide all new energy infrastructure and new facilities on how to use renewable energy sources.

Response II-23-40: Providing technical guidance to corporations planning to build new gas transmission pipelines or LNG facilities to create new business plans to create renewable energy sources instead is not within the scope of this rulemaking; as such, no response is required.

Comment: Commenter (2407-MA) requests the EPA take the potential emergence of methane removal methods into account by indicating in its current rulemaking that it will assist in their research and development and review the results frequently, with a view toward adding approved methane emissions destruction methods to the list of Best Systems of Emissions Reduction (BSER) (the standard required under CAA section 111 as soon as possible). The commenter provides a list of current and proposed research projects for methane removal technologies in an attachment to their comment letter (e.g., zeolites and catalysis, photocatalysis, generation of Cl atoms (one-carbon molecules), generation of hydroxyl radicals by photolysis and generation of ultraviolet (UV)-B/UV-C, and oxygen atoms, methanotroph-based methane removal or mitigation).

Response II-23-41: The EPA appreciates the information the commenter provided on current and proposed research projects for methane removal technologies.

## **23.12 Units of Measure**

Comment: Several commenters (2168- INOGA, 2172 KOGA, 2200-NuEO, 2257-MOGA and 2211-LER) state that that the EPA should use the language of the industry to clearly communicate objects and standards. Specifically, the commenters note the mixed use of imperial units (i.e., 6 tons per year and metric units (kilograms (kg)/hour(hr))).

Commenter (2257-MOGA) notes their constituents commented on the lack of understanding of kg/hr and requested the EPA use scf/hr and ppm which is the standard language and vernacular of the industry. The commenters state that the EPA should standardize on either imperial units or



metric units. According to commenters, mixing the units between imperial and metric is going to create errors for operators that do not have the capability to convert between the two. If the EPA desires to use metric units, it is recommended that a calculator should be available, when the final regulation is released, to be able to convert between imperial and metric units.

Response II-23-42: The EPA acknowledges the commenter's request. The EPA generally uses imperial and not metric units, but often has to convert supporting data that is in metric units.

### **23.13 NSPS OOOO and NSPS OOOOa Changes**

Comment: Commenter (2326-AXPC) remains supportive of EPA, in keeping the efficiencies in 40 CFR subpart OOOOa, that EPA intends to retain, as reflected in the December 2022 supplemental proposal. The commenter states that these efficiencies reduce unnecessary burden without negative environmental impacts – thus increasing the cost-effectiveness of the NSPS OOOOa rulemaking.

Response II-23-43: These comments are supportive comments; as such, no response is required.

### **23.14 Administrative Record – Early Input on Methane Regulation**

Comment: Commenter (2355-CEC) requests that all contents of regulatory docket ID No. EPA-HQ-OAR-2021-0295 should be part of the record for docket ID No. EPA-HQ-OAR-2021-0317. The commenter notes that the EPA opened a docket for stakeholders to submit early input on issues informing the original proposal, and that docket was assigned Docket ID No. EPA-HQ-OAR-2021-0295. According to the original proposal, the contents of Docket ID No. EPA-HQ-OAR-2021-0295 are not automatically part of the original proposal rulemaking record, and for information submitted to that docket to be considered in the Original Proposal and Supplemental Proposal rulemaking, it must be resubmitted to Docket ID No. EPA-HQ-OAR-2021-0317. That approach risks excluding information and material that informed EPA's Proposal from the administrative record. Instead, the commenter believes that all contents of Docket ID No. EPA-HQ-OAR-2021-0295 should be automatically incorporated into and considered part of the rulemaking docket for the November 2021 original proposal and December 2022 supplemental proposal, Docket ID No. EPA-HQ-OAR-2021-0317.

Response II-23-44: The EPA has included in the docket for this action all information upon which the Administrator relied for the proposed and final actions, as well as all comments received on the proposed rulemakings, consistent with the requirements of CAA section 307(d).

With regards to the request that the contents of non-rulemaking Docket ID No. EPA-HQ-OAR-2021-0295 be included in the rulemaking Docket ID No. EPA-HQ-OAR-2021-0317, the EPA has not granted that request. The EPA opened the non-rulemaking docket (Docket ID No. EPA-HQ-OAR-2021-0295) for public input on the Agency's efforts to reduce emissions of methane and other air pollutants from new and existing sources in the oil and natural gas sector in order to further the Administration's policies as described in Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." The goal of this non-rulemaking docket and other public engagement efforts was to gather perspectives from

a broad group of stakeholders for the oil and natural gas sector, including individuals and communities that experience disproportionate adverse health and environmental impacts as a result of oil and natural gas operations.

### **23.15 TSD Citation — Cost Impacts of Revising Control Device Efficiency Standards to 98 Percent**

Comment: Commenter (2362-EIP et al) notes that Chapter 7 of the TSD includes a link to the “...updated chapters and spreadsheets for the planned Seventh Edition...” of EPA’s Air Pollution Cost Control Manual. However, the commenter states that the link is broken, which means the document cited is not available to the public.

Response II-23-45: The EPA Air Pollution Control Cost Manual, upon a simple search at: <https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual>. There was a missing hyphen between cost and analysis. See also Docket ID EPA-HQ-OAR-2021-0317-0050 (U.S. Environmental Protection Agency (EPA). 2002. EPA Air Pollution Control Cost Manual. Sixth Edition. EPA/452/B-02-001. Updated Chapters 1 and 2. 2017-2019). The November 2021 Proposal Technical Support Document (TSD) Air Pollution Control Cost Estimation Spreadsheets for Elevated Flares (April 2019) can be found at Docket ID EPA-HQ-OAR-2021-0317-0039. The December 2022 Supplemental Proposal TSD (EPA-HQ-OAR-2021-0317-1578), Chapter 7, Air Pollution Control Cost Estimation EPA Flare Cost Excel Sheets can be found at Docket ID EPA-HQ-OAR-2021-0317-1621.

### **23.16 Other CAA Program Considerations**

#### ***23.16.1 Regulation of Existing Sources in Metropolitan Areas Under CAA Section 112***

Comment: Commenter (2307-Climate Action et al) encourages EPA to regulate existing oil and gas sources using CAA section 112 in metropolitan areas. The commenter believes that that will allow much prompter control requirements, without the long spans allowed for states and tribes to submit plans, and another period during which EPA reviews such plans as well as eliminates the ability of states or tribes to exempt certain facilities.

Response II-23-46: This comment regarding the regulation of existing oil and gas sources using CAA section 112 is outside the scope of this rulemaking; as such, no response is required.

#### ***23.16.2 Consistency with International Methane Emission Reduction Programs***

Comment: Commenter (2396-Shell) provides technical input on the EPA’s methane performance standards and related regulatory requirements in the proposed rule through various associations and groups of which the commenter and its affiliates across the globe hold memberships. As a result, the focus of their comments here is on several overarching elements that they believe should be included in the EPA’s methane regulatory program being developed under CAA section 111. The commenter suggests that the EPA’s full development and inclusion of the elements they outline below is necessary to ensure proper alignment of the U.S. regulatory

framework with methane regulatory programs of other countries, including those countries within the European Union. In particular, the commenter asserts that this alignment is critically important for demonstrating regulatory equivalence between the U.S. and the European Union (as well as other countries) – which, in turn, can best support and facilitate the efficient flow of LNG exports from the U.S. to those other countries.

The commenter (2396-Shell) provides key background information that informs their position on how proper alignment of the EPA’s methane regulatory framework can best be achieved with the ambitious methane regulatory programs being established by other countries. In particular, their comments briefly discuss global trends on LNG trading and relevant natural gas regulatory developments in the European Union that should inform the EPA’s development of the U.S. methane regulatory program under section 111 of the CAA. A review of these relevant international trends and regulatory developments is followed by a discussion of the three key elements that the EPA should include in the U.S. methane regulatory program to promote efficient flow of LNG exports from the U.S. to the European Union and other countries. As discussed below, these key regulatory elements include the establishment of—

- Rigorous performance standards that strive to achieve an ambitious and stringent methane intensity performance standard (such as an intensity level in the range of 0.20 percent as determined based on best available measurement data) for the upstream segments of the natural gas supply chain;
- Robust monitoring, reporting and verification (MRV) protocols aligned with the OGMP 2.0; and
- Flexible implementation framework that allows for the conversion of the EPA’s final methane performance standards for each upstream segment of the supply chain into an overall methane intensity standard.

*Global trends on LNG trading and recent regulatory developments in the European Union.* As one of the world’s largest global traders in LNG, the commenter (2396-Shell) recognizes that how the European Union regulates methane emissions from upstream natural gas operations has implications for the workability of the global market. According to the commenter, these implications are potentially of great importance to U.S. LNG exports and U.S. natural gas producers that sell LNG for export. Notably, global LNG demand continues to grow each year (even during the outbreak of the covid pandemic) and is projected to increase from 360 million tons per year in 2020 to 700 million tons per year by 2040. Furthermore, the commenter notes that the U.S. is the world’s fastest growing LNG exporter with ten new LNG export projects coming online in 2020 and with total LNG exports projected to increase by 188 percent from 50 million tons per year in 2020 to 144 million tons per year in 2040.

The commenter (2396-Shell) provides that the European Union is a key market for import of natural gas from the U.S. and other countries. As a result, the European Union’s decisions on methane regulations (specifically the potential adoption of methane intensity standard) could have significant ramifications for U.S. exports of natural gas into the European Union.

The commenter (2396-Shell) notes that the European Commission recently issued last December its legislative proposal to reduce methane emissions from the energy sector. Although not yet

finalized, that legislative proposal includes a prerogative for the Commission to amend the legislative proposals to impose more stringent measures on natural gas importers by 2025 once better global methane emission data are available, including targets. The European Parliament has been calling for the introduction of such targets and is expected to request their inclusion in the final legislation prior to 2025. For example, an intensity performance standard of 0.20 percent could apply to the upstream segment of the natural gas supply chain from wellhead to point of sale.

Given that the European Union imports from the U.S. and other countries over 80 percent of its natural gas, the commenter (2396-Shell) reports that it is anticipated that if the legislation is amended to introduce a methane intensity standard for all gas consumed in the EU, the European Union will apply such a standard to natural gas (including LNG) that is imported from all foreign countries. To assure that the imported natural gas meets this methane intensity standard, the importers of the natural gas may be subject to a proportional financial penalty for the portion of their natural gas volumes that exceeds the applicable methane intensity standard. This financial penalty could be imposed as a methane fee or other GHG-related tax or fee. In addition, according to the current legislative proposal, the European Union member states are mandated to impose a penalty on natural gas imported from those countries without a robust MRV system in place. The commenter states that the penalty can be based on an assigned default emission intensity value that conservatively accounts for the potential methane emissions attributable to the production, processing, and shipment of that imported natural gas.

By contrast, the commenter (2396-Shell) explains that no financial penalties are likely to be imposed on natural gas imported from those countries that have methane regulations that are at least equivalent to the methane intensity standards and MRV protocols to be established by the European Union. In such cases, oil and gas producers, LNG traders, and shippers would not have to add another layer of verification to prove that their natural gas meets the European Union intensity standard. Without such equivalence – if the European Union proceeds with an emissions intensity standard – demonstrating compliance with that standard for upstream emissions could potentially put U.S. LNG exports at a competitive disadvantage because the only possible way to avoid financial penalties would be through costly and potentially unworkable added MRV schemes that could require tracing natural gas molecules from individual producers along complex natural gas delivery chains.

*EPA's proposed NSPS OOOOb and EG OOOOc methane control requirements.* Commenter (2396-Shell) believes that the proposed methane control requirements for new and existing oil and natural gas sources generally reflect best available control measures that are generally aligned with any methane intensity target considered by the European Union in the future for the upstream segment of the natural gas supply chain in the U.S.

*Robust MRV protocols modeled after OGMP 2.0 for demonstrating compliance and determining methane emission intensity across the natural gas supply chain.* The commenter (2396-Shell) believes that the regulatory framework authorized under CAA provides the EPA and states with considerable latitude to establish credible and reliable protocols for determining compliance with methane intensity standards. One such option is OGMP 2.0, which establishes a greatly improved set of MRV protocols that have been under development since 2019 by the United

Nations Environment Program (UNEP) and the Climate and Clean Air Coalition (CCAC) in partnership with the European Union Commission, the Environmental Defense Fund, and major industry players. The commenter explains that these MRV protocols focus on establishing best-practices for quantifying methane emissions from all segments of the oil and gas sector where material quantities of methane emissions can be released. OGMP 2.0 effectively increases the accuracy and granularity of methane emission monitoring, reporting, and verification for oil and gas assets.

In the recently proposed methane legislation, the commenter (2396-Shell) notes that the European Union uses the OGMP 2.0 as the basis for its mandatory MRV protocols under methane regulatory program that it now has under development. The commenter believes that OGMP 2.0 sets a necessary new standard for credible and transparent methane emissions reporting, while recognizing the outstanding technological, commercial, and cost challenges to improved emissions reporting. In the current legislative proposal, these MRV protocols would likely also apply to all imports of natural gas into the European Union, including LNG and pipeline natural gas imported from other countries. Adoption of the OGMP2.0 protocols by natural gas/LNG exporters into the European Union and natural gas producers in the country of origin, satisfies MRV data transparency requirements in the European Union methane legislation.

For these reasons, the commenter (2396-Shell) urges the EPA to develop robust MRV protocols for demonstrating compliance with the methane emissions standards and determining methane emission intensity across the natural gas value chain. In so doing, the EPA should work to ensure that MRV protocols being developed for the U.S. regulatory program are fully consistent and generally equivalent to the version of OGMP 2.0 now being developed for use in the European Union. This equivalence will provide a simple mechanism for demonstrating that LNG from the U.S. meets the performance standards that could be established in the future for importing LNG into the European Union.

*Methodology for converting performance standards into methane emission intensity standards.*

A third and final element put forth by the commenter (2396-Shell) is the development of a flexible implementation framework that allows for the conversion of the EPA's final methane performance standards for each affected facility and emitting activity into a methane intensity standard for all segments of oil and natural gas source category. The commenter explains that intensity targets are an effective means of managing methane emissions in the upstream natural gas supply chain and once applied to each segment of the natural gas supply chain, have the advantage of stimulating methane emissions reductions in every segment of the chain. Instead of just focusing on only certain specific types of sources for achieving the mandated methane reductions, an intensity standard would provide the most flexible and efficient way for companies to achieve methane reductions. According to the commenter, this approach will ensure all methane sources are managed and allow companies to focus its control efforts on those sources that are most impactful and effective way to reduce methane emissions.

Furthermore, the commenter (2396-Shell) believes that the establishment of an intensity standard could greatly simplify the process for demonstrating the regulatory equivalence of LNG imported from the U.S. into the European Union. The commenter asserts that the best way to

position U.S. gas exports to the European Union is based on regulatory equivalence between the trading blocks. This eliminates the formidable technical challenges with tracing gas molecules from individual producers along complex gas delivery chains. According to the commenter, such a framework for demonstrating accommodate equivalency could help to preserve U.S. competitiveness and export opportunity.

The commenter (2396-Shell) provides a regulatory analysis in Appendix B<sup>53</sup> of their comment letter that includes an explanation of the legal authority and discretion accorded to the EPA and states for implementing the methane performance standards established under section 111 of the CAA. As discussed in Appendix B of their comment letter, they believe that this authority allows for the conversion and implementation of methane performance standards into equivalent methane intensity standards.

Response II-23-47: Similar comments were provided by this commenter on the November 2021 Proposal, see Volume I, Chapter 23 (Miscellaneous Other Comments), subsection 23.11 (Other Recommendations for Reducing Impacts from Methane Emissions), Response I-23-58 for response to this comment.

### ***23.16.3 Presumptive Minimum Fee Program Required Under Title V of the CAA***

Comment: Commenter (2222-WDNR) recommends that EPA review the assumptions (established and unchanged since 1993) on which the current presumptive minimum fee program required under Title V of the CAA is based, given the changes over time to the emissions profiles of regulated sources. The commenter asserts that the review needs to include an analysis of the reduction in actual emissions at Part 70 sources even as the complexity of work and the number federal requirements has increased.

Response II-23-48: The current presumptive minimum fee program required under title V of the CAA is out of scope of this rulemaking; as such, no response is required.

Comment: Commenter (3380-Private Citizen) asserts that Michigan's Oil and Gas Industry does not warrant the new regulations on existing emission sources that are covered under the EPA's proposed EG OOOOc. The commenter provides that, during 2021 Michigan (1) had 15,748 active oil and gas wells (10,362 gas and 5,386 oil); (2) total annual production was 4,400,000 barrels oil and 71,800,000 thousand cubic feet (Mcf) natural gas; (3) the average production for oil wells was 2.24 barrels of oil per day (BOPD) and for gas wells 20 thousand cubic feet per day (Mcf); and (4) there were only 25 producing properties making over 100 BOPD and 32 gas production properties delivering over 1,000 Mcfd. The commenter contends that assessing fees for natural gas emissions on pumping oil wells that are only active for a couple hours per day is excessive and fees associated would likely make a significant number of wells uneconomic. Likewise for gas wells, a significant number are operated on vacuum compression, so emissions are not feasible on wellheads and gathering lines. The commenter notes that they understand the need to reduce natural gas emissions but they believe that assessing fees must focus on large

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<sup>53</sup> Appendix B of the commenter's letter is entitled "EPA and State Authority to Convert EPA'S Final Methane Performance Standards to Intensity Standards", 3 pages.

emitters. Lastly, the commenter suggests that EPA should have production rate minimums similar to marginal wells such as a minimum of 10 BOPD or of 50 Mcfd.

Response II-23-49: In response to the commenter stating that the Michigan Oil and Gas Industry does not warrant new regulations on existing emissions sources that are covered under the EPA's proposed EG OOOOc, see section VIII.C (Establishing Standards of Performance in State Plans) of the final rule preamble for a discussion of the requirements under section 111(d) that a state plan's standards of performance reflect the presumptive standard.

The commenter states that they believe that fees should be focused on large emitters and recommended that production rate minimums be applied where only rates above the production rate would be assessed for fees. The current fee program required under title V of the CAA (which we believe that the commenter is referring to) is out of scope of this rulemaking; as such, no response is required.

If, however, the commenter is referring to a waste emissions charge via the implementation of CAA section 136, that it was outside of the scope of this rulemaking. CAA section 136(c) directs the Administrator of the EPA to "impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent (CO<sub>2</sub> Eq.) of GHG emitted per year pursuant to subpart W of part 98 of title 40 (40 CFR part 98), regardless of the reporting threshold under that subpart" (hereinafter, waste emissions charge). An "applicable facility" is defined under CAA section 136(d) to include nine specific industry segments as defined in GHGRP subpart W. Pursuant to CAA section 136(g), the waste emissions charge "shall be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter." See section VI.C (Methane Emissions Reduction Program) of the final rule preamble for additional discussion on the Methane Emissions Reduction Program, including the section 136(f) exemption from the waste emissions charge for applicable facilities that meet certain criteria.

## **23.17 Inconsistency with Other Federal Requirements**

Comment: Commenter (2257-MOGA) states that several small-entity oil and gas producers in the State of Michigan have asked the EPA why the Mineral Leasing Act and updates to the BLM regulations highlight waste prevention including, limiting gas flaring, leak detection, reduced venting and gas capture when Michigan's small business operators are being asked to open tank hatches daily to "strap" the oil level in each tank containing oil produced from BLM property. For those readers who are not lease operators, geologists and/or engineers engaged in the daily production of oil and gas, they report that when a thief hatch is open, all working, standing, and breathing losses (including methane and VOCs) are vented from the system. The commenter understands the frustration of Michigan's producers and the great financial and impractical operational burden additional regulations will place on already diminishing production, but BLM required daily venting of methane and VOCs from the entire tank system and vapor recovery piping to ascertain production within ¼ of an inch, while simultaneously imposing leak detection of possible leaks is hypocritical and completely invalidates the cost benefit analysis of methane and VOC emissions reduction.

Response II-23-50: This comment on BLM requirements is outside the scope of this rulemaking; as such, no response is required.

Comment: Commenter (2257-MOGA) questions EPA’s narrative and rhetoric regarding the dangers of methane to “climate change” when simultaneously proposing regulations regarding methane sources that are not linear to the EPA narrative of the dangers of methane to human health and the environment. As noted in their January 17, 2023, letter requesting a public comment extension from 20 state Attorney Generals, the EPA had published concurrent revisions to both the December 6, 2022, proposed NSPS OOOO(b) and EG OOOO(c) and “Waters of the United States”. The commenter notes that the EPA’s press release on December 30, 2022, indicated that the final “Waters of the United States” was necessary to “protect people’s health” by expanding the definition of “Water of the United States” to “upstream water resources”. The commenter questions the EPA’s logic regarding expanding protection of the “Waters of the United States” and associated wetlands while simultaneously explaining the harmful effects of methane on climate change.

The commenter (2257-MOGA) reports that wetlands emit almost twice the amount of methane to the environment than estimated oil and natural gas production emissions. Many of the commenter’s constituents question whether it is appropriate for the EPA to propose regulations for the protection of wetlands likely resulting in the creation and protection of additional wetlands when the EPA has gone to great lengths to explain the detrimental effects of methane on human health and the environment. The commenter’s members are concerned with this logic and feel the EPA is “picking and choosing” logic and data to support an anti-oil and gas narrative.

Response II-23-51: See discussions in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for the Final Rule Scope) of the final rule preamble for the basis and scope of the final NSPS OOOOb and EG OOOOc rules.

With regards to the final “Waters of the United States” definition, this comment is out of scope of this rulemaking, as such, no response is required.

Comment: Commenter (2293-Private Citizen) states that in Utah, the proposed Uinta Basin Railway (UBR) would facilitate expansion of oil extraction in an area already non-compliant with CAA pollution standards. The commenter explains that the UBR’s anticipated 3-4-fold increase of oil production, transportation, and ultimately combustion would increase—not decrease—U.S. GHG emissions locally, regionally, and globally. Nevertheless, the commenter states that the U.S. Surface Transportation Board (STB) and the U.S. Forest Service have green-lighted the 85-mile long UBR, granting the permit and right of way requested by district and interlocal agency officials aligned with the fossil fuel industries.

The commenter (2293-Private Citizen) adds that the STB and Forest Service environmental reviews failed to comprehensively address VOC-and methane- generated ozone formation and related health impacts in the Uinta Basin and downwind in Colorado. They report that they failed to address likely SC-GHG impacts to the region and beyond. According to the commenter, the STB and the Forest Service disingenuously pretended that the only impacts needing focus were



those directly occurring within the immediate UBR project area. [Note that Uinta is sometimes spelled Uintah.]

Additionally, the commenter (2293-Private Citizen) provides that the Uinta Basin oil industry has a second proposed project in-the-works to get more waxy crude oil transported to domestic and foreign markets. The U.S. BLM will have to decide whether to permit construction of what's been dubbed a "hydrocarbon highway" through Gate Canyon, so that a fleet of oil tankers can proceed through Nine Mile Canyon to the Union Pacific railhead. Nine Mile Canyon is a world-class prehistoric art and artifacts gallery. With BLM approval for Gate Canyon and the STB-Forest Service go-aheads for UBR, Uinta Basin oil and gas businesses would have three transit corridors to expand oil production and exports. The commenter asks how this "squares" with President Biden's COP27 pledge?

According to a 2021 University of Utah report in the journal *Nature*, the commenter (2293-Private Citizen) reports that 6-8 percent of methane extracted in the Uinta Basin is escaping into the atmosphere.<sup>54</sup> Methane is a precursor to tropospheric (ground level) ozone formation and is a potent climate change gas. The commenter notes that a Univ. of Utah report notes that uncaptured Uinta Basin methane emissions are among the highest in the U.S. The commenter includes graphic evidence of how bad the ozone pollution has been recently in Duchesne County, located in the Uinta Basin. The Basin is currently home to over 10,000 wells...a number expected to increase if the UBR and the hydrocarbon highway are constructed.

Response II-23-52: The Uinta Basin Railway (UBR) expansion of oil extraction approved by the U.S. Surface Transportation Board (STB) and the U.S. Forest Service and BLM approval for Gate Canyon is out of scope of this rulemaking; as such, no response is required.

## **23.18 Misunderstanding of GHG Physics**

Comment: Commenter (2300-SEPP) argues EPA's regulations against GHGs demonstrate the ignorance of physical science by the Federal government. The commenter states that starting in 1859, using early spectroscopy, John Tyndall developed a series of laboratory experiments to explain why the earth was sufficiently warm to sustain complex life, given its distance from the sun. He realized that certain atmospheric gases are transparent to incoming radiation from the sun but inhibit the loss of heat. Tyndall named these gases GHGs and recognized that by far the most important one is water vapor.

Commenter (2300-SEPP) states that in effort to explain other issues such as Ice Ages, some scientists misinterpreted the work of Tyndall including the noted chemist Svante Arrhenius who, in 1896, proposed a relationship between carbon dioxide concentrations and temperatures that the commenter contends were false. The commenter notes that the EPA has used this paper to defend its views on the warming influence of carbon dioxide and other GHGs even though Arrhenius refuted his earlier work in 1906.

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<sup>54</sup> [www.nature.com/articles/s41598-021-01721-5](https://www.nature.com/articles/s41598-021-01721-5).

The commenter (2300-SEPP) reports that we now have over 150 years of laboratory experiments backed by over 50 years of atmospheric observations that show the characteristics of GHGs. What the EPA does not recognize is:

- For an average temperature of 296 K (22.85C, 73.1F) the earth emits infrared radiation in the range from 0 to about 2000 nanometers, as defined by Planck's law. Earth's strongest emissions are from about 400 to 800 nanometers. Calculations of GHG interference with other electromagnetic radiation beyond 2000 nanometers have little meaning.
- GHGs interfere with infrared radiation in specific wavelengths (frequencies). For example, carbon dioxide interferes strongly with infrared radiation in the 500 to 800 nanometer range.
- The warming effect is non-linear. No simple mathematical ratio can correctly compare two GHGs such as carbon dioxide and methane.
- The greenhouse effect is self-limiting. For example, the influence of both carbon dioxide and water vapor are logarithmic, meaning that the rate of temperature increase declines as the concentration increases.
- Both carbon dioxide and water vapor are strongly saturated. Just like a sponge saturated with water, the carbon dioxide and water vapor cannot interfere with significantly more infrared energy emitted by the earth in that wavelength (frequency), and it passes through to space. Adding more of that GHG has little effect on temperatures.
- The interference capability of a specific GHG may be virtually eliminated by another GHG. For example, the wavelengths (frequencies) in which methane interferes with infrared radiation are already covered by water vapor, the dominant GHG. This joint interference renders the influence of additional methane minuscule.

Commenter (2300-SEPP) adds that the peer reviewed fifty-year old HITRAN database is based on over 150 years of laboratory measurements under ideal conditions. Atmosphere measurements of pressure and temperature from weather balloons provide the data to modify the cross-sections of laboratory measurements in calculable ways. The commenter contends that these corrections are needed to understand what is really occurring in the atmosphere, going far beyond laboratory measurements, much less speculation.

Commenter (2300-SEPP) states Atomic, Molecular, and Optical (AMO) physicists have made their careers on understanding how matter interacts with electromagnetic radiation, including infrared radiation emitted by all bodies in space, including the earth. Distinguished AMO physicists William van Wijngaarden, University of York, and William Happer, emeritus of Princeton, have used the HITRAN database to write a series of papers on the interaction of GHGs on the earth's thermal (infrared) radiation.

Commenter (2300-SEPP) concludes in so doing, these physicists have summed a wealth of physical evidence that has been ignored by the EPA and by many scientists for decades. The commenter asserts that physical evidence trumps any speculation or theories. According to the commenter, it is past time for the EPA to evaluate physical evidence, not its pet theories. Until it

has done so, the commenter believes that any of EPA's additional regulations on methane such as this one, or other GHGs are based on speculation, not science.

Response II-23-53: These comments are not within the scope of this rulemaking; as such, no response is required.

With regards to reference to article by Wijngaarden and Happer, see Volume I, Chapter 20 (Emissions and Regulatory Impacts), section 20.2.2 (Global Warming Potential (GWP) of Methane, Response I-208.

Methane is a powerful greenhouse gas. Methane is 28 times as potent as CO<sub>2</sub> over a 100-year time frame, and historical emissions of methane have contributed about a third of today's warming. Methane also contributes to increases in global tropospheric ozone levels, which damages human health and ecosystems. This action will contribute to reductions in methane emissions. See section III.A.1 (Climate change impacts from GHG emissions) of the final rule preamble for a discussion on the climate change impacts from GHG emissions.

### **23.19 Reports and Studies Submitted to EPA**

Comment: Several commenters provide studies/reports for EPA to consider. Examples of some of those studies/reports provided by commenters follow.

Commenter (3605-Private Citizen) provides a cite to a preprint paper that discusses first results from the use of measurement informed inventories at midstream facilities. The commenter suggests that in the current supplemental proposal, the proposed regulatory structure for advanced monitoring solutions appears to be driven primarily by observations from the production sector. They assert that the challenges in the midstream sector are substantially different and that the provided work provides a first look at how next-generation methods can accelerate methane mitigation:

Brown, et al., Informing methane emissions inventories using facility aerial measurements at midstream natural gas facilities;  
<https://chemrxiv.org/engage/chemrxiv/article-details/63e6b8aafcfc27a31f8ec5b9>

Another commenter (3812-Earthworks) submitted a report titled "Certified Disaster: How Project Canary & Gas Certification are Misleading Markets & Governments." Oil Change International and Earthworks. April, 2023. This report examines the gas certification market, specifically one of the current industry leaders, Project Canary. Commenter (3816-EDF) submitted a study published in Environmental Research: Health by BU, UNC, and EDF researchers examining the health impacts of U.S. oil and gas production. The study assesses the air quality and human health impacts of ozone, fine particulate matter, and nitrogen dioxide from the oil and gas sector in the U.S. in 2016 and finds that this air pollution from the sector in 2016 resulted in 7,500 excess deaths and \$77 billion in total health impacts, in addition to the climate impacts of methane emissions from the sector.

Response II-23-54: The EPA appreciates the information provided by the commenters. See also section III (Air Emissions from the Crude Oil and Natural Gas Sector and Public Health and Welfare) of the final rule preamble for a discussion of climate change impacts from GHG emissions, and the impacts from VOC and sulfur dioxide (SO<sub>2</sub>) emissions.

## **23.20 Legal Challenges**

Comment: Commenter (3848- Native Village of Kotzebue) questions the implications of the June 2022 *West Virginia vs EPA* SCOTUS decision for CAA Sections 111(b) and 111(d) standards, in addition to the related history and current status of the 2015 Clean Power Plan (CPP) and the 2019 Affordable Clean Energy (ACE) rule, how does this Supplemental Proposal substantively address the clear Congressional authority requirement now put in place by the SCOTUS?

The commenter (3848- Native Village of Kotzebue) suggests that the Agency would be better off trying to get specific language passed by Congress, instead of continuing to try and implement Agency rulemaking, with regards to issues specifically related to air pollution from major stationary sources, including the oil and gas production sector. The commenter wonders what EPA's strategy will be to successfully implement a new Rule all the way past legal challenges.

Response II-23-55: The EPA provided its statutory authority for this action in sections IV (Statutory Background and Regulatory History) and V (Legal Basis for Final Rule Scope) of the final rule preamble.

## **23.21 Out of Scope Comments**

Comment: Commenter (2382-Mappingyouuniverse) submitted a policy memo. The executive summary of the memo states that the NSPS are a part of the regulation on the methane released by the oil and gas industry with a history that traces back to the Obama administration. In order to prevent politically unstable conditions that would repeal the policy for the third time, the EPA should reconsider hiring practices and using existing staff to advance data analysis efforts and expanding administrative capacity across the agency to aid in implementation of the NSPS. Public managers should be concerned with innovation in the interest of their own workloads and the efficiency of the work between industry and environmental agencies. The policy memo provides recommendations for EPA to consider.

Response II-23-56: The commenter's policy memo and its suggestions are out of scope of this rulemaking; as such, no response is required.

Comment: Commenter (1900-Private Citizen) expresses that they understand the need to control fugitive methane leaks, in order to control climate change. However, the commenter provides that noise related to a compressor station operation is also a problem. They provide that their neighborhood of 50-80 homes fits the description of what the EPA calls as an impacted community, and they are bearing the brunt of the environmental and health effects of a compressor and noise impacts. The commenter reports that many of their neighbors (the stakeholders) do not understand how a compressor station was built with so few of them

knowing about it. Upon researching this, the commenter found that a tiny legal announcement was made in a small newspaper called the Brooke Review, in December of 2019; public comments went on through January of 2020. With the holidays, and the beginnings of COVID-19, few of us were aware that this compressor station was being built, and that it would be so noisy, and that it would flare and emit VOCs into their quiet rural neighborhood. The four major complaints the commenter has regarding the compressor station impacting their community and noise regulation include:

- There was a poor method of notification to neighborhood that a natural gas compressor would become our new neighbor before it was constructed.
- There was no explanation or rationale provided to them as to how a natural gas compressor site is selected. The site selected is 600-700 feet from established neighborhoods, but the sound and emissions carry much further.
- There is no ambient, real time air monitoring available to neighbors now that the compressor is built and online.
- Why has the regulation of noise been ignored?

Response II-23-57: Noise pollution is out of scope of this rulemaking; as such, no response is required.

## **APPENDICES**

**Standards of Performance for New, Reconstructed, and Modified  
Sources and Emissions Guidelines for Existing Sources: Response to  
Public Comments**

**86 FR 63110, November 15, 2021; 87 FR 74702, December 6, 2022**

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## Appendix A. Comments on Updated Social Cost of Greenhouse Gases Estimates

EPA identified public comment submissions received in the rule docket as containing content related to EPA's updated estimates of the social cost of greenhouse gases (SC-GHG) that were used in sensitivity analysis in the Supplemental Proposed Rule RIA and were described in the accompanying Supplementary Material for the RIA, titled *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. In this Appendix EPA provides a summary and responses to this set of public comments.

Throughout this Appendix, we refer to EPA's *External Review Draft: Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances* as the "Draft Report" and the finalized version of this report as the "Final Report". The SC-GHG estimates developed in the 2022 Draft Report are referred to as the "EPA SC-GHG estimates", and the 2021 Interim IWG recommended SC-GHG estimates are referred to as the "IWG SC-GHG estimates".

### A.1 General Comments and Use of SC-GHG Estimates in Policy Analysis

Comment: Many commenters (2349-RFF, 2398-Policy Integrity NYU, 2246-NRDC, 2194-S. Dietz et al., 2315-NYSDEC, 2397-Climate Alliance, 2433-EDF, 2208-CCES et al., 3174-Climate Science et al., 2212-UCS, 2355-Constellation, 2343-Policy Integrity NYU, 2315-NYSDEC, 2183-M. Freeman et al., 2433-EDF, 3658- PolicyInteractive, 2410-CA AG et al., 2464-Heal and Bressler, 2343-Policy Integrity NYU, 2364-CleanEarth4Kids, 3183-Climate Committee, 2231-R. Sohn, 2293-S. Holmes, 2313-M. Plevin-Foust) express overall support for EPA's Draft Report of The Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.

Several commenters (2433-EDF, 2293-S. Holmes, 2313-M. Plevin-Foust, 3658-PolicyInteractive, 2253-OCT, 2364-CleanEarth4Kids) highlight the urgent need for strong climate policies and urge EPA to take action.

Commenters (2349-RFF, 2208-CCES et al., 2398-Policy Integrity NYU, 2246-NRDC, 2343-Policy Integrity NYU, 2355-Constellation) laud EPA for developing a robust integrated assessment model and affirm that EPA followed the recommendations provided by the National Academies of Science, Engineering, and Medicine (NASEM). Commenters (2349-RFF, 2208-CCES et al., 2246-NRDC, 2397-Climate Alliance, 2315-NYDEC, 3183-Climate Committee) assert that EPA's Supplemental Proposal is consistent with the latest available science. Several commenters state that EPA's SC-GHG estimates are a significant improvement over prior values that have been used (2349-RFF, 2194-S. Dietz et al., 2397-Climate Alliance, 2208-CCES et al., 3174-Climate Science et al., 3183-Climate Committee, 2343-Policy Integrity NYU, 2398-Policy Integrity NYU).

Commenter (2349-RFF) states that "The EPA report is fully responsive to all of the NASEM's near-term recommendations" and "The EPA report's updated SC-GHG estimates are the best available SC-GHG estimates, consistent with the best available science, and should therefore replace the interim estimates reported by the Interagency Working Group in February 2021."



Commenter (2208-CCES et al.) notes that EPA’s SC-GHG estimates represent the first comprehensive update in a decade, and during that time, the scientific community has developed an improved understanding of the economics of greenhouse gas emissions. The commenter affirms that the “Draft Report comprehensively incorporates this new research and updates the social cost of greenhouse gases consistent with the best available science and economics” and “closely applies the 2017 recommendations of the National Academies of Sciences, Engineering, and Medicine.” The commenter further notes that independent valuations of the SC-GHG closely resemble the estimates from EPA’s Draft Report. The commenter notes that “Numerous foreign countries including Germany, France, and the United Kingdom also apply similar or higher valuations for the social cost of greenhouse gases” and “experts widely agree that the Working Group’s climate-damage estimates are far too low.”

Commenter (2398-PolicyIntegrity NYU) states that the Draft Report follows the roadmap provided by the National Academies of Sciences. The commenter further notes that “EPA deserves credit for developing a state-of-the-art modular integrated assessment model consistent with the suggestions of the National Academy of Sciences.” The commenter notes that EPA’s estimates are a significant improvement over the climate-damage valuations developed by the IWG and that there is a “widespread economic consensus that those Working Group values represent lower-bound estimates.”

Commenter (2246-NRDC) states that the EPA Draft Report’s update of the SC-GHG “is grounded in up-to-date science and economics” and “accurately implements necessary updates recommended by the National Academies of Sciences (NAS).”

Commenter (2194-Dietz et al.) self-identifies as academic researchers who study the social cost of greenhouse gas emissions, and from that perspective, offer congratulations to the EPA team “on their excellent work that follows many of the recent advances in climate economics.” The commenter states that the EPA Draft Report “represents a significant advance and update on earlier social cost of greenhouse gas numbers put forward by the Interagency Working Group.”

Commenter (2397-Climate Alliance) applauds EPA for its improvement over the IWG’s interim estimates, which the commenter argues are outdated and significantly underestimate the costs of climate damages. The commenter further states that EPA’s SC-GHG estimates use the latest science, appropriate discounting, and account for global damages.

Commenter (2183-M. Freeman et al.) states that the central numerical value of the social cost of carbon as well as the use of a central real social discount rate around a value of approximately 2% have strong independent support from the academic literature. The commenter cites their own independent research<sup>1,2</sup> and another study<sup>3</sup> that similarly document a higher SCC over the last decade than what is reported by the IWG interim estimates.

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<sup>1</sup> Hänsel, M.C., Drupp, M.A., Johansson, D.J., Nesje, F., Azar, C., Freeman, M.C., Groom, B. and Sterner, T., 2020. Climate economics support for the UN climate targets. *Nature Climate Change*, 10(8), pp.781-789.

<sup>2</sup> Nesje, F., Drupp, M., Freeman, M. and Groom, B., 2022. Philosophers reinforce economists' support for UN climate targets but disagree on why.

<sup>3</sup> Tol, R.S., 2021. Estimates of the social cost of carbon have increased over time. *arXiv preprint arXiv:2105.03656*.

Commenter (3174-Climate Science et al.) states that “there is little question but that the EPA social cost of carbon estimate is more representative of reality than its progenitors, given its incorporation of numerous recommendations for more accurate modeling stemming from the expert community.”

Commenter (2343-Policy Integrity NYU) states that EPA’s Draft Report “faithfully implements the roadmap laid out in 2017 by the National Academies of Sciences, and, while it represents a significant increase over the climate-damage valuations from the IWG, that increase is consistent with the widespread economic consensus, including the IWG’s own repeated recognition that its valuations are underestimates.”

Commenter (2355-Constellation) supports EPA’s work on the SC-GHG while the IWG’s work continues and highlights that underestimates of the SC-GHG would result in market disincentives for investments in cleaner energy. The commenter notes “[a]s a critical member of the IWG, EPA is an agency with technical and economic expertise that makes it well-suited to establish a social cost of greenhouse gases. EPA’s external review draft of its report on the social costs of greenhouse gases providing updated estimates based on the most recent scientific advances is a valuable resource that – together with the public comments EPA receives on it – should inform the continued work of the IWG.”

Response A-1-1: EPA thanks the commenters for their supportive comments. EPA believes that the Final Report represents the latest available science and follows the recommendations of the National Academies of Science, Engineering, and Medicine. EPA acknowledges the comments received expressing general support for EPA’s draft report and SC-GHG estimation methodology. Some of these commenters had additional recommendations for improvement in specific aspects of the estimation methodology and process; we address these in other sections of this Appendix.

Comment: Commenters (2315-NYSDEC, 2397-Climate Alliance, 2212-UCS, 2349-RFF, 2246-NRDC, 2398-Policy Integrity NYU, 3658-PolicyInteractive, 2355-Constellation) express support for EPA’s update on SC-GHG estimates and for use of these estimates in policy analysis. Commenters (2398-Policy Integrity NYU, 2246-NRDC, 2355-Constellation) express support for regular updates to the SC-GHG.

Commenter (2315-NYSDEC) “recommends that EPA issue cost values for all Greenhouse Gas emissions (GHGs) and, at the very least, for those GHGs reported to the greenhouse gas reporting program. This work will help states undertake action on these GHGs and avoid the redundant use of public funds to conduct such work.”

Commenter (2397-Climate Alliance) identifies themselves as a bipartisan coalition of governors representing 60 percent of the U.S. economy and 55 percent of the U.S. population and commits to considering the environmental and societal impacts of GHG emissions in their climate action efforts. The commenter expresses the need to account for the true cost of climate damages in policymaking. The commenter states that many members have already included estimates of the SC-GHG in their policymaking and urge EPA to ensure that the final IWG estimates are at least as strong as those presented in EPA’s Draft Report. The commenter notes that “[p]roperly

accounting for the societal costs of a changing climate is key to crafting effective state and federal policies and achieving our shared net-zero climate goals.”

Commenter (2212-UCS) commends EPA for taking “an important and necessary step” in issuing the Draft Report and incorporating its findings as a sensitivity in the supplementary RIA. The commenter notes that “while EPA makes clear that the rulemaking is not predicated on these supplemental [SC-GHG] values, the rulemaking as a whole benefits from their incorporation to provide fuller context for the potential impact of this rule.” The commenter argues that while there is an ongoing IWG process to standardize SC-GHG values, EPA should incorporate its understanding of updates in science, economics, and best practice given the potential relevance of the issue to the rulemaking.

Commenter (2246-NRDC) states that “EPA should adopt the Draft Report’s social cost of greenhouse gas (SC-GHG) estimates because they accurately reflect current scientific and economic consensus.” The commenter further argues that EPA’s modular approach makes it easier to make future updates to the SC-GHG to incorporate advances in science and economics, which the commenter recommends should occur regularly, at least every five years.

Commenter (2398-Policy Integrity NYU) added that EPA’s SC-GHG model is a “powerful tool” which has uses to policymakers beyond calculating the social costs of GHG emissions. The commenter suggests that EPA calculate the total cost of climate damages, as this would provide policymakers and the public with the scale of benefits of various global greenhouse gas emission targets and inform them about the scale of climate action necessary and/or justifiable. The commenter further argues that EPA should update its analysis at least every five years to “benefit of responding to evolving research with the need for a thorough and predictable process” as advised by the National Academy of Science.

Commenters (2355-Constellation, 2343-Policy Integrity NYU) state that it is appropriate for the Supplemental Proposal’s RIA to consider EPA’s social cost of methane sensitivity analysis, as it addresses NASEM recommendations. Commenter (2355-Constellation) “encourage[s] coordination among agencies for consistent application of a social cost of greenhouse gases to provide certainty to the regulated community, avoid confusion, and ensure that all federal regulations reflect the benefits of climate change mitigation.”

Commenter (2293-S. Holmes) states that “[a] key to meeting national goals is establishing a Social Cost of GHGs framework that is based on scientifically sound, real-world values.” The commenter expresses concern towards federal actions that have potentially undermined President Biden’s commitment to climate change action, such as the proposed Uinta Basin Railway. The commenter argues that environmental reviews conducted by other federal agencies failed to consider the SC-GHG impacts of the Uinta Basin Railway and therefore recommends that the administration standardize climate change action across federal agencies.

Response A-1-2: EPA acknowledges the comments received expressing general support for EPA’s SC-GHG estimates and the associated estimation methodology. Some of these commenters had additional recommendations for improvement in specific aspects of the estimation methodology and process; we address these in other sections of this Appendix.

Comment: Several commenters (2208-CCES et al., 2194-S. Dietz et al., 3658-PolicyInteractive, 2246-NRDC, 2313-M. Plevin-Foust, 2253-OCT, 2398-Policy Integrity NYU, 3183-Climate Committee), while providing overall support for EPA’s Report on the Social Cost of Greenhouse Gases, emphasize that EPA’s SC-GHG values remain an underestimate of the true cost of climate damages. Commenters (2208-CCES et al., 2194- S. Dietz et al., 3658-PolicyInteractive, 3183-Climate Committee) offer recommendations to improve EPA’s analysis or bolster EPA’s justification in a number of areas, discussed in more detail in the sections that follow.

Commenter (2208-CCES et al.) states that while the Draft Report is praised for incorporating the latest research and recommendations, the commenter believes that EPA still underestimates the true costs of climate change. The commenter states that EPA can expand the discussion of precedent for consideration of climate damages on a global scale to further bolster support for this geographic perspective. The commenter emphasizes that the federal government has historically viewed its climate-damage valuations as low, and the current EPA valuations are an improvement on earlier figures.

Commenter (2194-S. Dietz et al.) urges EPA to make further improvements to its SC-GHG particularly by including their recent peer-reviewed research on incorporating tipping points in SC-GHG estimation<sup>4</sup> and offer suggestions for how EPA can do this. The commenter argues that without doing so, the direct consequences for policy are an underestimate of the SC-GHG and mitigation policies that are too lax.

While expressing support for EPA’s SCC estimates, commenter (3658-PolicyInteractive) explains: the baseline for damage costs is likely overly conservative due to omitted damages; there is increased urgency to find policy solutions for the breakdown of Earth’s ecological support system; cultural behaviors are driven by monetary incentives, rather than reducing CO2 emissions; and EPA’s estimates are within and towards the lower end of the range of SCC estimates identified in literature from the past 2 years.<sup>5,6,7,8</sup>

Commenter (2246-NRDC) notes that Table 3.2.1 of the Draft Report does not include a majority of the foreseeable impacts of climate change and specifically highlight three omitted damages “that if accounted for would result in an even higher SC-GHG: wildfire related damages which are especially significant within the United States’ borders, and the environmental and ecosystem services damages due to increasing GHG emissions.”

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<sup>4</sup> Dietz, Simon, James Rising, Thomas Stoerk, and Gernot Wagner (2021): “Economic impacts of tipping points in the climate system”, *Proceedings of the National Academy of Sciences*, 118 (34) e2103081118.

<sup>5</sup> Bressler, R.D., 2021. The mortality cost of carbon. *Nature communications*, 12(1), p.4467.

<sup>6</sup> Carleton, T. and Greenstone, M., 2021. Updating the United States Government's Social Cost of Carbon. *University of Chicago, Becker Friedman Institute for Economics Working Paper*, (2021-04).

<sup>7</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R.G., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B. and Smith, D., 2022. Comprehensive evidence implies a higher social cost of CO2. *Nature*, 610(7933), pp.687-692.

<sup>8</sup> Kikstra, J.S., Waidelich, P., Rising, J., Yumashev, D., Hope, C. and Brierley, C.M., 2021. The social cost of carbon dioxide under climate-economy feedback and temperature variability. *Environmental Research Letters*, 16(9), p.094037.

While expressing the need for swift climate action, several commenters (2313-M. Plevin-Foust, 2253-OCT) argue that the SC-GHG estimates are underestimates and do not go far enough to protect children and intergenerational equity (2253-OCT) or international equity (2313-M. Plevin-Foust). The commenters recommend revising the estimates with greater emphasis on these issues. Commenter (2313-M. Plevin-Foust) supports an even higher SCC, noting that it would result in climate stability and global security, improve public health, preserve our economy, and influence other nations to adopt the SCC.

Commenter (2398-Policy Integrity NYU) states that EPA appropriately emphasizes that the SC-GHG estimates are likely underestimates of the true marginal damages of GHG pollution. The commenter highlights numerous omitted damages and argues that the near-term discount rates should be adjusted downward.

Commenter (3183-Climate Committee) notes the improvements in EPA's SC-GHG estimates but argues that it is likely an underestimate of the value that should be used in policy.

Response A-1-3: The EPA thanks the commenters for their comments. EPA believes the methodological updates implemented in the Final Report represent a major step forward in bringing SC-GHG estimates closer to the frontier of climate science and economics and address near-term updating recommendations from the National Academies' (2017). Nevertheless, EPA acknowledges that the SC-GHG estimates presented in the Report still have several limitations, as would be expected for any modeling exercise that covers such a broad scope of scientific and economic issues across a complex global landscape. The EPA has expanded the discussion in the Final Report of the numerous categories of damages that are not currently quantified and other model limitations that lead the EPA to conclude that the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution. The EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various direct and indirect damages from GHG emissions, and look for opportunities to further improve SC-GHG estimation going forward. Some of these commenters had additional recommendations for improvement in specific aspects of the estimation methodology and process; we address these in other sections of this Appendix.

Comment: Commenter (2239-A.Fraas et al.) notes the progress made by EPA's External Review Draft, but recommends that EPA provide more clarity about the implications of the methodology choices and transparency in the representation of SC-GHG estimates, especially in light of differing opinions on how to appropriately address fundamental uncertainties involved in developing damage estimates. The commenter notes, for example, the daunting nature of this calculation has caused some researchers to argue for abandoning the SCC altogether and instead use alternative approaches that examine the cost-effectiveness of different policies.

Response A-1-4: EPA has provided increased clarity and transparency in the Final Report by expanding the discussion of the methodology underlying each component, or module, of the SC-GHG estimation process and the associated uncertainties. EPA has also added a new Appendix in the Final Report to summarize the treatment of uncertainty in each module. Responses to more detailed comments from this commenter are provided in the sections below.

Comment: Commenters (2220-WDEQ, 2401-Gov Mark Gordon, 2339-INGAA, 2413-CEI/HF, 2428-API, 2218-TCEQ and RRC) raise concerns over the inherent uncertainties in EPA’s analysis.

Commenters (2220-WDEQ, 2401-Gov Mark Gordon, 2339-INGAA) raise concerns about EPA’s calculations, specifically regarding the usage of Integrated Assessment Models (IAMs). The commenters argue that IAM-based analyses lack precision and can produce results that align with desired outcomes as the key inputs can be arbitrarily chosen.

Commenter (2413-CEI/HF) argues that “SC-GHG estimates are too speculative, and too easily manipulated for political purposes, to inform regulatory decisions.”

Commenter (2428-API) argues that the SC-GHG estimates have limited utility beyond their original intended application in cost-benefit analysis due to its significant uncertainty and malleability. The commenter highlights the wide range of uncertainty and variability associated in the SC-GHG estimates, particularly for methane and carbon dioxide. Overall, the commenter questions the broader applicability and reliability of SC-GHG estimates, emphasizes the uncertainty surrounding them, and suggests that their use be limited to cost-benefit analysis.

Commenter (2218-TCEQ and RRC) argues that EPA’s SC-GHG estimates “unjustifiably inflates the climate benefits of the proposed regulatory scheme.” The commenter notes that “The ‘benefit’ of avoided climate change cost or damages because of the assumed international methane emission reductions is unquantifiable and uncertain. Yet, the cost of compliance by both oil and gas owner/operators and states is real and immediate.” The commenter further expresses concern that EPA’s sensitivity analysis denotes that benefits from the proposed regulations would not be realized during the 2023-2035 timeframe.

Response A-1-5: All policy analysis involves uncertainty. The EPA acknowledges uncertainty in SC-GHG estimation but disagrees that the uncertainty is so great as to undermine use of SC-GHG estimates in analysis, including in the RIA for this final rule. The uncertainty in the SC-GHG estimates applied in the Final RIA is fully acknowledged and comprehensively discussed in the Final RIA, Final SC-GHG Report, and supporting academic literature. The presence of uncertainty is not a reason to exclude the best available estimates of quantified/monetized benefits, as long as it is appropriately characterized. Rather, good economic analysis, consistent with OMB Circular A-4, requires that agencies use the best available scientific, technical, and economic information to derive the best estimates of costs and benefits that they can, and then communicate to the public the limitations and uncertainties of the analyses. This is what the EPA has attempted to do in developing and discussing the updated SC-GHG estimates presented in the Final Report and applied in the Final RIA for this rulemaking.

Taken together, the methodologies adopted in EPA’s updated SC-GHG estimates allow for a more holistic treatment of uncertainty than in past estimates used by the EPA. The updates incorporate a quantitative consideration of uncertainty into all modules and use a Monte Carlo approach that captures the compounding uncertainties across modules. EPA has expanded and clarified the discussion of uncertainty throughout the Final Report, including a new Appendix A.8 and Table A.8.1 summarizing EPA's methodology for the treatment of uncertainty. EPA has

also discussed a variety of sensitivities and uncertainties in the review of the literature and in the presentation of the multiple modeling approaches in the report, including the three damage modules.

EPA addresses comments related to the time horizon of analysis within responses in Section A.2 below.

Comment: Commenters (2361-EPRI, 2227-W. Energy Alliance) provide criticism of EPA's External Review Draft and challenge the applicability of EPA's SC-GHG estimates in policy. Commenters (2428-API, 2339-INGAA, 2327-AK DEC) highlight the lack of clarity in how EPA's SC-GHG will be used.

Commenter (2361-EPRI) states that EPA's SC-GHG estimates "are not yet scientifically reliable and robust for policy use" and that the report does not satisfy the recommendations of the NASEM.

Commenter (2227-W. Energy Alliance) notes that EPA made subjective decisions in the SC-GHG estimation process that could lead to controversy (e.g., focusing on global impacts, relying on long-term economic forecasting, emphasizing risk management over potentially innovative risk-taking) and over-relies on one indicator (SCC) as a surrogate for more comprehensive policymaking inputs. The commenter argues that due to these factors, particularly reliance on SCC as an economic indicator of future CO<sub>2</sub> emission damages, it is unlikely the use of SCC will be stable through future administrations. The commenter further states that the SC-CO<sub>2</sub> should not be used in isolation when considering environmental or public policies. The commenter concludes that EPA should not use the SCC in isolation when establishing environmental, energy, or national security policy. While discussing EPA's comparison to the 2021 interim SC-CH<sub>4</sub> estimates, the commenter also claims EPA's summary to be misleading because "it is the result of using a different range of discount rates in the tables being compared". The commenter states that EPA should conduct its SC-CH<sub>4</sub> analysis more transparently.

Commenter (2339-INGAA) supports actions to reduce GHG emissions but expresses serious concerns regarding the use of the SC-GHG estimates. The commenter argues that the SC-GHG estimates are highly speculative, policy-laden, and ultimately non-scientific. The commenter argues that EPA's decisions to issue its own SC-GHG analysis, which differs substantially from the IWG's and produces much higher estimates, creates unnecessary and harmful regulatory uncertainty for industry. The commenter argues that at a minimum, SC-GHG estimates must be reached through a process that minimizes regulatory uncertainty. The commenter urges EPA to rescind its Draft Report and cease employing its different SC-GHG figures in its decision-making.

Commenter (2254-PBPA) notes that agencies that were not required to use the IWG's SCC estimates and refused to use them because of the lack of consensus on discount rate, the failure of the tool to measure actual incremental impacts of a project on the environment, and the lack of standards to determine "significant" monetized values for NEPA purposes.

Commenters (2428-API, 2339-INGAA) add that it is impossible to determine why EPA drafted the report or how it intends to use it (such as for cost-benefit analyses). Commenter (2428-API) remarks that it is unclear what EPA's Draft Report is and how its SC-GHG estimates should be used. The commenter clarifies that EPA's estimates cannot be used in sensitivity analyses as it does not achieve either of EPA's purposes for conducting a sensitivity analysis and is therefore, not suitable for use. Those purposes being either to compute the effects of altering inputs on resulting outputs of a model, or to study how uncertainty in model outputs can be correctly apportioned to various sources of uncertainty in the inputs of the model.

Commenter (2327-AK DEC) expresses concerns for relying on a calculation of the social cost of carbon that is currently being challenged in court by various states in the case of *Louisiana vs. Biden*. The commenter points out that the rulemaking fails to discuss the ongoing litigation, which is significant because it directly related to the justification for the entire rule. This comment suggests that the rulemaking process may be incomplete or inadequate in considering important legal issues and current legal challenges.

Response A-1-6: The EPA disagrees that there is a lack of clarity in the intended purpose of the report or EPA's intended use of the SC-GHG estimates in regulatory analysis. The EPA also disagrees with the assertion that the scientific basis for the SC-GHG estimates is not sufficient to support their use in regulatory analysis. Since 2008, the EPA has used estimates of the SC-GHG in analyses of regulatory actions that affect GHG emissions. In the EPA's regulatory analyses the Agency strives to use the best available science. Over time, the EPA has updated the SC-GHG estimates it uses in regulatory analysis to reflect improvements in the science. The Final Report presents a set of SC-GHG estimates that incorporates numerous methodological updates that address the near-term recommendations of the National Academies and reflect the state of the science on estimating the climate change damages associated with marginal changes in GHG emissions. The updated estimates are used in the Final RIA to monetize changes in GHG emissions expected to result from the rulemaking in the same fashion that previous estimates of the SC-GHG have been applied by the EPA since 2008.

The EPA disagrees with the commenters that suggested that the use of the SC-GHG estimates in a sensitivity did not achieve the agencies intended purpose for the sensitivity analysis. The purpose of the sensitivity analysis was to consider how the estimated climate benefits would change based on updated estimates of the SC-GHG that incorporate important methodological updates that address the near-term recommendations of the National Academies and new science. The sensitivity analysis was able to achieve that purpose.

Comments related to the process by which the SC-GHG estimates were developed are discussed in more detail and responded to in Section A.7 below. Regarding the comment about the case of *Louisiana vs. Biden*, EPA notes that this case and a companion case, *Missouri v. Biden*, have been dismissed by the courts for lack of party standing. *See Louisiana v. Biden*, 64 F.4th 674 (5th Cir. 2023); *Missouri v. Biden*, 52 F.4th 362 (8th Cir. 2022) *cert. denied*, --- S.Ct. ---, 2023 WL 6558409 (Mem) (Oct. 10, 2023).

EPA disagrees with the commenter's (EPRI) assertion that the updated SC-GHG estimates have not addressed the National Academies' recommendations. EPA discusses how the



methodological updates in each module address the National Academies' recommendations throughout Section 2 of the Final Report and summarizes this information in Section 5 of the Final Report. EPA responds to this commenter's specific comments about each module in the remaining sections of this Appendix.

Comment: Commenters (2220-WDEQ, 2339-INGAA, 2450- Williams Companies, Inc., 2353-CrownQuest Op) argue that EPA's report does not properly value the social benefits of energy and instead focuses solely on the costs of emissions. Commenter (2220-WDEQ) mentions the \$372,000,000 oil and natural gas brought to Wyoming in the form of severance taxes for fiscal year 2021. Additionally, the commenter mentions the direct and indirect employment benefits and wages associated with the oil and natural gas industry. The commenter further states that EPA is using a flawed methodology that dramatically overstates the societal benefits while significantly underestimating the costs to states and regulated entities to implement the rule.

Commenter (2339-INGAA) argues that EPA's cost-benefit analysis is one-sided in that it calculates the global costs of GHG emissions over a centuries-long time horizon but fails to calculate the societal benefits of energy over the same period. The commenter notes that the Shared Socioeconomic Pathways research, which EPA discusses but does not use, states that a Fossil-fueled Development pathway is projected to lead to global Gross Domestic Product (GDP) nearly twice as high as a Sustainability pathway that reduces fossil fuel use.

Similarly, commenter (2450-Williams Companies, Inc.) argues that EPA fails to calculate the social benefits of energy, which the commenter states, includes the long-term effects on GDP and economic growth rates, bringing households out of energy poverty, and reducing the use of harmful cooking gas.

Commenter (2353-CrownQuest Op) criticizes the EPA report stating, "Never does the report consider the benefits hydrocarbon production provides to our society."

Response A-1-7: A rule that affects GHG emissions may also affect the production or consumption of goods and services, in which case it could create costs and benefits for businesses and households that either produce or use those goods and services. These costs and benefits are important to include in an analysis of the rule's impacts but are not the result of changes in GHG emissions from the rule and therefore, it would be inappropriate to try and include them in the SC-GHG used to value changes in GHG emissions. In other words, the SC-GHG is not a measure of social welfare from the consumption of goods and services whose production results in GHG emissions, nor is it intended to capture other positive or negative externalities associated with the production of those goods and services. Similarly, the SC-GHG is not intended to capture the benefits or costs to society from the production and consumption of goods and services associated with regulatory compliance, or the impacts from changes in other emissions that may also occur as a result of regulatory compliance. The SC-GHG is just one component of a larger analysis that includes consideration of other potential relevant impacts of a policy, including the social costs of compliance, labor market changes, and changes in emissions of other pollutants, as appropriate for the specific analysis.

## A.2 Socioeconomic and Emissions Module

Comment: Several commenters provide supportive statements specific to the use of the Resources for the Future Socioeconomic and Emissions Projections (RFF-SPs; Rennert et al. 2022a<sup>9</sup>) in the socioeconomic and emissions module of the EPA’s draft update.

Commenter (2349-RFF) expresses support for EPA’s socioeconomic module, highlights its utility, and argues that it addresses the recommendations of the National Academies of Science, Engineering, and Medicine. The commenter states that the long-run socioeconomic projections used in the EPA Report combine expert judgement and statistical information, can account for future policies and dependencies between variables, and provide the associated uncertainty bounds of socioeconomic projections. The commenter notes that the methodology is published in a peer-reviewed study.<sup>10</sup>

Commenter (2246-NRDC) applauds the EPA’s draft update for being “grounded in up-to-date science and economics” that “appropriately applies recommendations made by the [National Academies] to update both how the SC-GHG analysis is conducted and key parameters.” The commenter emphasizes that the modular approach enables better consistency, transparency, and the representation of uncertainty and probability ranges for estimates of the SC-GHG” and “enables timely updates... as new scientific literature becomes available.” With regard to the socioeconomic module, the commenter states that the usage of RFF-SPs provides three advantages to the status quo. First, the commenter notes that the RFF-SPs can be regularly updated to reflect the changing conditions and changes in expert predictions of economic growth, and the probabilities assigned to different outcomes can be re-weighted accordingly. Second, the commenter highlights that the RFF-SPs predict economic growth through 2300, which enables a more accurate estimation of economic damages through that timeframe. Third, the commenter states that the RFF SPs link discount rates to expected economic growth and thus enable accounting for economic growth uncertainty in how future damages are discounted.

Response A-2-1: The EPA thanks the commenters for their supportive comments regarding the modular approach and the use of the RFF-SPs in the socioeconomic and emissions module.

Comment: Commenter (2398-Policy Integrity NYU) credits EPA with developing a state-of-the-art modular integrated assessment model consistent with the recommendations of the National Academies. The commenter encourages EPA to use its model to also calculate SC-GHG estimates and the total cost of climate change using socioeconomic and emissions projections for each of the Shared Socioeconomic Pathways (SSPs), which the commenter states, spans the likely emission space. The commenter notes that this information is not needed for regulatory

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<sup>9</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022. The social cost of carbon: advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity*, 2021(2), pp.223-305.

<sup>10</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022. The social cost of carbon: advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity*, 2021(2), pp.223-305.

cost-benefit analysis, but that these values would demonstrate the scale of benefits of various global greenhouse gas emission targets, which “could inform public and policymaker opinion of the scale of climate action necessary and/or justifiable.”

Response A-2-2: The EPA Draft SC-GHG Report discusses the SSPs, recognizes the use of these deterministic socioeconomic projections in the IPCC report and other applications, and presents a direct comparison of the RFF-SPs to the SSPs. EPA has expanded this discussion and presentation in the Final Report. The discussion explains that while the SSPs generally fall within or near the range of the RFF-SP probabilistic projections, they are limited in providing a comparison to the full RFF-SP distribution. The SSPs were intentionally developed to reflect a range of reasonably likely scenarios corresponding to different storylines rather than a more comprehensive range of plausible scenarios like the RFF-SPs. The SSPs were also only developed to provide projections out to 2100 and, as shown in the Final Report, long term SSP-based projections are sensitive to the post-2100 extrapolation method used. The SSPs were intentionally developed without probabilities attached to them, making them less suitable for addressing uncertainty. SSP-based projections of economic growth, for example, vary depending on which of the three available alternative interpretations of the SSPs (from the IIASA, OECD, or PIK economic growth model) is selected from the SSP database. The SSP developers explicitly note that the provided “‘illustrative’ SSP should not be interpreted as the central or representative case...It is recommended to use the GDP projections by all teams to test the sensitivity of the results due to different GDP assumptions.”<sup>11</sup> Therefore, any estimates of the SC-GHG for each SSP ignore the significant role of socioeconomic uncertainty in the estimates of the SC-GHG. EPA, however, notes that if such illustrative estimates are of interest to the commenter, the GIVE model does allow users to estimate climate damages using a given deterministic SSP-based socioeconomic scenario and emission scenario, and single post-2100 extrapolation method, as an input to the model (<https://github.com/rffscghg/MimiGIVE.jl>). However, the use of such a deterministic growth and emissions trajectory prevents the representation of significant uncertainties in both the damages and discounting module which was recommended by the National Academies (2017).<sup>12</sup> Therefore, EPA disagrees with the commenter and believes that an SSP-based SC-GHG calculation would be of limited additional value in informing policymakers and the public of the scale of benefits associated with GHG emission reductions.

Comment: Commenter (2239-A. Fraas et al.) highlights the significant uncertainty in projections of economic growth through the year 2300 and notes that certain assumptions of exogenous growth, exogenous preferences, and utility function stability become more tenuous in longer time

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<sup>11</sup> Keywan Riahi, Detlef P. van Vuuren, Elmar Kriegler, Jae Edmonds, Brian C. O'Neill, Shinichiro Fujimori, Nico Bauer, Katherine Calvin, Rob Dellink, Oliver Fricko, Wolfgang Lutz, Alexander Popp, Jesus Crespo Cuaresma, Samir KC, Marian Leimbach, Leiwen Jiang, Tom Kram, Shilpa Rao, Johannes Emmerling, Kristie Ebi, Tomoko Hasegawa, Petr Havlík, Florian Humpenöder, Lara Aleluia Da Silva, Steve Smith, Elke Stehfest, Valentina Bosetti, Jiyong Eom, David Gernaat, Toshihiko Masui, Joeri Rogelj, Jessica Streffer, Laurent Drouet, Volker Krey, Gunnar Luderer, Mathijs Harmsen, Kiyoshi Takahashi, Lavinia Baumstark, Jonathan C. Doelman, Mikiko Kainuma, Zbigniew Klimont, Giacomo Marangoni, Hermann Lotze-Campen, Michael Obersteiner, Andrzej Tabeau, Massimo Tavoni. SSP Database (Shared Socioeconomic Pathways) - Version 2.0, <https://tntcat.iiasa.ac.at/SspDb/dsd?Action=htmlpage&page=10>.

<sup>12</sup> National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. National Academies Press.

frames. The commenter recommends that EPA temporally disaggregate the distributional effects of the SC-GHG estimates into three groupings: the present to 2100; from 2101 to 2200; and from 2201 to 2300. The commenter argues that it is appropriate for the public, who is bearing the cost of the regulatory actions, to see how the benefits of climate policies are distributed among generations. The commenter states that the assumptions underlying the modeling are not sufficiently justified, including the distribution of uncertainty around input parameters, such as population size, economic growth, discount rates, and surface temperatures. Given the input uncertainties that EPA documents, the commenter believes that it is not credible to present SC-GHGs as point estimates for the years beyond 2030, and EPA should instead present them as distributions.

Response A-2-3: Thank you for the comments. EPA has added information in the Final Report to aid the reader in understanding the temporal evolution of the discounted marginal damages. A temporal disaggregation of discounted marginal damages from CO<sub>2</sub> emissions is provided in Extended Data Fig. 2 in Rennert et al. (2022b)<sup>13</sup> for the Greenhouse Gas Impact Value Estimator (GIVE) model. This figure shows the contribution of discounted damages in each year to the SC-CO<sub>2</sub>. The figure also includes the distribution of the discounted damages. The point estimates provided in the report are the certainty equivalent SC-GHG as defined in Section 2.5 of the report and is consistent with the consumption capital asset pricing model. The SC-GHG is calculated from a distribution of discounted marginal damages. This distribution is provided in the Final Report (in Section 3.1 for CO<sub>2</sub> and in the Appendix for methane and nitrous oxide). EPA has also substantially expanded the discussion of the development of the RFF-SPs in Section 2.1 of the Final Report to include a more detailed explanation of the methods used, the sources of uncertainty and the plausibility of socioeconomic projections. Further, EPA has introduced a supplementary Table A.8.1 in Appendix A.8. that provides a concise summary of the treatment of uncertainty in each module, including the socioeconomic and emissions module. EPA notes that these details were available in public documents through the provided citations and EPA has simply added some of the details provided in the references to the report itself.

Comment: Commenters (2361-EPRI, 2344-IER, 2227-W. Energy Alliance, 2428-API) provided feedback on the socioeconomic and emissions module, emphasizing the importance of clarity, consistency, and coherence. The commenters stated that additional module documentation and methodological details are necessary for full assessment. The commenters noted that EPA's socioeconomic module contains potentially implausible socioeconomic projections or is not appropriately modeling GHG reduction policies.

Commenter (2361-EPRI) argues that EPA's socioeconomic and emissions module does not fully satisfy the recommendations put forth by the National Academies of Sciences, Engineering, and Medicine (NASEM) with respect to transparency, scientific basis, and treatment of uncertainty. The commenter states that the socioeconomic module documentation should be enhanced to allow for a full evaluation of the methodology, including a further justification of model parameters, and a consideration of the broader academic literature (e.g., scenarios used in IPCC

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<sup>13</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692.

work (Clarke et al. 2014<sup>14</sup>, Huppmann et al. 2018<sup>15</sup>, Byers et al. 2022<sup>16</sup>), IEA (2021<sup>17</sup>, 2019<sup>18</sup>), Morris et al. (2022)<sup>19</sup>, and Rose et al. forthcoming<sup>20</sup>). Similarly, the commenter argues that the Rennert et al. (2022b)<sup>21</sup> paper that EPA relies on lacks the internal consistency, coherency, and transparency regarding the expert elicitation process and the absence of details necessary for evaluating and understanding the projections and probabilities assigned to future policies. The commenter further emphasizes the importance of including socioeconomic structural details, such as population composition, as well as structural transition uncertainty in the projections. The commenter highlights deep uncertainties related to economic development that is independent from climate policy, as well as uncertainties stemming from climate policy design.

Commenter (2361-EPRI) expresses support for additional methodological details and results to facilitate a full assessment. Specifically, the commenter suggests that the socioeconomic module documentation should add the following information: 1) all module methodological details, an assessment and comparison to the literature, and further justification of assumptions, 2) implemented equations and parameters, 3) presentation and evaluation of the quantitative relationship between population, economic growth, and emissions projections, 4) a greater discussion and justification for the implied/assumed/modeled evolution of the structure of global and regional economies, populations, and climate policies (country ambition, timing, and design) from the present until 2300, and (5) the addition of minimum and maximum values to all figures. The commenter cites the need for socioeconomic projections to be integrated into the damages and discounting modules and for discussions regarding how the socioeconomic projections affect societal vulnerability, adaptation, and net economic damages and discounting.

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<sup>14</sup> Clarke L, K Jiang, K Akimoto, M Babiker, G Blanford, K Fisher-Vanden, J-C Hourcade, V Krey, E Kriegler, A Löschel, D McCollum, S Paltsev, S Rose, PR Shukla, M Tavoni, BCC van der Zwaan, DP van Vuuren, 2014: Assessing Transformation Pathways. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the IPCC [Edenhofer, O., R. PichsMadruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

<sup>15</sup> Huppmann, D, E Kriegler, V Krey, K Riahi, J Rogelj, SK Rose, J Weyant, et al., 2018. IAMC 1.5°C Scenario Explorer and Data hosted by IIASA. Integrated Assessment Modeling Consortium & International Institute for Applied Systems Analysis. doi: 10.22022/SR15/08-2018.15429.

<sup>16</sup> Byers, E, V Krey, E Kriegler, K Riahi, R Schaeffer, J Kikstra, R Lamboll, Z Nicholls, M Sanstad, C Smith, K-I van der Wijst, A Al Khourdajie, F Lecocq, J Portugal-Pereira, Y Saheb, A Strømman, H Winkler, C Auer, E Brutschin, M Gidden, P Hackstock, M Harmsen, D Huppmann, P Kolp, C Lepault, J Lewis, G Marangoni, E Müller-Casseres, R Skeie, M Werning, K Calvin, P Forster, C Guivarch, T Hasegawa, M Meinshausen, G Peters, J Rogelj, B Samset, J Steinberger, M Tavoni, D van Vuuren, 2022. AR6 Scenarios Database hosted by IIASA. International Institute for Applied Systems Analysis. doi: 10.5281/zenodo.5886911. url: data.ece.iiasa.ac.at/ar6/.

<sup>17</sup> IEA (International Energy Agency), 2021. Net Zero by 2050: A Roadmap for the Global Energy Sector, <https://www.iea.org/reports/net-zero-by-2050>.

<sup>18</sup> IEA (International Energy Agency), 2019. World Energy Outlook 2019, November, pp810, <https://www.iea.org/reports/world-energy-outlook-2019>.

<sup>19</sup> Morris, J. J. Reilly, S. Paltsev, A. Sokolov and K. Cox (2022): Representing socio-economic uncertainty in human system models. *Earth's Future*, 10(4). doi: 10.1029/2021EF002239.

<sup>20</sup> Rose, SK, J Morris, A Gurgel, forthcoming. Quantifying uncertainty in global and sub-global socioeconomic and greenhouse gas emissions futures.

<sup>21</sup> Rennert, K, F Errickson, BC Prest, L Rennels, R Newell, W Pizer, C Kingdon, J Wingenroth, R Cooke, B Parthum, D Smith, K Cromar, D Diaz, F Moore, U Müller, R Plevin, A Raftery, H Ševčíková, H Sheets, J Stock, T Tan, M Watson, T Wong, D Anthoff, 2022. Comprehensive evidence implies a higher social cost of CO2. *Nature* 610: 687–692.

The commenter also emphasizes the need to revise module documentation to clearly communicate the connections and relationships between different modules. Furthermore, the commenter states that EPA has chosen to constrain its module choices to what others have already done in the peer reviewed literature, which causes issue in terms of robustness and inconsistencies (from combining pieces from different studies). Lastly, the commenter states that there is clearly more information available than what is currently being considered in the methodology and encourages EPA to utilize a larger number of academic studies.

Commenter (2361-EPRI) states that emissions projections used by EPA are an implausible socioeconomic pathway, especially for the post-2100 projection assumptions. Furthermore, the commenter states that pathways should be assessed for their plausibility, and pathways with negligible plausibility of occurrence should be removed. An example of this is the EPA projection that greenhouse gas emissions will peak this decade. According to the commenter, this is extremely unlikely given historical trends, so the results with emissions peaking this decade or earlier should be removed. In general, the commenter asserts a preference for assessing the plausibility or likelihood of each pathway actually occurring and focusing on the pathways that are more likely or more probable to occur. The commenter asserts that some of the key assumptions used in the Rennert et al. (2022b) analysis, including the assumption that global economic growth rates will decline after 2100, require additional justification.

Commenter (2227-W. Energy Alliance) finds the *Nature* article<sup>22</sup> (cited by EPA)'s conclusion that CO<sub>2</sub> emissions will continue through 2300 inconsistent with the Paris Climate Agreement. To that end, the commenter expresses confusion at EPA's use of the 2300 GHG timeline, in comparison to the administration's commitment to limiting climate change through the Agreement. The commenter expresses support for EPA's assumption that CO<sub>2</sub> emissions will not reach net zero by 2300 and recommends that EPA estimate SCC in time horizons where greenhouse gas emissions (including CO<sub>2</sub> and methane CH<sub>4</sub>) reach net zero by 2100, 2200, and 2300, to allow for comparison of costs and benefits associated with different levels of GHG-reducing policies.

Commenter (2428-API) argues that EPA should explain why its global emissions projection does not reflect globally coordinated action, given that this is a key rationale for the use of global SC-GHG estimates. The commenter asks that EPA provide documentation related to the RFF paper upon which EPA's modeling relies, including how and why certain experts were chosen to assist in forecasting, how RFF selected experts from nominee pool, as well as documentation of RFF survey methodologies and results.

Commenter (2344-IER) states that EPA's "science fiction time horizons are inappropriate." The commenter provides quotes from the EPA report summarizing the post-2100 extrapolations used in the IWG's socioeconomic scenarios and then argues that EPA does not properly justify its projections of the world's energy system into the 2200s. The commenter describes alternative

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<sup>22</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

projections from Star Trek, in which significant technological discoveries are made, and states that even though Star Trek is a fictional show, EPA does not justify believing its projections over Star Trek's.

Response A-2-4: EPA appreciates the commenters' statements that estimations should be developed through cogent modulation and methodologies, the rationale for which ought to be made available for public review. To address the commenters' request for additional documentation, EPA substantially expanded the discussion in Section 2.1 of the Final Report describing the development of the RFF-SPs, to include a more detailed discussion of the methods used, the sources of uncertainty and the plausibility of socioeconomic projections. Further, EPA has introduced a supplementary Table A.8.1 in Appendix A.8. that provides a concise summary of the treatment of uncertainty in each module, including the socioeconomic and emissions module. EPA notes that these details were available in public documents through the provided citations and EPA has simply added some of the details provided in the references to the report itself. Additional details on the development of the RFF-SPs including the expert elicitation process, methodological details, an assessment and comparison to the literature, implemented equations and parameters, quantitative relationships are provided in Rennert et al. (2022a)<sup>23</sup>, including in the online appendix to Rennert et al. (2022a)<sup>24</sup>, and the relevant journal articles (Müller et al. 2022<sup>25</sup>, Raftery and Ševčíková 2023<sup>26</sup>).

EPA acknowledges commenters' concern about the challenges involved in assessing long term socioeconomic projections. Likewise, the National Academies recognized that their recommendations for the socioeconomic module "may entail projecting GDP, population and emissions two to three centuries into the future, which presents a significant challenge" (National Academies 2017, p. 90)<sup>27</sup>. To meet this challenge, the National Academies recommended the reliance on statistical methods to project historical data combined with elicitation of expert judgement to produce probabilistic projections and that good scientific practices be followed, including with respect to transparency, scientific basis, treatment of uncertainty and that methods be consistent with the available peer-reviewed literature. As described in the Final Report, the RFF-SPs used in the socioeconomic module underlying EPA's updated SC-GHG estimates are consistent with the National Academies' recommendations. They were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and

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<sup>23</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity*. Fall 2021, pp.223-305.

<sup>24</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity, Online Appendix*. [https://media.rff.org/documents/Rennert\\_et\\_al.\\_BPEA\\_Appendix.pdf](https://media.rff.org/documents/Rennert_et_al._BPEA_Appendix.pdf)

<sup>25</sup> Müller, U.K., Stock, J.H. and Watson, M.W., 2022. An Econometric Model of International Growth Dynamics for Long-Horizon Forecasting. *Review of Economics and Statistics*, 104(5), pp.857-876.

<sup>26</sup> Raftery, A.E., and H. Ševčíková. 2023. Probabilistic population forecasting: Short to very long-term. *International Journal of Forecasting*. 39(1), 73-97.

<sup>27</sup> National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. National Academies Press.

technological developments, and provide the level of disaggregation necessary for damage calculations. Unlike other sources of projections, they provide inputs for estimation out to 2300 without the need for EPA to make post-2100 extrapolation assumptions. The EPA disagrees with the commenter's description that Rennert et al. (2022a) "assume" that global economic growth rates decline after 2100 and that this needs more justification. The RFF-SP probabilistic economic growth projections are based on Müller et al.'s (2022) statistical model combined with the results of a formal expert elicitation of 10 leading macroeconomics and growth economists, conducted individually. As part of the elicitation, the experts first quantified their uncertainty for a set of calibration questions, the results of which were used to performance-weight the experts in the final combination. Experts demonstrated a high level of statistical accuracy on the calibration questions. The elicitation focused on quantifying uncertainty for a representative frontier of economic growth in OECD countries for four years (2050, 2100, 2200, 2300). In general, the experts tended to agree with each other that median economic growth would slow between 2050 and 2300. Where experts tended to disagree was on the amount of uncertainty in future projections. However, 9 out of 10 of the experts estimated an uncertainty range that was narrower than the Müller et al. (2022) projections.

EPA disagrees with the commenter's (2361-EPRI) suggestion that EPA should selectively remove "arguably implausible" pathways from the peer-reviewed RFF-SP probabilistic projections. EPA has no scientific rationale for ignoring parts of the peer reviewed published projections or adjusting the distributions on an ad hoc basis. The economic growth and population projections comport with very-long term historical relationships and were developed by leading experts in their respective fields. The EPA disagrees with the commenter that projections of CO<sub>2</sub> emissions peaking this decade should be removed from the analysis as implausible. The probabilistic emissions projections should represent the full distribution of possible outcomes. Following the National Academies' recommendations, RFF designed the survey in a way that asked the experts to incorporate the expected evolution of future policy in their responses. As presented in Rennert et al. (2022a), under the median economic growth trajectory, the combined results of the experts' responses suggested a probability of approximately 50% that emissions would decline by 2050 from today's levels (see Figure 7 in Rennert et al. 2022a). The commenter's assertion that there is no probability that emissions will peak this decade is not consistent with other emissions projections. Since 2021, the International Energy Agency annual outlook has projected that CO<sub>2</sub> emissions could peak this decade based on the stated policies scenario (IEA 2021<sup>28</sup>, 2022<sup>29</sup>, 2023<sup>30</sup>). EPA agrees with the commenter that assigning a likelihood to the pathways is preferable. By using a probabilistic approach, the estimates that EPA utilizes assigns the likelihood of each pathway occurring.

EPA thanks the commenter (2361-EPRI) for providing citations for additional information to consider for the socioeconomic module. Some of the citations are to information that has already been discussed and presented in the report, such as the SSP scenarios used in IPCC Assessment Reports. The commenter also suggested that EPA consider other population projections, such as those developed by the United Nations (UN). The population projections in the RFF-SPs are an extension of the methodology used for the UN population projections. The EPA has expanded

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<sup>28</sup> IEA (2021), *World Energy Outlook 2021*, IEA, Paris <https://www.iea.org/reports/world-energy-outlook-2021>

<sup>29</sup> IEA (2022), *World Energy Outlook 2022*, IEA, Paris <https://www.iea.org/reports/world-energy-outlook-2022>

<sup>30</sup> IEA (2023), *World Energy Outlook 2023*, IEA, Paris <https://www.iea.org/reports/world-energy-outlook-2023>



the discussion in Section 2.1 of the Final Report to provide details on the consistency of the RFF-SP population projections to the UN population projections that end in 2100. The EPA has also expanded the discussion of existing socioeconomic projections developed using MIT's Emissions Prediction and Policy Analysis (EPPA) Model to now also reference updated probabilistic socioeconomic projections based on the EPPA model (Moore et al. 2022)<sup>31</sup>. EPA looks forward to reviewing the forthcoming EPRI-MIT socioeconomic work (Rose et al. forthcoming)<sup>32</sup> mentioned by the commenter when it is available. The EPA will continue to follow these and other advances in the published literature on long term socioeconomic projections and look for opportunities to incorporate peer reviewed methodological advances that address the National Academies longer term recommendations for this module in future updates of the SC-GHG estimates.

One commenter expressed confusion about the RFF-SPs projection of emissions through 2300 in comparison to the GHG mitigation commitments under the Paris Agreement. As described in the SC-GHG Report, under the RFF-SPs, GHG emissions are projected using expert elicitation techniques. Within the survey questions posed, the experts were asked to incorporate their views about changes in technology, fuel use, and other conditions, including the expected evolution of future policies (such as those made under the Paris Agreement). In Section 2.1 of the Final Report, EPA has expanded the discussion of the methods used to develop the RFF-SP emission projections, including what the experts reported regarding the factors they considered under different economic growth scenarios. For example, to support the high-end emissions, it was common for experts to state that low economic growth could lead countries to revisit emission reduction pledges. Additional details on experts' rationales regarding changes in fossil fuel and process-related CO<sub>2</sub> emissions, natural CO<sub>2</sub> stocks, negative emissions technologies, and CH<sub>4</sub> and N<sub>2</sub>O emissions in the context of the Paris Climate Agreement are available in Rennert et al. (2022a) and the accompanying online appendix.

Regarding the comment about appropriate time horizons, it is unclear why the commenter referenced the post-2100 extrapolation methods developed by the IWG in 2010 for the socioeconomic projections underlying the IWG recommended SC-GHG estimates. The socioeconomic module used in EPA's update SC-GHG analysis relies on the RFF-SPs (Rennert et al. 2022a). As described in the Report, the RFF-SPs are a set of probabilistic projections of population, GDP, and GHG emissions (CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O) to 2300. Consistent with the National Academies' recommendation, the RFF-SPs were developed using a mix of statistical and expert elicitation techniques to capture uncertainty in a single probabilistic approach, taking into account the likelihood of future emissions mitigation policies and technological developments, and unlike other sources of projections, they provide inputs for estimation out to 2300 without further extrapolation assumptions. This is a suitable time horizon consistent with

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<sup>31</sup> Moore, F.C., Lacasse, K., Mach, K.J., Shin, Y.A., Gross, L.J. and Beckage, B., 2022. Determinants of emissions pathways in the coupled climate–social system. *Nature*, 603(7899), pp.103-111.

<sup>32</sup> Rose, SK, J Morris, A Gurgel, forthcoming. Quantifying uncertainty in global and sub-global socioeconomic and greenhouse gas emissions futures.

the National Academies' recommendation<sup>33</sup> and OMB Circular A-4 (2003) guidance<sup>34</sup>, since in the modeling conducted for this report 2300 is far enough in the future to capture the majority of discounted climate damages. See Section 2.1 and 3 of the Final Report for more discussion.

Comment: Commenters (2413-CEI/HF, 2227-W. Energy Alliance) highlight the need for EPA to elucidate the disparities in CO<sub>2</sub> emissions between revised and prior assessments.

Commenter (2413-CEI/HF) notes that EPA's External Review Draft projects that CO<sub>2</sub> emissions in 2300 will be less than one third of what the IWG analysis predicts, however, EPA's resulting SCC estimates in 2080 are 3 to 4 times higher than the IWG estimates. The commenter criticizes EPA for not discussing this "paradox" and remarks that the change in the central discount rate is undoubtedly a factor in this dichotomy. The commenter additionally requests that EPA produce charts to compare IWG and RFF-SP emission projects for CH<sub>4</sub> and N<sub>2</sub>O emissions.

Commenter (2227-W. Energy Alliance) similarly recommends that EPA should explain in the RIA that the cumulative CO<sub>2</sub> emissions used in the revised SC-CO<sub>2</sub> estimates are based on cumulative CO<sub>2</sub> emissions that are significantly lower than cumulative CO<sub>2</sub> emissions values used in previous SC-CO<sub>2</sub> estimates, with further explanations as to why cumulative CO<sub>2</sub> emissions are only about 28% of the emission values used in past SC-CO<sub>2</sub> estimates, but the estimates SC-CO<sub>2</sub> (using a comparable 3% discount rate) is now 57% larger (\$80/tCO<sub>2</sub> versus \$51/tCO<sub>2</sub>).

Response A-2-5: EPA has expanded the discussion of the relative contribution of several modelling changes in Section 4.1 of the Final Report. As explained in the Report, the increases in the SC-GHG estimates relative to the IWG recommended interim estimates are due to the combined effect of the methodological updates, some of which are integrated in a way that makes a complete decomposition of the incremental contribution of each change difficult. For example, a comparison of SC-GHG estimates based on a constant 3% discount rate with results based on a 2% near-term Ramsey discount rate reflects the combined effect of using a lower near-term rate and the shift from a constant to a dynamic discounting approach that accounts for any correlation between climate change damages and economic growth through the use of probabilistic RFF-SPs growth projections. A re-estimation of the IWG recommended interim estimates using lower constant discount rates finds that the SC-CO<sub>2</sub> increases from \$51/mtCO<sub>2</sub> to \$121/mtCO<sub>2</sub> for 2020 emissions when shifting from a constant 3% to a constant 2% discount rate (NYSDEC 2022)<sup>35</sup>. This illustrates that the combined effect of shifting to a dynamic discount rate approach together with the socioeconomic, climate, and damage module updates accounts for the additional 60% increase in the SC-CO<sub>2</sub> to \$190/mtCO<sub>2</sub> for 2020 emissions.

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<sup>33</sup> The National Academies (2017) recommended that socioeconomic scenarios used to estimate the SC-GHG should: "extend far enough in the future to provide inputs for estimation of the vast majority of discounted climate damages".

<sup>34</sup> Regarding the analytic time horizon for regulatory benefit-cost analysis, OMB Circular A-4 (2003) advises "The ending point should be far enough in the future to encompass all the significant benefits and costs likely to result from the rule" (OMB 2003). OMB Circular A-4 (2023) similarly advises "The ending point for your analysis should be far enough in the future to encompass, to the extent feasible, all the important benefits and costs likely to result from all regulatory alternatives being assessed" (OMB 2023).

<sup>35</sup> New York State Department of Environmental Conservation (NYSDEC), 2022. Establishing a Value of Carbon: Guidelines for Use by State Agencies. [https://www.dec.ny.gov/docs/administration\\_pdf/vocguid22.pdf](https://www.dec.ny.gov/docs/administration_pdf/vocguid22.pdf).

This does not imply that each update influences the SC-GHG in the same direction. For example, ignoring the correlation between climate change damages and economic growth – as is the case with a constant discount rate approach – can lead to overestimating the SC-GHG if there is a positive correlation between economic growth and marginal damages (Newell, Pizer, Prest 2022)<sup>36</sup>. In the case of methane, the IWG interim SC-CH<sub>4</sub> estimate under a 2% constant discount rate (\$2,700/mtCH<sub>4</sub> for 2020 emissions (NYSDEC 2022)) exceeds the fully updated SC-CH<sub>4</sub> estimate under a 2% near-term Ramsey discount rate. The Report also discusses additional comparative analysis from Rennert et al. (2022b)<sup>37</sup> that illustrates to the extent possible the incremental impact of some of the updates in the GIVE model, relative to a recent version of the DICE model.

In response to the commenter’s request, additional figures have been included in Appendix A.6 of the Report presenting the net annual global emissions of CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O under the RFF-SPs and the IWG’s EMF-22 based emissions scenarios from 1900 to 2300.

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<sup>36</sup> Newell, R. G., Pizer, W. A. & Prest, B. C. A Discounting Rule for the Social Cost of Carbon. J. Assoc. Environ. Resour. Econ. (2022a).

<sup>37</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

### A.3 Climate Module

Comment: Among the commenters expressing strong support for EPA’s draft update, several commenters provided comments specific to the climate module (2208-CCES et al., 2246-NRDC, 3174-Climate Science et al., 2194-S. Dietz et al., 2398-Policy Integrity NYU).

Commenter (2208-CCES et al.) supports EPA’s Draft Report for closely following the 2017 roadmap provided by the National Academies of Sciences regarding the social cost of greenhouse gases. The commenter noted that the National Academies recommended that the climate module “reflect current scientific understanding of the relationships between greenhouse gas emissions, concentrations, radiative forcing, and global mean surface temperature change” and specifically endorsed the FaIR model that EPA adopted as satisfying those criteria.

Commenters (2246-NRDC, 2398-Policy Integrity NYU) state that the EPA’s climate module is consistent with NASEM’s recommendations. More specifically, commenter (2446-NRDC) states that EPA appropriately applies recommendations made by the NASEM to update both how the SC-GHG analysis is conducted and key input parameters. With respect to the climate module, the commenter states that EPA’s climate module applies the “latest scientific consensus on the relationship between carbon emissions and temperature and sea-level rise.” The commenter applauds the Draft Report’s use of the FaIR model for its more robust representation of uncertainties and projections. The commenter states that the FaIR model methodology results in “ranges of emissions and temperature increase [that] better represent uncertainties in emissions projections, physical carbon cycle uncertainty, and physical climate uncertainty (all of which are built into FaIR) than the status quo.”

Some commenters (3174-Climate Science et al., 2194-S. Dietz et al., 2398-Policy Integrity NYU), while expressing general support for EPA’s efforts to improve estimates of the SC-GHG, discuss areas in which the climate module does not yet fully capture various climate dynamics and potential tipping points. These commenters emphasize that by not modeling the effect of tipping points, the resulting SC-GHG values will be an underestimate of the true cost of GHG emissions.

Commenter (3174-Climate Science et al.), while providing support for EPA’s improved SC-GHG estimates, notes that several key omissions lead to a “gross underestimation” and argues that this is an “especially egregious failing.” In particular, the commenter notes EPA’s admission that it has not included (or partially included) the impact of extreme weather events, temperature and precipitation extremes, ocean acidification, non-linear sea level rise, damages to ecosystems, and the effect of climate change on migration, displacement, labor productivity, and national security, among many other categories of omitted damages. The commenter cites recent peer-reviewed scientific research that highlights the dangers of 2 degree C warming.<sup>38</sup>

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<sup>38</sup> Hansen, J., Sato, M., Hearty, P., Ruedy, R., Kelley, M., Masson-Delmotte, V., Russell, G., Tselioudis, G., Cao, J., Rignot, E., Velicogna, I., Tormey, B., Donovan, B., Kandiano, E., von Schuckmann, K., Kharecha, P., Legrande, A. N., Bauer, M., and Lo, K.-W.: Ice melt, sea level rise and superstorms: evidence from paleoclimate data, climate modeling, and modern observations that 2 °C global warming could be dangerous, *Atmos. Chem. Phys.*, 16, 3761–3812, <https://doi.org/10.5194/acp-16-3761-2016>, 2016.

Commenter (2194-S. Dietz et al.) congratulates EPA “on their excellent work that follows many of the recent advances in climate economics” but notes that quantification of the effect of tipping points in the climate system on the SC-GHG is possible. The commenter recommends that EPA directly incorporate elements of their recently published research on eight tipping points<sup>39</sup> into the climate module rather than including only a qualitative discussion of it. Specifically, the commenter recommends incorporating the modules from their Model for Economic Tipping point Analysis (META) model that represent several tipping points: the dieback of the Amazon rainforest, the Indian summer monsoon (ISM) variability, the weakening of the Atlantic Meridional Overturning Circulation (AMOC), the surface albedo feedback, and the permafrost carbon feedback. The commenter states that they would be happy to advise EPA on suitable parameter settings for running META. The commenter acknowledges three caveats related to missing impact avenues in two of these tipping points: 1) the weakening of the Atlantic meridional overturning circulation, which has only been considered as having beneficial temperature impacts, but would also change precipitation patterns, potentially leading to increased damages; 2) aspects beyond additional carbon release resulting from the Amazon dieback, such as loss of biodiversity or ecosystem services, are missing from economic literature, underestimating damages stemming from the dieback; and 3) some interactions between tipping points do not rely upon direct modelling of geophysical impacts, but rather quantified expert judgements. The commenters note that their modules for other tipping points are either already implicitly accounted for in the GIVE model (i.e., disintegration of both the Greenland and West Antarctic ice sheets) or should only be used in sensitivity analysis due to remaining uncertainties (e.g., the release of ocean methane hydrates). The commenter further states that by omitting tipping points from the analysis will thereby underestimate the true SC-GHG, and the resulting policies relying on these estimates will not be stringent enough.

Similarly, commenter (2398-Policy Integrity NYU) agrees that tipping points should be included. Specifically, the commenter notes that EPA’s climate-economic module “lacks a singular tipping point used in the Working Group’s damage models, which directly impacts human welfare through lost consumption.” Such a singular tipping point representation in the damage models can represent the various “environmental tipping points triggered by climate change more generally.” Additionally, the commenter states that EPA excludes other tipping points that were not included in the Working Group’s models but should be included in EPA’s model – such as social tipping points, interactions resulting from runaway climate change due to the melting of methane hydrates and permafrost and diebacks of the Amazon and boreal forests, and the impact of society on emissions through feedback effects. The commenter recommends that EPA adopt the Dietz et al. (2021)<sup>40</sup> “modeling strategy into the modular IAM,” but commenter notes, “the resulting damage valuations would likely still represent an underestimate due to missing tipping points and connections, as well as omitted non-market impacts.” Alternatively, the commenter suggests adopting a reduced-form estimates of the damages from tipping points based on Dietz et al.’s results, rather than explicitly modeling each tipping point

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<sup>39</sup> Dietz, Simon, James Rising, Thomas Stoerk, and Gernot Wagner (2021): “Economic impacts of tipping points in the climate system,” *Proceedings of the National Academy of Sciences*, 118 (34) e2103081118.

<sup>40</sup> Dietz, Simon, James Rising, Thomas Stoerk, and Gernot Wagner (2021): “Economic impacts of tipping points in the climate system,” *Proceedings of the National Academy of Sciences*, 118 (34) e2103081118.

and their interconnectedness (This latter recommendation for an alternative approximation approach is discussed in the Damages Module section of comments below).

Commenter (2227-W. Energy Alliance) presents a divergent view on the topic of climate tipping points. The commenter commends EPA for not incorporating tipping points in the draft estimates and recommends the Agency cite the Dietz et al. (2021)<sup>41</sup> paper *in support of* this decision and note their relatively low impact on SC-CO<sub>2</sub> estimates. The commenter interprets the study results to suggest that climate tipping points, such as disintegration of the West Antarctic and Greenland Ice Sheets, do not result in significantly higher SC-CO<sub>2</sub> estimates. The commenter argues that the paper implies that some tipping points, such as the Atlantic Meridional Overturning Circulation, could actually mitigate climate impacts of warming temperatures. Similarly, the commenter expresses support for EPA's exclusion of extreme weather impacts from the model, writes that this decision is consistent with Lomborg (2020),<sup>42</sup> who the commenter argues "provides significant detail explaining that extreme weather events are not increasing due to climate change, but instead demonstrates that increasing costs and impacts from extreme weather are due to the increasing human population and development footprint primarily in coastal regions around the world." The commenter also notes that the *Nature*<sup>43</sup> article cited by EPA and Lomborg (2020)<sup>44</sup> share opinions on sea level rise, as EPA assigns only a small fraction of the SCC to sea level rise costs, and Lomborg agrees that the significantly increased annual coastal flooding costs associated with sea level rise will be managed through adaptive measures. To this point, the commenter recommends EPA cite Lomborg (2020).

Response A-3-1: EPA appreciates the commenters' feedback on the climate module. The FaIR model, developed by researchers at Oxford University, is one of the most widely used reduced complexity models used to generate projections of global temperature change, is open source, and was highlighted by the National Academies as a model that satisfies their recommendations for a near-term update of the climate module in SC-GHG estimation. However, EPA agrees that the climate module omits some potentially large-scale Earth system feedback effects (e.g., from tipping elements or 'tipping points') and that recent studies have started to make progress on incorporating more tipping points in the estimation of SC-GHG. In particular, Dietz et al. (2021)<sup>45</sup> have advanced the quantification of tipping elements to explicitly account for several important temperature feedbacks within the climate system. The EPA has expanded the discussion of Dietz et al. (2021) and their results in Section 3.2 of the Report to acknowledge significant advancements made in this area. The EPA will continue to follow progress in this line of research and look for opportunities to better reflect tipping elements and other Earth system

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<sup>41</sup> Dietz, Simon, James Rising, Thomas Stoerk, and Gernot Wagner (2021): "Economic impacts of tipping points in the climate system," *Proceedings of the National Academy of Sciences*, 118 (34) e2103081118.

<sup>42</sup> Lomborg, B., 2020. Welfare in the 21st century: Increasing development, reducing inequality, the impact of climate change, and the cost of climate policies. *Technological Forecasting and Social Change*, 156, p.119981.

<sup>43</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

<sup>44</sup> Lomborg, B., 2020. Welfare in the 21st century: Increasing development, reducing inequality, the impact of climate change, and the cost of climate policies. *Technological Forecasting and Social Change*, 156, p.119981.

<sup>45</sup> Dietz, Simon, James Rising, Thomas Stoerk, and Gernot Wagner (2021): "Economic impacts of tipping points in the climate system," *Proceedings of the National Academy of Sciences*, 118 (34) e2103081118.

feedback effects and to account for non-climate mediated GHG effects in future updates of the SC-GHG estimates. Throughout the report, EPA has expanded discussion about how the presented SC-GHG estimates likely underestimate the marginal damages from greenhouse gas pollution. EPA has especially expanded discussion in Section 3.2 "Omitted Damages and Other Modeling Limitations" including remarks and references on tipping elements.

EPA disagrees with commenter (2227-W. Energy Alliance) that the Dietz et al. (2021) results *support* the exclusion of tipping points in the climate module. As discussed in the Final Report, under their main specification Dietz et al. (2021) estimate that the inclusion of eight individual tipping points into the analysis increases the SC-CO<sub>2</sub> by approximately 25 percent. The authors additionally state that the distribution of these effects is highly right skewed, noting a 10 percent chance that the SC-CO<sub>2</sub> more than doubles. EPA does not agree with commenter's interpretation that these effects are insignificant. The authors further acknowledge, in both their published study and in their comments in this rulemaking summarized above, that research is still needed to incorporate other physical impacts from these feedbacks, such as precipitation and ecosystem impacts associated with passing a tipping point. For example, the authors note in their comment letter (2194-S. Dietz et al.) that a key missing damage channel related to the AMOC slowdown relates to changed precipitation patterns, which scientists believe would lead to additional rather than lowered damages (Liu et al. 2017)<sup>46</sup>.

The EPA also disagrees with commenter's (2227-W. Energy Alliance) recommendation to cite Lomborg (2020) as in agreement with the *Nature*<sup>47</sup> article cited in EPA's Report. EPA clarifies that the exclusion of extreme weather impacts in the SC-GHG estimates presented in EPA's Report is an omission due to data and modeling limitations in the ability to explicitly represent these impacts in both the climate module and the damages module used for SC-GHG estimation, not an explicit choice to exclude the potential impacts of extreme events due to insufficient scientific consensus about these events being impacted by climate change. Regarding historical trends, the IPCC AR6 chapter on extreme events states that, "Evidence of observed changes in extremes and their attribution to human influence (including greenhouse gas and aerosol emissions and land-use changes) has strengthened since AR5, in particular for extreme precipitation, droughts, tropical cyclones and compound extremes (including dry/hot events and fire weather)." Regarding future changes, the IPCC stated that "even relatively small incremental increases in global warming (+0.5°C) cause statistically significant changes in extremes on the global scale and for large regions (high confidence). In particular, this is the case for temperature extremes (very likely), the intensification of heavy precipitation (high confidence) including that associated with tropical cyclones (medium confidence), and the worsening of droughts in some regions (high confidence)."<sup>48</sup> Finally, EPA agrees with the commenter that explicit treatment of

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<sup>46</sup> Liu, W., Xie, S-P., and Zhu, J., 2017. Overlooked possibility of a collapsed Atlantic Meridional Overturning Circulation in warming climate. *Science Advances*, 3(1): e1601666.

<sup>47</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

<sup>48</sup> Intergovernmental Panel on Climate Change (IPCC). 2021. Seneviratne, S.I., X. Zhang, M. Adnan, W. Badi, C. Dereczynski, A. Di Luca, S. Ghosh, I. Iskandar, J. Kossin, S. Lewis, F. Otto, I. Pinto, M. Satoh, S.M. Vicente-Serrano, M. Wehner, and B. Zhou, 2021: Weather and Climate Extreme Events in a Changing Climate. In *Climate*

adaptation is important for estimating the damages from climate change, including in the category of sea level rise impacts. We have expanded the discussion of the adaptation assumptions in the Report, including the optimistic assumptions of the implementation of optimal, lowest-cost adaptation strategies with respect to sea level rise damages and highlight this as an important area for future research.

Comment: Commenter (2361-EPRI) provides several recommendations pertaining to the climate module. First, the commenter recommends that EPA revise the module to fully address NASEM recommendations, including undertaking NASEM performance tests. The commenter states “the module documentation should be enhanced to satisfy the transparency, scientific basis, and uncertainty consideration recommendations (NASEM Recommendation 2-2). The documentation should assess the literature they are using, provide methodological details, equations, and parameters, provide additional detailed results, and justify the methodological choices in that literature and associated with its integration into EPA’s overall framework, as well as justify detailed results. In addition, the module should provide spatially disaggregated climate information (and account for uncertainties) and evaluate climate model performance with respect to the specific experiments NASEM (2017) recommended (NASEM Recommendations 4-1, 4-2, and 4-5).”<sup>49</sup>

Second, the commenter argues that EPA should expand evaluation and comparison to justify the approach and better account for uncertainty. The commenter offers specific improvements for EPA’s temperature modeling, including expanding its comparison of the central tendencies of FaIR to MAGICC and Hector to include distributional comparisons and comparisons to other reduced complexity models, such as MIT Earth System Model; and representing the low end of the IPCC AR6 climate sensitivity distribution. The commenter disputes the plausibility of EPA’s temperature projection of as high as almost 8 degrees Celsius in 2300 as shown in Figure 2.2.2, stating, “Society is likely to respond and manage the climate before then.” The commenter argues that a pathway plausibility assessment would help to rule out such outcomes from consideration or assign even lower probabilities to them.

Third, the commenter recommends endogenizing non-GHG radiative forcing to address the current fixed forcing assumption’s inconsistency with the broad range of projected futures and to capture non-GHG forcing uncertainty in temperature projections. Finally, the commenter argues that EPA needs to provide additional methodological details and results pertaining to all the climate module recommendations above to facilitate a full assessment.

The commenter also encourages EPA to revisit the large emissions pulse size used to calculate the SC-GHG estimates and to discuss and assess non-linearity and choice justification. The commenter states that since the pulse sizes used for computing the social costs of methane and

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*Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press.  
[https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC\\_AR6\\_WGI\\_Chapter11.pdf](https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter11.pdf)

<sup>49</sup> National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press.  
<https://doi.org/10.17226/24651>.



nitrous oxide are currently unclear, greater transparency is needed on the size of the pulses used and the justification for implementing a large pulse. The commenter asks EPA to discuss “potential bias given non-linearities in both the climate and damage modules from deriving an average per ton SC-GHG result from implementing a large pulse.”

Response A-3-2: EPA disagrees that the climate module needs revision in order to fully address the NASEM near-term recommendations. FaIR 1.6.2 is a fitting model to serve as the basis for an updated climate module to address NASEM recommendations. In fact, NASEM specifically highlighted FaIR as a model which addressed their criteria: see the first paragraph of the section in Chapter 4 entitled, “An Illustrative Simple Earth System Model.”<sup>50</sup> FaIR is open source, and therefore meets NASEM recommendations for transparency. FaIR’s uncertainty calibration to IPCC assessed values of climate sensitivity and other parameters are documented in the SC-GHG report, and the IPCC also relied on FaIR for its own uncertainty analysis (see the IPCC AR6 WGI assessment in the Supplementary Information for Chapter 7).<sup>51</sup> With regard to the production of spatially disaggregated climate information, the NASEM Recommendation 4-5 begins, “To the extent needed by the damages module, the Interagency Working Group should use disaggregation methods...”. As described in Section 2.3 of the Report, all three of the approaches to damage function estimation use only GMST as an input to the global damage module. But as detailed in Section 2.3 of EPA’s Report (and further discussed in Section 3.2), the underlying damage studies incorporate various resolutions of regional climate, and therefore, it is not necessary for the climate module itself to produce such regionally disaggregated data. EPA has updated and added figures and surrounding discussion in Section 3.2 exploring modeling of regional population, temperature, sea level, and precipitation projections.

The commenter’s second recommendation is that EPA expand its evaluation and comparison to other climate models. The commenter highlights alleged differences between FaIR and MAGICC to justify this recommendation, claiming that MAGICC is a warmer model and providing a figure (the commenter’s Figure 5) to show comparisons between MAGICC and FaIR. The commenter claims that the source of Figure 5 is the IPCC database. However, this Figure is inconsistent with Table 7.SM.4 from the IPCC.<sup>52</sup> Since the commenter does not provide a more complete citation than “Source: IPCC database”, EPA is unable to determine more about this inconsistency. In Section 2.2 of the Report, EPA has expanded the discussion of the Reduced Complexity Model Intercomparison Project (RCMIP)<sup>53</sup> (Nicholls et al. 2020),<sup>54</sup>

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<sup>50</sup> National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24651>.

<sup>51</sup> IPCC AR6 WGI (2021). “Chapter 7: The Earth’s energy budget, climate feedbacks, 3 and climate sensitivity - Supplementary Material” [https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC\\_AR6\\_WGI\\_FGD\\_Chapter07\\_SM.pdf](https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FGD_Chapter07_SM.pdf)

<sup>52</sup> IPCC AR6 WGI (2021). “Chapter 7: The Earth’s energy budget, climate feedbacks, 3 and climate sensitivity - Supplementary Material” [https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC\\_AR6\\_WGI\\_FGD\\_Chapter07\\_SM.pdf](https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FGD_Chapter07_SM.pdf)

<sup>53</sup> See <https://www.rcmip.org/>.

<sup>54</sup> Nicholls Z., Meinshausen M., Lewis J., Gieseke R., Dommenges D., Dorheim K., Fan C., Fuglestad J.S., Gasser T., Golüke U., Goodwin P., Hartin C., Hope A.P., Kriegler E., Leach N.J., Marchegiani D., McBride L.A., Quilcaille Y., Rogelj J., Salawitch R.J., Samset B.H., Sandstad M., Shiklomanov A.N., Skeie R.B., Smith C.J., Smith S., Tanaka K., Tsutsui J., and Xie Z., 2020. Reduced Complexity Model Intercomparison Project Phase 1:

which compares all three models (FaIR, MAGICC, and Hector) against the Earth system models used by the IPCC.

The commenter also suggests that the temperature change scenarios in Figure 2.2.2 reaching almost 8°C in 2300 should be assigned lower probabilities or ruled out. EPA notes that the report methodology already does reflect the lower probability of the highest-temperature outcomes. In particular, Figure 2.2.2 is shaded to illustrate percentile ranges, and 8°C falls outside of the illustrated 1st to 99th percentile range. As discussed in EPA's Report, the distribution of projected global mean surface temperature in Figure 2.2.2 reflects uncertainty in both emissions and physical climate processes that are consistent with the latest projections coming out of the Sixth Assessment Report (IPCC 2021a)<sup>55</sup>.

The commenter further suggests that the reason for ruling out or lowering the probability weights of high-temperature outcomes is that "Society is likely to respond and manage the climate before then." EPA disagrees with ad hoc adjustments to the methodology, such as "ruling out" particular socioeconomic or climate scenarios based on heuristic judgements of "implausibility." The highest temperature scenarios are represented with lower probability as indicated by the percentile shading in EPA's report Figure 2.2.2, which is based upon the underlying draws of emissions scenarios and climate parameters. As detailed in EPA's Report, the RFF-SP emissions scenarios are based upon expert elicitations, taking into account the likelihood of future emissions mitigation policies and technological developments EPA has no scientific rationale for ignoring parts of the peer reviewed published emissions projections or adjusting the distributions on an ad hoc basis. In addition, as discussed in the Report, EPA's modeling does not yet account for many feedback effects, such as the impact of climate change damages on future emissions. The National Academies (2017) identified explicitly accounting for feedbacks between the damages and climate modules to the socioeconomic module as an important longer-term goal in the SC-GHG estimation process. EPA will continue to follow advances in the literature on this topic, consistent with the National Academies' recommendations regarding continued improvements. Such future research could further explore the likelihood of additional mitigation policy in the scenarios with the most adverse outcomes.

Regarding the commenter's recommendation to endogenize non-GHG radiative forcing in order to better reflect non-GHG forcing uncertainty in the temperature projections, EPA acknowledges that aerosol emissions uncertainty is not currently represented in the modeling and has introduced a discussion of the potential to further explore aerosols in Section 2 of the Final Report. However, while aerosol radiative forcing uncertainty is a large contributor to historical forcing uncertainty, recent research suggests it may not contribute as much to future uncertainty. A recent submitted paper, Sarofim et al. (2023),<sup>56</sup> used the "silicone" methodology to fill in

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introduction and evaluation of global-mean temperature response. *Geoscientific Model Development*, 13(11), pp.5175-5190.

<sup>55</sup> Intergovernmental Panel on Climate Change (IPCC). 2021a. *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. <https://www.ipcc.ch/report/ar6/wg1/>

<sup>56</sup> Sarofim, M., Smith, C., Malek, P., McDuffie, E., Hartin, C., & Lay, C. (2023). How high is high enough? A multi-million-member ensemble analysis of future climate scenarios and their relevance.

aerosols and minor GHGs for the RFF-SPs and find that there is a very modest impact as a result of including these substances because most of the underlying literature scenarios have similar reductions in far-future emissions of these substances. Similarly, Figure SPM-4<sup>57</sup> shows that in each of the five SSP scenarios, CO<sub>2</sub> uncertainty is the largest contributor to future climate uncertainty. EPA will continue to follow advances in the literature on these topics, consistent with the National Academies' recommendations regarding continued improvements.

Regarding the commenter's request for additional documentation and assessments, EPA disagrees with the commenter's suggestion that the discussion of methodology and results in the Draft Report was insufficient to facilitate a full assessment. Section 2.1 provides a detailed description of the climate module, including how the FaIR model compares to other reduced complexity climate models and IPCC assessments, and how it addressed the National Academies near term recommendations. In the Final Report, EPA has added discussion of additional details noted by the commenter, such as an explanation of how FaIR has a number of uncertain parameters that are chosen to be compatible with each other. The EPA has also added a new Appendix in the Final Report to summarize the treatment of uncertainty in each module, including the climate module. EPA notes again that FaIR 1.6.2 is open-source, and the parameter set is available online. The method used to generate the FaIR parameter ensemble yields a joint distribution of all parameters such that they are consistent with the historical observations and future model data against which the parameter set was calibrated. The full list of uncertain parameters and their quintile values for the FAIR v1.6.2 climate model is available in Supplementary Information Table 3 in Rennert et al. (2022).<sup>58</sup> Finally, in the Final Report, EPA has expanded the explanation of the emission pulse sizes used for the SC-GHG estimation. As discussed in Section 2, the pulse sizes used for the model runs were selected to be the smallest size that the climate system model will reasonably represent and where the damage functions are responding on the margin.

Comment: Commenter (2344-IER) argues that it is more important for regulatory impact analysis to describe temperature and sea level impact of the rule than to estimate SC-GHG as the latter is "abstract concept and one influenced by the technology we may or may not have when Captain James T. Kirk is born on March 22, 2233." The commenter recommends that EPA present the temperature and sea level rise impacts of the rule anywhere EPA reports the SC-GHG.

Response A-3-3: EPA disagrees that it is more important for RIAs to explain the temperature and sea level impact of a regulation than to report a monetized measure of the value of those physical changes to society. First, uncertainty about future technology is not a reason to favor reporting

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<sup>57</sup> Figure SPM.4 in IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, pp. 3–32, doi: 10.1017/9781009157896.001

<sup>58</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

physical impacts on temperature and sea level over monetized benefits to society that are calculated using SC-GHG estimates. The characteristics of future technologies will affect the SC-GHG through many of the same channels as they would affect future temperatures and sea levels. For example, future technologies will determine the emissions-intensity of the future economy. Second, a monetary measure of climate impacts provides a more comprehensive way to inform the public and policymakers of the climate benefits or disbenefits expected from a proposed action and its alternatives. Presenting the climate impacts of a proposed rule in only physical units (e.g., fractions of a degree of temperature change or centimeters of sea level rise) does not disclose or explain when and how society will be affected by those physical changes. EPA and OMB guidance recommends that an agency provide an assessment of the potential costs and benefits of all economically significant regulatory actions, and that this assessment include a monetization of benefits and costs to the extent feasible. The SC-GHG provides an aggregated measure of affected individuals' willingness to pay for reduced climate change impacts associated with policy actions that reduce GHG emissions and is, therefore, the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions.

## A.4 Damage Module

Comment: Commenters (2208-CCES et al., 2349-RFF, 2397-U.S. Climate Alliance, 2246-NRDC) provide supportive comments specific to the methodology that EPA employs in its damage module.

Commenter (2397-U.S. Climate Alliance) applauds EPA’s inclusion and utilization of updated estimated values for the SC-GHG in the Draft Report, expressing that they were informed by the latest science and will properly account for the societal costs of climate damages when crafting effective state and federal policies. Similarly, commenter (2208-CCES et al.) states that EPA’s methodology and damage valuations are consistent with those applied by a range of expert independent researchers. The commenter states that the Draft Report faithfully implements recommendations laid out by the National Academies of Sciences for updating the social cost of greenhouse gases and applies the latest available science to its estimates.<sup>59</sup> Specifically, the damage module addresses the need to “draw on recent scientific literature” and “extend far enough in the future” to capture all key climate impacts.

Commenter (2349-RFF) endorses EPA’s use of the Greenhouse Gas Impact Value Estimator, or GIVE model, a product of RFF and the University of California, Berkeley’s Social Cost of Carbon Initiative, highlighting its comprehensive nature. The commenter explains how the GIVE model modularizes and updates each of the four modules of SCC estimation and provides peer-reviewed scientific literature bolstering the various components of the model: (1) Long-run socioeconomic projections,<sup>60</sup> (2) Improved climate model,<sup>61,62,63</sup> (3) Updated damage functions,<sup>64,65,66</sup> and (4) Economic discounting.<sup>67</sup> The commenter concludes with the central estimates of SC-CO<sub>2</sub> or SC-CH<sub>4</sub> from the GIVE model and explains its critical usage in the EPA report, along with supplementation from the damage functions from the Data-Driven Spatial

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<sup>59</sup> National Academies of Sciences, Engineering, and Medicine. 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24651>.

<sup>60</sup> Rennert, K. et al. The Social Cost of Carbon: Advances in Long-Term Probabilistic Projections of Population, GDP, Emissions, and Discount Rates. Brook. Pap. Econ. Act. (2021).

<sup>61</sup> Smith, C. J. et al. FAIR v1.3: a simple emissions-based impulse response and carbon cycle model. Geosci. Model Dev. 11, 2273–2297 (2018).

<sup>62</sup> Forster, P. et al. The Earth’s energy budget, climate feedbacks, and climate sensitivity. In IPCC 2021. Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (eds. Masson-Delmotte, V. et al.) (Cambridge University Press, 2021).

<sup>63</sup> Wong, T. E. et al. BRICK v0.2, a simple, accessible, and transparent model framework for climate and regional sea-level projections. Geosci. Model Dev. 10, 2741–2760 (2017).

<sup>64</sup> Cromar, K. R. et al. Global health impacts for economic models of climate change: a systematic review and meta-analysis. Ann. Am. Thorac. Soc. 19, 1203–1212 (2022).

<sup>65</sup> Moore, F. C., Baldos, U., Hertel, T. & Diaz, D. B. New science of climate change impacts on agriculture implies higher social cost of carbon. Nat. Commun. 8, 1607 (2017); Clarke, L. et al. Effects of long-term climate change on global building energy expenditures. Energy Econ. 72, 667–677 (2018).

<sup>66</sup> Diaz, D. B. Estimating global damages from sea level rise with the Coastal Impact and Adaptation Model (CIAM). Clim. Change 137, 143–156 (2016).

<sup>67</sup> Newell, R. G., Pizer, W. A. & Prest, B. C. A Discounting Rule for the Social Cost of Carbon. J. Assoc. Environ. Resour. Econ. (2022a).

Climate Model by the Climate Impact Lab and an aggregate damage function developed in Howard and Sterner (2017).<sup>68</sup>

Commenter (2246-NRDC) expresses support for the use of three different methodologies to convert climate impacts into economic damages, including a meta-analysis of existing literature, that “taken together provide a more expansive view of the economic harms of climate change.”

Response A-4-1: EPA thanks the commenters for supportive comments on the damage module.

Comment: Multiple commenters (2208-CCES et al., 2398-Policy Integrity NYU, 2246-NRDC) expressed overall support of EPA’s damage module and recommend updating the damage functions as estimates become available, including adding feedback effects between modules when possible. Commenters (2410-CA AG et al., 2246-NRDC, 2398-Policy Integrity NYU, 2208-CCES et al., 2293-S.Holmes) underscore the importance of addressing omitted impact categories, and commenters (2398-Policy Integrity NYU, 2208-CCES et al.) state that these omitted damages result in conservative estimates of the SC-GHG.

Commenter (2410-CA AG et al.) encourages the modeling of wildfire health impacts and loss of culturally and historically significant assets. While EPA’s Draft Report lists wildfire damages and other damage categories as unquantified or partially quantified, it does not “evaluate their significance” or “indicate... which non-quantified effects are most important and why.” The commenter states that adding this kind of analysis, as called for in OMB Circular A-4 (2003), would greatly enhance the informative value of all future discussions of SC-GHG. The commenter specifies the importance of two specific unquantified damages: (1) health impacts from wildfires and (2) the loss of culturally and historically significant assets. The commenter highlights a study by the Union of Concerned Scientists that identified many historic sites and landmarks at risk from climate change.<sup>69</sup> The commenter recommends that EPA discuss significant omitted damages, including damages from wildfire, and damages to culturally and historically important resources, whenever EPA refers to the SC-GHG in rulemaking.

Commenter (2246-NRDC) also lists several omitted damages and the impact their omission has on EPA’s analysis. The commenter states that because health-related impacts are not monetized, EPA’s report is missing a substantial cost, and health-related damages linked to climate events should be included in future revisions of the SC-GHG. Similarly, the commenter states that omitting damages from climate change-induced wildfires, including market losses, non-market losses, and mortality costs, also biases the SC-GHG estimates downwards. Lastly, the commenter remarks that omitted environmental damages such as biodiversity impacts will have significant effects and recommends prioritizing their inclusion in the future.

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<sup>68</sup> Howard, P. H., & Sterner, T. Few and not so far between: a meta-analysis of climate damage estimates. *Environmental and Resource Economics*, (2017) 68(1), 197-225.

<sup>69</sup> Union of Concerned Scientists, *National Landmarks at Risk: How Rising Seas, Floods, and Wildfires Are Threatening the United States’ Most Cherished Historic Sites*, at 4–32, 36–40, 44 (2014).

Commenter (2398-Policy Integrity NYU) encourages EPA to more strongly emphasize that omitted impacts bias the damage estimates downwards and to take steps to address these omissions. The commenter notes that although EPA properly characterizes its climate-damage valuations as underestimates, it can do more to emphasize the point and take steps to address it. For one, the commenter states that the 2017 Howard and Sterner<sup>70</sup> damage function does not account for the “increased value of non-market goods and services due to their growing relative scarcity from climate and non-climate factors” and argues that this is another reason to further lower the discount rate as a way to implicitly account for relative prices. The commenter goes on to say that if EPA elects not to decrease the rate of discount rates for this reason, then the Agency should at least recognize discounting as an additional reason that the SC-GHG values presented in EPA’s report underestimate climate damages. The commenter recommends that EPA augment the impact specific damage functions (from DSCIM and GIVE) as relevant published studies become available. The commenter also suggests that as part of the damage function update process, EPA should conduct its own regular literature reviews to address omitted impacts using relevant published studies. As an example, the commenter recommends EPA use benefit-transfer methods to add the representation of labor productivity damages from DSCIM into the GIVE and Howard and Sterner based damage functions “in order to avoid excluding empirically established impacts. Then, when labor productivity is successfully addressed by one of the other two damage functions, EPA can adopt this alternative estimate, so as to benefit from independence in damage estimates.” The commenter also encourages EPA to incorporate tipping points into the damage function and provides examples of some methods to do so. Within this discussion, the commenter highlights that the recent Dietz et al (2021)<sup>71</sup> “analysis represents the most sophisticated analysis in the literature capturing multiple explicit tipping points, and is the ideal strategy that the EPA should adopt to integrate those damages into its valuations, as it avoids stylized representations of tipping points and their consequences.” As noted above, the commenter suggests that an alternative to explicitly modeling multiple tipping points and their interactions could be to adopt a reduced-form estimates of the damages from tipping points based on Dietz et al.’s results. The commenter acknowledges, however, that “this approach is less desirable than explicit modeling, as it is reliant on other modeling assumptions made by the authors that may be inconsistent with EPA’s model.” The commenter emphasizes that modeling omitted tipping points “would be a critical step toward the National Academies long-term goal of modeling feedback effects between the various IAM modules.” Regarding other omitted impacts, that commenter highlights several that should be included based on the availability of published studies with sufficient detail and the magnitude of potential impact, such as environmental services and biodiversity; air pollution due to rising heat, methane converting to ozone, and wildfires; inland flooding; and freshwater availability.

Additionally, commenter (2398-Policy Integrity NYU) provided comments on the specification of the Howard and Sterner based damage function used in the damage module. The commenter states that EPA “appropriately selects the Howard and Sterner (2017)<sup>72</sup> damage function, as it is

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<sup>70</sup> Howard, P. H., & Sterner, T. (2017). Few and not so far between: a meta-analysis of climate damage estimates. *Environmental and Resource Economics*, 68(1), 197-225.

<sup>71</sup> Dietz, S., van der Ploeg, F., Rezai, A. and Venmans, F., 2021a. Are economists getting climate dynamics right and does it matter? *Journal of the Association of Environmental and Resource Economists*, 8(5), pp.895-921.

<sup>72</sup> Howard, P.H. and Sterner, T., 2017. Few and not so far between: a meta-analysis of climate damage estimates. *Environmental and Resource Economics*, 68(1), pp.197-225.

the most up-to-date meta-regression estimate of global damage estimates for the Agency's purposes."<sup>73</sup> The commenter notes that EPA offers compelling reasons for this selection and applies it in an appropriate manner, but recommends that EPA also consider applying an alternative specification of the damage function from Howard and Sterner "rather than relating solely on their most conservative estimate." The commenter recommends that EPA adjust its selection to account for additional information in Howard and Sterner (2022)<sup>74</sup> to reflect updated information, including potential changes to the central estimate of non-catastrophic damages and its variance. Specifically, the commenter recommends that EPA consider using an alternative damage estimate that excludes damage estimates corresponding to temperature increase above 4 degrees Celsius, as the standard errors for estimates increase at that level, making damage estimates highly uncertain and speculative. The commenter highlights the need for EPA to (1) update the underlying dataset of Howard and Sterner as new global damage studies become available and (2) adopt the most up-to-date methodologies.

Commenter (2313-M. Plevin-Foust) describes the link between climate change and security, suggesting that the consequences of climate change, such as resources scarcity and climate migrants, can exacerbate global instability. The commenter's claim is bolstered by the fact that the Pentagon has ranked the climate emergency as the greatest threat to peace and global stability, as increased drought and hunger has the potential to lead to more wars and threats to democracies worldwide. The commenter states that the hotter and more unlivable the global South becomes, the more of the world and especially the U.S. will be overwhelmed with climate refugees. The commenter suggests that considering a higher social cost of carbon can help prevent the worst outcomes from occurring, keeping the U.S. safer as a result. The commenter suggests that modelling of physical impacts should include dangerous weather, smoke caused by forest fires, drought, species extinction, and pest-borne disease.

Commenter (2293-S. Holmes) discusses the ozone related health effects from methane emissions, notes the absence of tropospheric ozone figures in the SC-GHG Report's Table 3.2.1, and states that the Supplemental RIA did not monetize the ozone health effects from the methane emissions reductions expected from the proposed rule. The commenter acknowledged that the discussion of recent estimates from the literature that find ozone-related mortality benefits of CH<sub>4</sub> emissions reductions "to be \$800 to \$1,800 per metric ton of methane emissions" is useful, but "what would be more helpful at the state level, though, would be a set of clearly prescribed methane and other social cost of greenhouse gas cost valuations that can readily be applied to energy and environmental policy making and utility regulation."

Commenter (2208-CCES et al.) emphasizes that EPA's updated estimates exclude certain key climate damages and urges the agency to integrate reliable quantifications of these impacts as they emerge. The commenter states that EPA's updated social-cost valuations offer a reasoned approach to assessing climate impacts. The commenter acknowledges that EPA notes the existence of omitted climate damages within its Draft Report and correctly emphasizes in the Draft Update that its valuations likely undervalue the marginal damages from greenhouse gas

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<sup>73</sup> Howard, P. H., & Sterner, T. Few and not so far between: a meta-analysis of climate damage estimates. *Environmental and Resource Economics*, (2017) 68(1), 197-225.

<sup>74</sup> Peter H. Howard & Thomas Sterner, *Between Two Worlds: Methodological and Subjective Differences in Climate Impact Meta-Analyses* 12, 19 (Resources for the Future Working Paper 22-10, 2022).



pollution and emphasizes the damages and limitations that contribute to this potential undervaluation in a dedicated section of the report. The commenter also stresses that the Draft Report excludes numerous expected climate impacts, including diseases, ecosystem services, water impacts, and national security effects, among others. The commenter mentions that there are efforts outside EPA to quantify omitted impacts and suggests that EPA should integrate these quantifications once available. The commenter also highlights that while certain impacts can be valued economically, others that are harder to measure might always remain underestimated.

Response A-4-2: EPA thanks the commenters for the helpful suggestions regarding omitted damage categories. Consistent with OMB Circular A-4 guidance (2003 and 2023), the EPA acknowledges and discusses the numerous categories of climate impacts and associated damages that are either not yet incorporated in the SC-GHG analysis or only partially incorporated. These omissions are listed in Table 3.2.1, and the EPA has further expanded the discussion of omitted damages in the Final Report (e.g., in Section 3.2). This includes additional discussion of the damages from wildfire and highlighting the omission of damages to culturally and historically important resources, as requested by one commenter. One advantage of the modular framework recommended by the National Academies and adopted in the updated SC-GHG estimation is that future research on new or alternative damage functions can be incorporated into the damage module in a relatively straightforward way as they become available. The EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages from climate impacts and explore ways to better inform the public of the full range of GHG impacts.

EPA appreciates the comments made by commenter (2398-Policy Integrity NYU) regarding the choice of specification of the Howard and Sterner (2017) meta-analysis. As discussed in the Report, EPA focuses on a specification that includes estimates across the full range of temperature changes considered in the underlying studies, rather than specifications that are constrained to studies using lower temperatures and, then, extrapolate them to estimate damages at higher temperatures, because this approach is more consistent with the share of the projected temperature anomaly distribution exceeding 4°C and the temporal distribution of discounted damages over the course of the modeling period. EPA has further clarified in the Final Report that this choice of specification likely underestimates the benefits of GHG abatement. EPA has also expanded the discussion in the Final Report to recognize the updated Howard and Sterner (2022) working paper and other emerging meta-regression studies incorporating more recent global damage estimates. EPA will continue to follow the published literature in this area as the Agency looks for opportunities to improve damage functions in future updates of the SC-GHG.

One commenter highlighted that tropospheric ozone related benefits of CH<sub>4</sub> emissions reductions expected from the rule were not monetized in the Supplemental Proposal RIA. EPA notes that this impact is listed in Table 3.2.1 of the Report as ‘not yet incorporated’ in the updated SC-CH<sub>4</sub> estimates. EPA has expanded the discussion of this important omitted damage category in both the Report and in the final RIA. The Report and final RIA discusses the results of a newly published study by McDuffie et al. (2023),<sup>75</sup> who present recent estimates of the health risks

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<sup>75</sup> McDuffie, E.E., Sarofim, M.C., Raich, W., Jackson, M., Roman, H., Seltzer, K., Henderson, B.H., Shindell, D.T., Collins, M., Anderton, J. Barr, S., and Fann, N., 2023. The Social Cost of Ozone-Related Mortality Impacts From Methane Emissions. *Earth's Future*, 11(9), p.e2023EF003853.

associated with the methane-ozone impact mechanism. The authors use the same socioeconomic projections, mortality risk valuation, and discounting approach described in the Report and find the monetized increase in respiratory-related human mortality risk from the ozone produced from methane emissions in 2020 to be \$1,800 per ton of CH<sub>4</sub>. EPA will continue to look for opportunities to incorporate the ozone related impacts of CH<sub>4</sub> emissions in future updates to the SC-CH<sub>4</sub>.

EPA responds to the comments about further lowering the discount rate in part as a way to proxy for omitted damages in the Discounting Section of comments below.

Comment: Commenter (2361-EPRI) emphasizes the need for enhanced documentation of the module methodology to meet all the NASEM near-term recommendations. Specifically, commenter recommends that EPA provide discussion, assessment, and justification for differences in results across damage modules, sectoral SC-GHG distribution results, and results for other discount rates and years. The commenter cites issues of damage estimate comparability discussed by the IPCC WGII 2021 report<sup>76</sup> and the National Academies (2017). The commenter states that all NASEM recommendations should be followed, and inconsistencies and incoherent connections between modules should be resolved.

The commenter states that different methodologies (statistical, structural, and meta-analyses) have been used in the damages module, and that these methodological differences raise questions about whether the results are comparable and can be readily combined and treated as alternatives or instead should be viewed as different lines of evidence that need to be formally integrated with one informing and/or constraining the other. The commenter argues that DSCIM is based on statistical analyses, while GIVE is derived from structural analyses. The commenter adds that EPA should discuss the methodologies as presented in the literature of the models they are using, including DSCIM, and explain why agricultural impacts are a small part of DSCIM results, as compared to GIVE. The commenter recommends that EPA assess and discuss the methodological details in the literature that they are using.

The commenter recommends that EPA's damage module should consider more of the available literature to accurately estimate damages and account for uncertainty. The commenter states that EPA currently considers only a small fraction of the existing literature, despite "relevant alternatives globally and for individual damages categories." The commenter mentions that current sectoral damage approaches (DCSIM and GIVE) do not consider potential interactions between damage categories, which potentially lead to comparability issues in the damage module. The commenter presents figures showing examples of alternative global damage estimates from the literature, (e.g., Burke et al. 2015<sup>77</sup>) and some alternatives for individual damage categories (e.g., health damage estimates from a Bressler et al. study lacking a full

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<sup>76</sup> IPCC, 2021. Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3–32, doi:10.1017/9781009157896.001.

<sup>77</sup> Burke, M., Hsiang, S.M. and Miguel, E., 2015. Global non-linear effect of temperature on economic production. *Nature*, 527(7577), pp.235-239.

reference and crop yield damage estimates developed from Nelson et al. (2014)).<sup>78</sup> The commenter also states that EPA should “more fully incorporate current scientific knowledge to account for reasonable alternatives, reconcile lines of evidence, and improve uncertainty representation” and that models as well as their implementation should be consistent with the current body of scientific literature. The commenter also suggests including 1) equations, parameters, and examples regarding cross-module linkages and integration; 2) other assumptions, input data, equations, parameter values, uncertainty specifications from the literature used, and sources; and 3) additional intermediate and final results to enhance transparency. In addition, the commenter notes that any documentation should be self-contained. Additionally, the commenter highlights issues regarding spatial resolution, adaptation responses, statistical uncertainty, and integration with the socioeconomic module requiring transparent and explicit documentation. The commenter suggests that details are missing regarding how global and regional projections of GDP, population, global temperature, and sea level rise are integrated into each damage sector. The commenter recommends that EPA provide explicit descriptions and assessment of the variations in adaptation represented across damage modules and sectors, as well as a disaggregated total and incremental damage projection results by module and over time to improve transparency and facilitate assessment.

Commenter emphasizes the need for enhanced documentation of the module methodology to meet all the NASEM near-term recommendations. Specifically, commenter recommends that EPA provide discussion, assessment, and justification for differences in results across damage modules, sectoral SC-GHG distribution results, and results for other discount rates and years. The commenter cites issues of damage estimate comparability discussed by the IPCC WGII 2021 report<sup>79</sup> and the National Academies (2017). The commenter states that all NASEM recommendations should be followed, and inconsistencies and incoherent connections between modules should be resolved.

The commenter recommends presenting damage results without socioeconomic, climate, and SLR uncertainty in order to determine the damage-specific response and uncertainty representations. The commenter also suggests including detailed undiscounted damage results over time by country and category per projection and adding a discussion of consistency across the damage modules.

Response A-4-3: EPA thanks the commenter for their review of the damages module but disagrees with the commenter’s suggestion that the NASEM (2017) near-term recommendations have not been met. Section 5 and Table 5.1 in the Final Report describe how the methodology

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<sup>78</sup> Nelson, GC, H Valin, RD Sands, P Havlik, H Ahammadd, D Derynge, J Elliott, S Fujimori, T Hasegawa, E Heyhoe, P Kyle, M Von Lampe, H Lotze-Campen, D Mason d’Croza, H van Meijl, D van der Mensbrugghe, C Müller, A Popp, R Robertson, S Robinson, E Schmid, C Schmitz, A Tabeau, D Willenbockel, 2014. Climate change effects on agriculture: Economic responses to biophysical shocks. *Proceedings of the National Academy of Sciences of the United States of America* 111(9): 3274–3279.

<sup>79</sup> IPCC, 2021. Summary for Policymakers. In: *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3–32, doi:10.1017/9781009157896.001.

satisfies the NASEM near-term recommendations for this module. EPA disagrees that we do not address the “comparability” issue as mentioned by the commenter. Specifically, the NASEM (2017) report states: “The differences in methodologies and in scope create challenges for users trying to synthesize understanding of impacts or damages. For instance, structural and empirical methods are fundamentally different from one another and, as a consequence, they produce results that may not be directly comparable. These comparability and scope issues need to be addressed in some way when developing damage functions.” EPA provides a thorough discussion of combining different lines of evidence in Section 4.1 of the Report. As outlined in the Report, EPA set out to reflect the state of current understanding of climate damages in the published literature and, therefore, EPA believes the damage module reflects that there are different approaches to damage function estimation which result in different estimates. In response to the NASEM recommendation to update existing damage functions to reflect recent scientific literature, EPA adopted a suite of three updated damage functions (GIVE, DSCIM, and a meta-analysis), which together represent the major scientific lines of evidence on the economic impacts of climate change that are available, capture uncertainty, and, in the cases of GIVE and DSCIM, provide transparent bottom-up modeling that map Earth system changes to damages. The models’ spatially explicit and impact-specific modeling of relevant processes allows for improved understanding and transparency about mechanisms through which climate impacts are occurring and how each damage component contributes to the overall results, consistent with the NASEM recommendations. The damage functions in the GIVE model offer a direct implementation of the NASEM near-term recommendation to develop updated sectoral damage functions that are based on recently published work and reflective of the current state of knowledge about damages in each sector. Specifically, the National Academies noted that “[t]he literature on agriculture, mortality, coastal damages, and energy demand provide immediate opportunities to update the [models]” (National Academies 2017, p. 199), which are the four damage categories currently in GIVE. The EPA Report transparently describes each approach and state of the damage function literature (e.g., Section 2.3) and provides a clear, well-reasoned explanation for how these different lines of evidence were incorporated into the damage module (see e.g., Section 4.1).

EPA notes that development of more formal integration approaches to account for structural uncertainty across damage functions is an opportunity for improvement in future updates. One approach to integrating different lines of evidence would be at the stage of model estimation (e.g., structural uncertainty across damage modules). However, currently DSCIM is a stand-alone model with a spatial resolution of over 25k impact regions and requires complex estimation and large capacity computing power. Therefore, this type of integration with the other damage modules is not currently feasible as each independent model was created by independent research teams and include a single characterization of each impact category that was identified by the research teams as the best available for inclusion in each of the models. However, statistical uncertainty in impacts is accounted for parametrically in each of the impact categories when statistical uncertainty was available. Regarding differences in the DSCIM and GIVE agriculture damages, EPA has documented the differences between the two agricultural studies underlying each of the models in Tables 2.3.1 (DSCIM) and Table 2.3.2 (GIVE). Moreover, the differences in damages are the combined result of all the methodological differences between the DSCIM and GIVE models as described in Sections 2.3.1 and 2.3.2.

To provide additional transparency and understanding of how statistical uncertainty is incorporated within each of the damage modules, EPA has added Appendix A.8, along with Table A.8.1, that documents how uncertainty is addressed and captured within, and across, modules. Regarding interactions between the impact categories, EPA recognizes in the Report that the models do not yet account for potential interactions between them. This is explicitly discussed in Section 3.2 and outlined in Table 3.2.1 as an area for future development.

Regarding the commenter's request for documentation on the differences and similarities in adaptation responses across the damage modules, EPA notes that Section 3.2 of the Final Report contains a thorough documentation of the damage module and the methodological details of the damage categories included in DSCIM and GIVE. The methods used in the underlying studies are also summarized in Table 2.3.1 (DSCIM) and Table 2.3.2 (GIVE), including how they account for adaptation.

Regarding the commenter's suggestion to isolate the damage-specific uncertainty, EPA notes for the commenter that the inputs to the damage modules include uncertainties carried through from both the socioeconomic and climate modules, which compounds with the parametric uncertainty in the damage modules. Isolating the damage-specific uncertainty to the results as recommended by commenter would, in part, require choosing central sets of parameters for the upstream socioeconomic and climate modules to use as the baseline settings from which to interrogate damage function uncertainty. Because many of these inputs are probabilistic in nature (e.g., the RFF-SPs), this is not feasible within the current modeling framework and parameterization. The socioeconomic module uncertainty is represented as 10,000 equally-likely socioeconomic projections with no central setting or draw. Similarly, the jointly sampled parameter draws for the climate module do not have a central case.

To ensure transparency and to accommodate interest in alternative specifications and sensitivities, EPA has provided all source code, data, and documentation such that anyone in the public can access, freely, the necessary tools to explore the models. This is available, as listed in the Report and on EPA's SC-GHG website, at [github.com/USEPA/scghg](https://github.com/USEPA/scghg).

Comment: Some commenters (2231-R. Sohn, 2313-M. Plevin-Foust, 2246-NRDC, 2227-W. Energy Alliance, 3603-T. Lent) submitted comments pertaining to the "value of statistical life" (VSL) estimates used to value marginal mortality risk changes in the damages module.

Commenters (2231-R. Sohn, 2313-M. Plevin-Foust) express overall support for EPA's Supplemental Proposal but argue that it is morally indefensible to ultimately use different VSL values for citizens of different countries that result from adjusting VSL values using countries' per-capita GDP. Commenter (2313 Plevin-Foust) states that the importance and invaluableness of human life reinforces EPA's efforts to calculate the SCC. The commenters urge EPA to monetize changes in marginal mortality risk changes projected to occur in other countries using the same VSL values assigned to Americans even if such a change doubles the resulting SC-CO<sub>2</sub>. Commenter (2313-M. Plevin-Foust) argues that it is in the United States' best interest to do so for climate stability, global influence and security, and economic and health reasons. The commenter also notes that the social cost of carbon adopted by the U.S. will also likely be used by Canada and other nations.

Commenter (2246-NRDC) acknowledges that “economic theory indicates that to satisfy Kaldor-Hicks criterion WTP to VRR [value for mortality risk reduction] need to reflect the actual views of the target population”, “recognizes that the VRR should scale with per capita GDP to some extent”, and that the “scaling approach correctly implies that as nations grow wealthier in the future, their WTP for VRR would increase”. However, the commenter is concerned that it is unlikely that the assumed income elasticity of 1.0 is appropriate for VRR across all levels of GDP, and the commenter argues that “Developing a VRR for other nations is an ethical and political issue as well as an economic one. Assigning a very low VRR to the citizens of other nations politically signals a lack of concern for their health”. The commenter presents three feasible potential alternatives to EPA’s current approach: (1) using an equity-weighted approach to estimating SC-GHG, as described by Cromar et al.<sup>80</sup>; (2) applying a lower bound VRR for less affluent countries, such that if the benefits transfer approach used in the Draft Report results in a VRR less than the preset lower bound then the VRR would default to that lower bound; or (3) applying one U.S. VRR and one globally weighted VRR that “wouldn’t discriminate between the VRR of nations by GDP per capita”. The commenter notes that they are unaware of an existing method for setting the lower bound value under option 2, hence “EPA would have to work with experts to make a policy judgement to develop this value.”

Commenter (2227-W. Energy Alliance) argues for additional scrutiny of using the same approach for carcinogenic risk to assess climate change-related mortality risk. The commenter notes “WTP values used in the revised SC-CO<sub>2</sub> estimates are based on cancer risk reduction that one might be a beneficiary of in one’s own lifetime. EPA has now applied that concept to climate change risk reduction that are more likely to impacts non-U.S. citizens well outside the range of a current adult’s life span.” The commenter further notes the heterogeneity in risk aversion throughout the population. The commenter encourages EPA to further explain what value was used for the Statistical Value of a Life and the WTP values in the revised SC-CO<sub>2</sub> estimates.

Commenter (3603-T. Lent) objects to the use of VSL, suggesting that the formulation used by EPA in the Draft Report disproportionately values the lives of higher-income populations. The commenter argues that this leads to a perverse outcome in which “the current VSL formulation puts a higher value on lives of populations in which the individuals are statistically more likely to do more damage if they live longer”. As an alternative, the commenter recommends the agency evaluate the social costs of regulatory actions in terms of predicted life extension benefits. Commenter (2339-INGAA) argues that damage calculations erroneously seek to translate non-market effects, particularly human health impacts, or mortality risks, into dollar amounts. The commenter asserts that such quantification is a non-scientific value judgment.

Response A-4-4: In Appendix A.7 of the Report, EPA has provided a thorough discussion of the methodology underlying the estimates of willingness to pay for mortality risk changes – a number inaptly termed the “Value of Statistical Life” (VSL) – that are applied in the SC-GHG estimation process. As explained in OMB Circular A-4 (2003), “these terms refer to the measurement of willingness to pay for reductions in only small risks of premature death. They have no application to an identifiable individual or to very large reductions in individual risks.

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<sup>80</sup> Kevin Cromar, Peter Howard, Valeri N. Vásquez, David Anthoff, Health Impacts of Climate Change as Contained in Economic Models Estimating the Social Cost of Carbon Dioxide (2021); <https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2021GH000405>.

They do not suggest that any individual's life can be expressed in monetary terms” (OMB 2003). Circular A-4 (2023) contains similar guidance (OMB 2023).

As discussed in Appendix A.7, the benefits transfer approach used for monetizing expected marginal mortality risk changes occurring in other countries based on a positive income elasticity is consistent with the approach used in the default version of the damage functions and published studies used in the report, other academic literature, advice given to the IWG by experts, and other prominent domestic and international guidance documents that speak to international mortality risk reduction valuation. EPA disagrees with the commenters who recommend that the Agency develop a new alternative benefits transfer approach. Assigning a uniform VSL globally based on the global average would value the marginal mortality risk changes to residents of lower income countries higher than their willingness to pay and value mortality risk changes to higher income countries less than their willingness to pay. Using a globally uniform VSL approach based on the global average would also lead to inconsistencies for climate-driven U.S. mortality risk changes and how EPA values U.S. mortality risks from other causes in benefit-cost analysis (BCA). An implicit weighted social welfare function is also present in one commenter’s suggestion of a potential approach that sets a lower bound VSL for less affluent countries. Indeed, the commenter acknowledges that they are unaware of an existing method for setting such a lower bound value and hence the Agency would have to “make a policy judgement” to develop this value.

EPA disagrees with the commenters who object to the use of any monetized measure of the value of mortality risk reductions, or other non-market effects, on the grounds that it is a “non-scientific value judgment.” As explained in Appendix A.7 of the Report, for damage categories that involve non-market impacts (commodities or services not traded in the market, like changes in mortality risks) there is no readily observed price information and there are challenges in capturing the value of something as precious as changes in life expectancy. However, economists have developed a robust literature to infer values for these non-market commodities using methods that are consistent with the theoretical underpinnings of EPA’s BCA. EPA has relied on estimates from the published literature to monetize changes in mortality risks expected from policy options in regulatory BCA since the 1980s. For more discussion of the development of this methodology, see Appendix A.7 of the Final Report and EPA’s Guidelines for Preparing Economic Analyses.<sup>81</sup>

Comment: Two commenters (2464-Heal and Bressler, 2428-API) argue that using PPP-adjusted VSL estimates is not compatible with the Kaldor Hicks criterion.

Commenter (2464-G. Heal and D. Bressler) applaud the EPA for their “excellent work” and commend the Agency for making numerous significant improvements in the updated SC-GHG estimates compared to the IWG SC-GHG estimates. Then, among a “few constructive criticisms”, the commenter argues that an assertion made in the Draft Report about current EPA BCA practice being consistent with the Kaldor-Hicks potential compensation principle is incorrect. The commenter highlights two key points of contention: 1) the valuation of premature mortality risk changes in EPA RIAs and 2) the use of purchasing power parity (PPP)-adjusted

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<sup>81</sup> U.S. Environmental Protection Agency (EPA), 2010. Guidelines for Preparing Economic Analyses. EPA-240-R-10-001. <https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses>

income in the development of the SC-GHG estimates. Regarding the first point, the commenter states that EPA's practice of assigning a single uniform value to monetize mortality risk changes to U.S. populations is inconsistent with the Kaldor-Hicks principle, and results in the BCA being closer to welfare weighting than a Kaldor-Hicks consistent BCA. Regarding the second point, the commenter argues that the use of PPP-adjusted dollars undermines the potential compensation principle and recommends that the benefits and costs be measured in a number representing an actual unit of exchange over which transfers can occur, such as money at market exchange rates. The commenter suggests that EPA use a Negishi-Weighted social welfare function instead of strictly adhering to the Kaldor-Hicks potential compensation test, as the use of the social welfare functions is argued to better represent observed preferences.

Commenter (2428-API) questions EPA's usage of PPP-based projections in the SC-GHG framework. Referencing a study,<sup>82</sup> the commenter argues that using PPP is incompatible with a pure Kaldor-Hicks approach. Specifically, the authors provide an example in which a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. The commenter urges EPA to explain how using PPP-adjusted dollars aligns with the federal government's overall approach to cost-benefit analysis and suggests that EPA should clarify its rationale and address any potential inconsistencies with the established principles of cost-benefit analysis.

Response A-4-5: EPA understands the concerns about using PPP-adjusted income in the development of the SC-GHG estimates, but there is no clear consensus in the economic literature on whether the market exchange rate or PPP should be used to adjust the GDP value. The choice involves a tradeoff between consistency with the potential compensation test of the Kaldor-Hicks criterion and reflecting the actual preferences in the country under consideration. Using the PPP takes into account the different price levels and different baskets of goods consumed across countries, and it more accurately describes relative standards of living across countries. PPP adjustment is also the standard approach in the literature (Hammitt and Robinson 2011<sup>83</sup>, Nordhaus 2017a<sup>84</sup>, 2017b<sup>85</sup>, Robinson, et al. 2019a<sup>86</sup>) and it is the same approach used in the damage function estimates in GIVE and DSCIM. EPA believes that this is currently the best practice for benefit transfer of VSL estimates, but we recognize that this is an approximation. EPA has added discussion of this issue in Appendix A.7 of the Final Report.

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<sup>82</sup> Bressler R., and Geoffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research.

<sup>83</sup> Hammitt, J.K. and Robinson, L.A., 2011. The income elasticity of the value per statistical life: transferring estimates between high and low income populations. *Journal of Benefit-Cost Analysis*, 2(1).

<sup>84</sup> Nordhaus, W.D., 2017a. *Evolution of Assessments of the Economics of Global Warming: Changes in the DICE model, 1992–2017* (No. w23319). National Bureau of Economic Research.

<sup>85</sup> Nordhaus, W.D., 2017b. Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences*, 114(7), pp.1518-1523.

<sup>86</sup> Robinson, L.A., Hammitt, J.K., Cecchini, M., Chalkidou, K., Claxton, K., Cropper, M., Eozenou, P.H., de Ferranti, D., Deolalikar, A.B., Guanais, F., and D.T. Jamison. 2019a. *Reference case guidelines for benefit-cost analysis in global health and development*. Cambridge, MA: Harvard University.



Comment: A few commenters (2227-W. Energy Alliance, 2445-J.K. Davis, 2428-API) opined on the damage functions used for particular impact categories (such as agriculture) and the degree to which the damage estimates could be considered “conservative”.

Commenter (2227-W. Energy Alliance) recommends that EPA revisit their damage functions, which suggest adverse agricultural impacts associated with higher temperatures, to accurately reflect the agricultural benefits some warming can have on crops. The commenter states that historical damage functions indicate that a certain degree of warming benefits certain types of agriculture, yet the damage function used by EPA suggests otherwise. The commenter also highlights the potential for significant adaptation through agricultural science and crop engineering. Furthermore, the commenter advises EPA to acknowledge the significant increase in agricultural damage in the revised global SC-CO<sub>2</sub> estimates due to the new agricultural damage function used in the GIVE model. The commenter recommends that EPA addresses the uncertainty and lack of clarity associated with the damage function used in the *Nature*<sup>87</sup> article. The commenter also argues that EPA's conclusion that the new SC-CO<sub>2</sub> estimates are an underestimation of future climate change impacts is not well-supported. As support for this assertion, the commenter notes that the GIVE damage function used by EPA indicates that climate change impacts to U.S. citizens are lower than those impacts suggested by a global SC-CO<sub>2</sub> value and are almost entirely a result from the contribution of the Temperature Mortality damage function. The commenter also states that Temperature Mortality has not been a significant factor in estimating SC-CO<sub>2</sub> in the past, but now constitutes half of the latest estimates, warranting further scrutiny and verification.

Commenter (2445-J.K. Davis) similarly expressed concerns that EPA's SC-GHG draft report does not sufficiently account for the potential benefits of greenhouse gases, such as enhanced photosynthesis from increased CO<sub>2</sub> levels and that cold weather deaths would decrease.

Commenter (2428-API) expresses that EPA should provide more support for its claim that its damage estimates are conservative due to non-quantified damages and other model limitations, because these assertions could potentially bias the IWG's process. Furthermore, the SC-GHG estimate of marginal damages in the report is likely to be an underestimation because there are multiple categories of damages that are not represented in the report. The commenter asserts that EPA should list and explain the range of possible options and how the Agency's approach represents the conservative choices reflected in the report. The commenter emphasizes that mortality-related impacts are significant in two sectoral damage functions. The commenter cites a research paper<sup>88</sup> and an IPCC report<sup>89</sup> that suggest the temperature-mortality response function differs by age, particular among individuals over the age of sixty-five. To account for such differences, the commenter recommends that EPA impart heterogeneity across age brackets when the agency conducts analyses. The commenter adds that the temperature-mortality function will likely change for a given location depending on adaptation measures. The commenter

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<sup>87</sup> "Comprehensive evidence implies a higher social cost of CO<sub>2</sub>", Rennert et al., *Nature*, Vol 610, Oct. 27, 2022.

<sup>88</sup> Carleton, T., Jina, A., Delgado, M., Greenstone, M., Houser, T., Hsiang, S., Hultgren, A., Kopp, R.E., McCusker, K.E., Nath, I. and Rising, J., 2022. Valuing the global mortality consequences of climate change accounting for adaptation costs and benefits. *The Quarterly Journal of Economics*, 137(4), pp.2037-2105

<sup>89</sup> Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In *Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC*, Chapter 16.

recommends future projections of the temperature-mortality function to account for potential adaptation to temperature change, considering various factors such as regional climate and socioeconomic status, to improve estimations. The commenter is critical of EPA's SC-GHG model because it uses damage functions at the subnational and/or sectoral level, but there is no discussion explaining why other damage functions, particularly those produced by structural economy-wide models, were excluded. The commenter calls for EPA to identify all possible damage function approaches and discuss their relative merits and shortcomings to provide stakeholders with a clear understanding of the selected approach. The commenter also calls for clear and apparent justification from EPA for the significant increase in the new SC-CO<sub>2</sub> estimates.

Response A-4-6: EPA has included a thorough discussion of the impact categories underlying each of the damage modules in section 2.3.1 for DSCIM and 2.3.2 for GIVE. These outline the net impacts estimated for categories such as the agricultural sector. As mentioned in the Report, the “The agriculture damage function component of GIVE follows Moore et al. (2017)<sup>90</sup>. It is derived using (1) a meta-analysis of over 1,000 published temperature-yield response estimates from 55 unique studies, and (2) an open-source computable general equilibrium (CGE) model that estimates the welfare consequences (as equivalent variation) of climate-induced productivity changes, accounting for adjustments in agricultural markets including trade patterns, consumption, and production. The productivity changes (for maize, rice, wheat, and soybeans) are based on biophysical crop impacts documented in the literature. Productivity impacts include both within-crop adaptations (e.g., varietal and planting date changes) as well as CO<sub>2</sub> fertilization using estimates of the size of these effects from the meta-analysis.” That is, the concerns raised by the commenter are fully addressed in the study underlying the agriculture damage function in GIVE.

With respect to the assertion that EPA has overestimated damages, EPA has documented many reasons for the SC-GHG estimates are likely to be a partial accounting of climate change impacts and likely underestimate the marginal benefits of GHG abatement (e.g., see Section 3.2). Additionally, regarding GIVE model-based results, Rennert et al. (2022b)<sup>91</sup> “expect that, in total, the future inclusion of additional damage sectors and tipping elements is likely to raise the estimates of the SC-CO<sub>2</sub>, and that therefore the estimates from the present study are likely best viewed as conservative.” EPA notes for the commenter that while all the near-term NAS recommendations have been met, Section 3.2 provides a thorough discussion of opportunities for future improvements. For example, although the damage functions applied in this report offer an improved accounting of adaptation and its costs, the modeled estimates employ optimistic assumptions about adaptation decisions in the estimation of coastal damages in GIVE and DSCIM.

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<sup>90</sup> Moore, F.C., Baldos, U., Hertel, T., and D.B. Diaz., 2017. New science of climate change impacts on agriculture implies higher social cost of carbon. *Nature Communications*, 8(1), pp.1-9.

<sup>91</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

The damage functions capture multiple net damage pathways that can be broadly divided into market and non-market pathways. Some net economic damages are experienced through markets, such as changes in net agricultural productivity, net energy expenditures, and property damage from increased flood risk. Examples of net damages experienced through the nonmarket pathways include changes in net mortality rates and changes in ecosystem services, including those provided by biodiversity.

Comment: Commenter (2417-Save LBI) argues that it is incorrect to present a permanent dollar social benefit based on a project's carbon emission reduction when it comes to sea level rise. The commenter suggests that EPA should not use the cost per ton numbers to quantify the environmental benefit of such projects. The commenter recommends that EPA make several revisions, including explaining the time delays between emission reductions and actual sea level rise reductions, creating a new carbon cost factor without the sea level rise element for cost-benefit analyses, and clarifying how the model's dollar benefit can be attributed to a state.

Response A-4-7: EPA would like to clarify for the commenter that the SC-GHG, as estimated in the Report, does, in fact, account for complex dynamics of environmental and socioeconomic conditions. Moreover, "The SC-GHG is the monetary value of the future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year" (Executive Summary of the Report). To estimate the SC-GHG for a given year  $t$ , the models are run twice – first as a baseline using exogenous trajectories of GHG emissions, and second with an additional pulse of GHG emissions in year  $t$ . After recalculating the temperature effects and damages expected in all years beyond  $t$  resulting from the adjusted path of emissions, the streams of marginal damages (i.e., the difference in damages in every year  $t + n$  between the baseline and adjusted model) are discounted to a present value in the discounting module. In this way, the model is capturing the value of having less sea level rise in year  $t + 1$ ,  $t + 2$ , and so on, relative to a world without the additional ton of GHG emissions. Regarding the appropriate use of the SC-GHG in benefit-cost analyses and accounting for global impacts, EPA refers the commenter to Section 1.3 and Section 4.2 of the Report.

## A.5 Discounting Module

Comment: Several commenters (2208-CCES et al., 2246-NRDC, 2410-CA AG et al., 2397-Climate Alliance, 3658-PolicyInteractive, 2349-RFF, 2398-Policy Integrity NYU, 2183-M. Freeman et al.) provided supportive feedback on the discounting module used in EPA's External Review Draft.

Commenters express support for EPA's updated discounting methodologies, particularly the transition to lower near-term discount rates than used in previous SC-GHG estimates. Commenters (2349-RFF, 2398-Policy Integrity NYU, 2183-M. Freeman et al.) affirm that EPA's discounting methodology and choice of near-term rates used have broad support from the academic literature.

Commenter (2208-CCES et al.) states that EPA uses an appropriate range of discount rates and encourages EPA to provide further justification of its discounting approach through regulatory practices and precedents, including EPA's past decisions on ozone protection<sup>92</sup> and the Clean Air Mercury Rule.<sup>93</sup> The commenter suggests that EPA emphasize its prior recommendation under the George W. Bush administration<sup>94</sup> of using lower discount rates for assessing climate damages. The commenter highlights the strong support of EPA's declining discounting rate approach in the economics literature. The commenter also notes that OMB's Circular A-4 (2003) guidance to intergenerational discounting offers strong support for EPA's declining-rate approach and explicitly endorses the use of lower discount rates for long-term effects such as climate change.

Commenter (2246-NRDC) notes the improvements regarding EPA's use of dynamic discount rates and argues that it is better able to address uncertainty in future economic growth. The commenter remarks that the Ramsey formula accounts for the fact that consumption discount rates would change based on changing economic conditions (lower discount rates are applied when economic growth is lower and vice versa). The commenter also states that EPA's choice of discount rates (1.5%, 2%, and 2.5%) are appropriate but argues that these values are conservative. The commenter further highlights other improvements to the discounting module including the incorporation of the relationship between discount rates and economic growth. Similarly, commenter (2410-CA AG et al.) applauds EPA's Draft Report and the use of dynamic discount rates with near-term rates of 1.5%, 2%, and 2.5% and argue that the 1.5% rate is most appropriate.

Commenter (2397-Climate Alliance) agrees that EPA's discounting methodology uses an appropriate range of discount rates. Similarly, commenter (3658-PolicyInteractive) expresses

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<sup>92</sup> Protection of Stratospheric Ozone, 53 Fed. Reg. 30,566, 30,569 (Aug. 12, 1988); Protection of Stratospheric Ozone; Labeling, 58 Fed. Reg. 8136, 8162–63 (Feb. 11, 1993); Protection of Stratospheric Ozone; Refrigerant Recycling; Substitute Refrigerants, 69 Fed. Reg. 11946, 11975 (Mar. 12, 2004).

<sup>93</sup> Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28,606, 28,642 (May 18, 2005). This rule was later vacated by the D.C. Circuit on grounds unrelated to the discount rate. *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).

<sup>94</sup> Regulating Greenhouse Gas Emissions Under the Clean Air Act, 73 Fed. Reg. 44,354, 44,416, 44,446 (July 30, 2008); Technical Support Document on Benefits of Reducing GHG Emissions (2008).

support for EPA's SC-GHG estimates and states that the discount rate should be no higher than 2.5 percent, citing the February 2021 IWG TSD.<sup>95</sup>

Commenter (2349-RFF) supports EPA's updated dynamic discounting approach and particularly endorses the change in the central discount rate from 3% to 2%. The commenter notes that the updated discounting methodology is well-supported by peer-reviewed economic literature and essential for capturing risk accurately. The commenter affirms that the shadow price of capital (SPC) approach is the correct and "analytically preferred method" for addressing concerns that regulatory costs may displace investment. The commenter discourages the use of a 7% discount rate based on investment returns. The commenter cites recent research<sup>96,97,98</sup> which demonstrates that the use of the 7 percent rate is "generally deeply flawed, especially when impacts are long-lived, such as in the case of climate change." The commenter urges analysts to adopt the SPC approach as laid out in recent literature.

Commenter (2398-Policy Integrity NYU) states that "both discount rate experts and climate experts consistently select a central discount rate of 2% (or lower when considering relative prices) as appropriate in inter-generational contexts, including in the climate context."

Commenter (2183-M. Freeman et al.) focuses their comment primarily on the dynamic discounting approach that EPA employed and states that the discounting methods used to calculate the SCC, including the central real social discount rate of approximately 2%, have strong independent support from the academic literature.

Response A-5-1: Thank you for the supportive comments.

Comment: Commenters (2208-CCES et al., 2398-Policy Integrity NYU) acknowledge the improvements in EPA's discounting methodology and advocate for further reductions in discount rates. The commenters argue that omitted damages result in a discount rate schedule that is biased upward. The commenters also note that consideration of relative prices of non-market goods support a lower discount rate.

Commenter (2208-CCES et al.) acknowledges that in the Draft Update, EPA has applied a reasonable range of discount rates which align with economic evidence, theory, and consensus. Despite the strengths recognized, the commenter highlights that the short-term discount rates used by EPA in the Draft Report are conservative, suggesting that evidence supports a range of 0.5% to 2.5% with a central estimate of approximately 1.5%. The commenter additionally addresses the connection between omitted impacts and the discount rate and suggests that unaccounted-for damages not only directly lead to an underestimation of the SC-GHG but also

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<sup>95</sup> Technical support Document: Social Cost of Carbon, February 2021. Council of Economic Advisors, Council of Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, (and 10 additional agencies).

<sup>96</sup> Li, Q. and Pizer, W.A. Use of the consumption discount rate for public policy over the distant future. *Journal of Environmental Economics and Management*, (2021) 107, p.102428

<sup>97</sup> Pizer, W.A. A Shadow-Price-of-Capital Approach to Harmonize Discounting for Greenhouse Gases in Broader Benefit-Cost Analyses. (2021). [https://media.rff.org/documents/OMB-2021-0006-0059\\_attachment\\_1.pdf](https://media.rff.org/documents/OMB-2021-0006-0059_attachment_1.pdf)

<sup>98</sup> Newell, R. G., Pizer, W. A. & Prest, B. C. The Shadow Price of Capital: Accounting for Capital Displacement in Benefit-Cost Analysis. *Resources for the Future*

indirectly via the discount rate through an overestimated economic growth rate. The commenter emphasizes that omitted impacts can affect the SC-CO<sub>2</sub> due to their influence on the variability of per-capita consumption growth rate and suggests a potential solution would be to adopt a lower discount rate range. The commenter recommended that if EPA does not decrease its range of discount rates, as recommended above, it should at least incorporate the arguments from that section into its dedicated discussion of reasons that the Draft Update's climate-damage valuations are likely underestimates.

Commenter (2398-Policy Integrity NYU) also urges EPA take steps to address omitted impacts, such as lowering the discount rates or noting that discounting contributes to underestimating damages. The commenter offers a mathematical argument that the presence of omitted damages not only results in an underestimate of the SC-GHG itself but additionally results in the use of an upwardly biased discount rate that works to indirectly lower estimates of the SC-GHG through the discounting methodology.

Commenters (2208-CCES et al., 2398-Policy Integrity NYU) urge EPA to consider relative prices of non-market goods in the discounting module. Commenter (2208-CCES et al.) notes that “[t]his is important, as damage functions have historically failed to account for the increased value of non-market goods and services due to their growing relative scarcity from climate and non-climate factors”. The commenters note that the experts surveyed in Drupp et al. (2018)<sup>99</sup> that explicitly accounted for relative prices supported a lower discount rate in the range of 0% to 2% with a central estimate of 1%. The commenter notes that “[r]elative prices can be implicitly captured by adjusting the social discount rate downward”.

Response A-5-2: As described in detail in the report, EPA assessed numerous lines of evidence calibrating the discount rate module including, historical real rates of returns, empirical studies of equilibrium real interest rates, future projections of real interest rates, and surveys of economists and technical experts. While singular lines of evidence may point to slightly higher or lower rates, looking across this wide body of evidence, EPA finds broad support for a near-term discount rate in the range of 1.5% to 2.5% with a central focus on 2.0%. Furthermore, as described in detail in the report, EPA finds broad support in the economic literature and in the National Academies recommendations for using the Ramsey formula to endogenize a dynamic discount rate schedule consistent the other modules used to estimate the SC-GHG.

EPA appreciates that, in some cases, if omitted damages were able to be included in the model, the endogenously determined risk adjusted discount rate schedule could be lower than what is currently included in the modeling. However, this result depends on the nature of the omitted damages and the correlation with economic growth. Since the quantitative effect on the dynamic discount rate schedule will depend on the specifics of the omitted damages, making precise exogenous adjustments to the discount rate to account for these effects would be challenging. Similarly, EPA appreciates the point that willingness to pay for non-market goods can vary over time as preferences and their availability changes. The damages module accounts for changes in willingness to pay overtime as preferences change based on key factors, such as income. However, EPA does not currently find sufficient support for calibrating specific quantitative

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<sup>99</sup> Drupp, M.A., Freeman, M.C., Groom, B. and Nesje, F., 2018. Discounting disentangled. *American Economic Journal: Economic Policy*, 10(4), pp.109-134.

adjustments to the discount rate to account for potentially omitted factors like changes in the relative scarcity of non-market goods over time. However, EPA looks forward to advances in the scientific literature of climate change that will allow for increased inclusion of currently omitted damages and improve the characterization of changes in willingness to pay over time, at which point, any impact on the dynamic discount rate schedule can be appropriately accounted for endogenously within the modeling framework. This approach will ensure that the impacts on the discount rate are consistent with the best available evidence on damages and consistent with the other components of the modeling.

Comment: Commenters (2253-OCT, 2208-CCES et al., 2410-CA AG et al.) acknowledge the significant improvements in EPA’s discounting methodology and advocate for further reductions in discount rates due to concerns regarding intergenerational equity.

Commenters (2253-OCT) acknowledges the improvements made by EPA’s Draft Report regarding the choice of lower near-term discount rates. The commenter argues that the use of discount rates (1.5%, 2%, and 2.5%) in the SC-GHG Report undervalues the benefits of climate action for children and future generations. The commenters suggest eliminating all estimates derived from these “constitutionally and ethically indefensible” discount rates. The commenter instead argues for incorporating discount rates that account for intergenerational equity and requiring the Agency to use constitutionally compliant discount rates of zero or near-zero percent. The commenter also raises concerns about equating personal and societal level consumption behavior preferences.

Commenter (2208-CCES et al.) notes that EPA’s approach to discounting resonates with the Working Group’s prior acknowledgment that rates of “2 percent and lower are warranted for intergenerational impacts.” The commenter highlights that Circular A-4 (2003)’s recommendation for additional analysis using a lower but positive discount rate for impacts with intergenerational effects. The commenter argues that relying solely on market-based data for discount rates ignores intergenerational equity.

Commenter (2410-CA AG et al.) applauds EPA for its use of near-term discount rates (1.5%, 2%, and 2.5%). The commenter cites research that support a long-term discount rate of no higher than 2 percent.<sup>100,101,102</sup> The commenter further advocates for the use of the estimates with a 1.5 percent discount rate because these estimates have a near-zero pure rate of time preference and

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<sup>100</sup> See Att. 23, Tamma Carleton, et al., Updating the United States Government’s Social Cost of Carbon, Energy Policy Institute at the University of Chicago, Working Paper No. 2021-04, at 23 (Jan. 2021), available at [https://epic.uchicago.edu/wpcontent/uploads/2021/01/BFI\\_WP\\_202104\\_Final.pdf](https://epic.uchicago.edu/wpcontent/uploads/2021/01/BFI_WP_202104_Final.pdf)

<sup>101</sup> The Use of the Social Cost of Carbon in the Federal Proposal “Safer Affordable Fuel-Efficiency (SAFE) Vehicles Rule,” (attached to comments of California Air Resources Board on EPA Docket No. EPA-HQ-OAR-2017-0355), Maximilian Auffhammer, Oct. 24, 2018, at 12

<sup>102</sup> Att. 36, Council of Economic Advisers, Discounting for Public Policy: Theory and Recent Evidence on the Merits of

Updating the Discount Rate, Issue Brief, at 3 (Jan. 2017), available at [https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701\\_cea\\_discounting\\_issue\\_brief.pdf](https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf). 176 EPA-HQ-O

echoes EPA's statement that Ramsey (1928)<sup>103</sup> argued that it is ethically indefensible to apply a positive pure rate of time preference when considering intergenerational contexts.

Response A-5-3: EPA notes that the 1.5%, 2%, and 2.5% rates used in the report, and to which the commenters refer, are the near-term discount rates. EPA did not use a constant discount rate over the modeling time horizon and therefore the near-term discount rates do not reflect the discount rates used for intergenerational impacts. The discount rate in future years is determined by the Ramsey formula consistent with economic theory and socioeconomic scenarios used in the modeling. As noted in the report, the Ramsey formula describes the consumption discount rate as a function that explicitly reflects: (1) preferences for utility in one period relative to utility in a later period (called the "pure rate of time preference"); and (2) the value of additional consumption as income changes. With respect to the pure rate of time preference, the calibrated values used by EPA (0.01%, 0.20%, and 0.46%), and presented in Table 2.4.2, are within the ranges of value used in peer-reviewed literature. The vast majority of papers in the climate change literature adopt values in the range of 0% to 2% per year, with most studies in the lower end of the range (IPCC 2014a<sup>104</sup>). The selection of rates on the lower end of that range tend to emerge from ethical concerns. Some have argued that to use any value other than 0 would unjustly discriminate against future generations (e.g., Arrow et al. 1995<sup>105</sup>, Stern 2006<sup>106</sup>). When Drupp et al. (2018)<sup>107</sup> surveyed economists about the most appropriate values for the pure rate of time preference the experts' responses had a median (mean) value of 0.5 (1.1) percent, and a mode value of 0. However, even under the case of intergenerational neutrality, a small positive pure rate of time preference may be appropriate to account for the probability of unforeseen cataclysmic events (Stern 2006).<sup>108</sup> Furthermore, it has been argued that very small values could be associated with an unreasonable rate of optimal savings (Arrow et al. 1995). As such, EPA finds that its calibrated values are within the range of values used in the peer reviewed literature, including those that are based on a prescriptive approach, and that no further adjustment to the pure rate of time preference is warranted. The second component of the Ramsey formula accounts for the value of additional consumption as income changes. This component of the discount rate specification explicitly accounts for intergenerational equity by ensuring that the relative impact of damages accounts for difference in economic wellbeing. The central parameter in defining this effect within the Ramsey formula is the elasticity of marginal utility with respect to consumption. As discussed in the report, the calibrated values of this parameter used by EPA are also within the ranges of values used in the peer-reviewed literature.

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<sup>103</sup> Ramsey, F.P., 1928. A mathematical theory of saving. *The economic journal*, 38(152), pp.543-559.

<sup>104</sup> Intergovernmental Panel on Climate Change (IPCC). 2014a. *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC [https://www.ipcc.ch/site/assets/uploads/2018/05/SYR\\_AR5\\_FINAL\\_full\\_wcover.pdf](https://www.ipcc.ch/site/assets/uploads/2018/05/SYR_AR5_FINAL_full_wcover.pdf)

<sup>105</sup> Arrow, K., Cline, W.R., Maler, K.G., Munasinghe, M., Squitieri, R., Stiglitz, J.E., 1995. Intertemporal equity, discounting, and economic efficiency. *Climate Change –995 - Economic and Social Dimensions of Climate Change. Contribution of Working Group III to the Second Assessment Report of the IPCC*, pp.125-144.

<sup>106</sup> Stern, N., 2006. *The economics of climate change: Stern Review*. Cambridge University Press, 712 pp.

<sup>107</sup> Drupp, M.A., Freeman, M.C., Groom, B. and Nesje, F., 2018. Discounting disentangled. *American Economic Journal: Economic Policy*, 10(4), pp.109-34.

<sup>108</sup> Stern (2006) assumes a pure rate of time preference of 0.1%. This reflects a 91% probability of the human race surviving 100 years.



Comment: Commenters (2398-Policy Integrity NYU, 2183-M. Freeman et al.) express overall support for updates made to EPA’s discounting methodology but seek clarifications and highlight potential areas of improvement.

Commenter (2398-Policy Integrity NYU) requests that EPA clearly specify its extended Ramsey equation and the underlying parameters and argues that “[t]his transparency will enable the public, including other federal and state agencies, to better understand the assumptions underlying the certainty-equivalent social cost of greenhouse gases.” The commenter further argues that a lack of understanding may prevent other entities from adopting these estimates and apply them to contexts with different risk profiles. The commenter notes that Figure 2.4.1 in EPA’s Draft Report “shows only the ‘certainty-equivalent risk-free discount rate’, omitting the risk premium term, implies that EPA never displays the explicit discount rate in full”. The commenter requests that EPA provide the implicit climate beta schedule and the risk premium parameter/value and explain the derivation of these values.

Commenter (2183-M. Freeman et al.) provides general support for EPA’s discounting methodology but presents some technical recommendations. The commenter notes that Newell, Pizer, and Prest (2022)<sup>109</sup> present the same Ramsey equation as equation 2.4.1 in the EPA report and observe that uncertainty in economic growth implies that the discount rate is also a random variable. The commenter states that there are two equivalent ways to express the SCC: 1) one in which the expectation is first taken over time and has the interpretation of dynamic discounting, and 2) one in which the expectation is first taken over simulation and has the interpretation of risk-adjusted discounting. The commenter elaborates that describing the discount rate as used in the Draft Report’s equation 2.4.1 as a “dynamic discounting environment” is potentially misleading and suggests that EPA refer to this approach as “risk-adjusted”. The commenter’s rationale is that it is difficult to place policy interpretations on the simulation-specific values,  $SCC_s$ , generated from taking the expectation over time first. The commenter notes that  $SCC_s$  only has the interpretation of a simulation-specific SCC under highly restricted assumptions regarding how growth uncertainty is resolved. Instead,  $SCC_s$  represents “a perfect hindsight value that EPA wishes, at time  $t = T$ , that it had enacted at time  $t = 0$  contingent on state  $s$  being the actual path the economy takes”. The commenter argues that this is inconsistent with how growth uncertainty resolves under the stochastic process of Müller, Stock, and Watson (2022).<sup>110</sup> The commenter further notes that summary statistics other than the mean of the SCC and the discount rate therefore require further explanation in the EPA report. The commenter argues that these values are real numbers and not stochastic variables and do not have 95% confidence intervals or other summary statistics associated with stochastic variables. The commenter notes that EPA correctly focuses on the mean estimate of the SCC and recommends that EPA further clarify the purpose and interpretation of other summary statistics presented in the report (e.g., median, 95<sup>th</sup> percentile). The commenter recommends that EPA focus on a single central estimate for the SCC and clarify the purpose of presenting the SCC estimates based on short-term rates of 1.5% and 2.5%.

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<sup>109</sup> Newell, R.G., Pizer, W.A. and Prest, B.C., 2022. A discounting rule for the social cost of carbon. *Journal of the Association of Environmental and Resource Economists*, 9(5), pp.1017-1046.

<sup>110</sup> Müller, U.K., Stock, J.H. and Watson, M.W., 2022. An econometric model of international growth dynamics for long-horizon forecasting. *Review of Economics and Statistics*, 104(5), pp.857-876.

Commenter (2183-M. Freeman et al.) also presents concerns related to the calibration of the Ramsey parameters. The commenter notes that they are unaware of previous research that demonstrates that the three models that EPA uses in its analysis (Ramsey (1928)<sup>111</sup>, Bauer and Rudebusch (2023)<sup>112</sup>, and Müller, Stock, and Watson (2022)<sup>113</sup>) are theoretically consistent with each other. Therefore, the commenter argues that EPA would benefit from giving reassurance to the theoretical consistency of estimating parameters ( $\rho$  and  $\eta$ ) using these three models as inputs.

Response A-5-4: EPA agrees with commenter (2398-Policy Integrity NYU) that transparency is important, and in the Report, EPA has provided highly detailed information regarding the process for calibrating the discount rate and the resulting discount rate schedule. Each of the 10,000 draws in the Monte Carlo simulation has a dynamic discount rate schedule based on the calibrated Ramsey parameters and the annual growth rate for that trial. Figure 2.4.1 in the Report presents percentiles and means of the distribution of this dynamic discount rate. This summarizes the actual 10,000 discount rate schedules used by EPA to discount marginal damages. The certainty-equivalent discount rate presented in Figure 2.4.1 in the Report is the single, time-averaged discount rate that produces the same discount factor for any given year as the expectation of the distribution of stochastic discount factors used in the modeling. An alternative approach suggested by the commentor (2183-M. Freeman et al.) would be to use a risk-adjusted rate to discount the marginal damages across all Monte Carlo trials. The commentor noted that these two approaches are numerically equivalent in terms of estimating the SC-GHG. However, this alternative approach would require accounting for the correlation between marginal damages and consumption growth (Prest 2023)<sup>114</sup>. Therefore, EPA chose to discount the marginal damages for each trial separately using the trial-specific discount rate schedule based on the Ramsey equation. Figure 2.4.1 presents the rates used by EPA, and Figure 3.1.1 presents the distribution of the discounted marginal damages per metric ton of CO<sub>2</sub> for 2030 emissions. To provide further transparency, EPA has provided the implied climate beta for three damage modules separately and for all damage modules combined in Appendix A.4 of the Final Report. Providing the risk premia for the three models is more difficult, primarily because the discounting in DSCIM is conducted in a high-computing environment, but Prest (2023)<sup>115</sup> calculates the risk premia for the GIVE damage module, which is also provided in Appendix A.4.

EPA understands the perspective of commenter (2183-M. Freeman et al.) but prefers the use of “dynamic discounting” to draw a clear distinction between the discounting approach used in this report and the constant discounting approach used in previous estimates of the SC-GHG used by EPA. However, EPA has included additional details on the discounting methodology in

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<sup>111</sup> Ramsey, F.P., 1928. A mathematical theory of saving. *The economic journal*, 38(152), pp.543-559.

<sup>112</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>113</sup> Müller, U.K., Stock, J.H. and Watson, M.W., 2022. An econometric model of international growth dynamics for long-horizon forecasting. *Review of Economics and Statistics*, 104(5), pp.857-876.

<sup>114</sup> Prest, B.C., 2023. Disentangling the Roles of Growth Uncertainty, Discounting, and the Climate Beta on the Social Cost of Carbon. Resources for the Future Working Paper 23-41.

<sup>115</sup> Prest, B.C., 2023. Disentangling the Roles of Growth Uncertainty, Discounting, and the Climate Beta on the Social Cost of Carbon. Resources for the Future Working Paper 23-41.

Appendix A.4 of the final report to highlight that the discounting approach used also accounts for consumption risk as the commenter describes.

EPA appreciates the concern about interpreting the simulation-specific values,  $SCC_s$ , and correctly characterizing the distributions shown in the report. While EPA believes that characterizing the uncertainty surrounding the SC-GHG estimates is important, the title of Figure 3.1.1 and other figures in the appendix have been changed to “Distribution of the Discounted Marginal Damages” to clarify the information being presented is distinct from a distribution of SC-GHG estimates.

In calibrating the Ramsey parameters, EPA followed the peer-reviewed work of Newell et al. (2022)<sup>116</sup>, which uses the empirical work of Bauer and Rudebusch (2023)<sup>117</sup> and Müller, Stock, and Watson (2022)<sup>118</sup> in a single framework to calibrate the parameters. In their peer-reviewed work, Rennert et al. (2022a<sup>119</sup>, 2022b<sup>120</sup>) apply these calibrated parameters to the Ramsey formula for estimating the SC-GHG using the RFF-SPs and EPA applies a consistent approach in its modeling. As noted in EPA’s SC-GHG Report, the Ramsey formula, while widely used in the economics literature and based on economic theory, is an approximation to highly complex real-world processes. As such, using empirical data to calibrate the parameters of the model can result in some approximation error as is always the case with structural economic models that seek to distill the economic connections that are of first order importance but are unable to represent every detail of the economy. EPA will continue to follow the literature on discounting and best practices for calibrating approaches to empirical data.

Comment: Commenters (2398-Policy Integrity NYU, 2183-M. Freeman et al., 2208-CCES et al) provide suggestions for addressing new research on the climate beta.

Commenter (2398-Policy Integrity NYU) discusses the implications for the omission of climate damage categories and tipping points for EPA’s discounting methodology. Specifically, the commenter argues that these omissions greatly decrease the per-capita consumption variance and therefore, produces an overly strong correlation between global GDP and climate damages. The commenter argues that this leads to a climate beta that is too high. In addition, the commenter argues that if climate damages impact economic growth, then this would result in lower the climate beta. The commenter urges EPA to give a more thorough discussion of the climate beta and illustrate that the insurance premium can be split into two terms (insurance and scale effects)

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<sup>116</sup> Newell, R.G., Pizer, W.A. and Prest, B.C., 2022. A Discounting Rule for the Social Cost of Carbon. *Journal of the Association of Environmental and Resource Economists*, 9(5), pp. 1017-1046.

<sup>117</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>118</sup> Müller, U.K., Stock, J.H. and Watson, M.W., 2022. An Econometric Model of International Growth Dynamics for Long-Horizon Forecasting. *Review of Economics and Statistics*, 104(5), pp.857-876.

<sup>119</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity*. Fall 2021, pp.223-305.

<sup>120</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

following Lemoine (2021).<sup>121</sup> The commenter argues that this may reduce the debate over the climate beta because these two independent effects are commonly confounded.

The commenter (2398-Policy Integrity NYU) also suggests that EPA conduct a sensitivity analysis over the climate beta and set the central value equal to zero but notes that this may be challenging given EPA's modular approach. The commenter notes considerable uncertainties around the value of the climate beta and argues that the climate beta is considerably lower than one. The commenter cites research<sup>122</sup> which shows that experts generally prefer lower discount rates for climate projects potentially because climate projects are viewed as less risky than infrastructure investments. The commenter further argues that it is a "strong possibility that EPA's implicit estimate of the climate beta exceeds the actual climate beta in the real world". The commenter argues that the continued use of the consumption-based Capital Asset Pricing Model (CCAPM) ensures that the impact of this potential bias is limited. Lastly, the commenter provides a mathematical argument that the value of the climate beta can theoretically be either positive or negative.

Commenter (2183-M. Freeman et al.) argues that implied climate beta assumed by EPA's model is close to one due to the fact that per-capita consumption growth is broadly proportional to the monetized flow of damages. The commenter recommends setting the beta value to zero, on the basis that empirical evidence is only beginning to emerge and that the value of one used by EPA is at the high end of the range in recent academic findings. The commenter cites recent research<sup>123,124</sup> that offer support for a default assumption that project risk is independent of future economic growth. The commenter notes that correlation structure between economic growth and damages in EPA's report is typical of other Integrated Assessment Models and questions whether this correlation structure reflects the best available empirical evidence. The commenter argues that revising the estimate of the climate beta will have an unclear effect on the SCC. Finally, the commenter reiterates that "the strongest argument for climate change mitigation may rely on the prevention of tipping points or other climate-related catastrophes" and that "such benefits are not captured by the near linear relationship between damages and growth in the EPA report, or where risk premia are calculated using covariances in equation 2.5.2".

Commenter (2208-CCES et al.) explains that omitted impacts reduce consumption growth variability and strengthen the correlation between global GDP and climate damages (increasing the "climate beta"). The commenter also states that including environmental and social tipping points decreases the climate beta by introducing non-linearities into the climate-economic system. A suggested solution is to consider a lower discount rate range.

Response A-5-5: In EPA's modeling, the climate beta is not a choice variable that analysts specify exogenously. EPA's modular approach, based on the recommendations of the National

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<sup>121</sup> Lemoine, D., 2021. The climate risk premium: how uncertainty affects the social cost of carbon. *Journal of the Association of Environmental and Resource Economists*, 8(1), pp.27-57.

<sup>122</sup> Gollier, C., van der Ploeg, R., & Zheng, J. (2023). The discounting premium puzzle: survey evidence from professional economists. *Working Paper*.

<sup>123</sup> Howard, P. and J.A. Schwartz (2022). "Valuing the future: legal and economic considerations for updating discount rates", *Yale Journal on Regulation*, 39(2), 595-657.

<sup>124</sup> Stroebel, J. and J. Wurgler (2021), "What do you think about climate finance?", *Journal of Financial Economics*, 142, 487-498.

Academies, uses the state-of-the-science information on socioeconomic, climate change, damages, discounting, and uncertainty, where feasible, to estimate the SC-GHG in a consistent manner. This process ensures that any risk adjustment to the SC-GHG estimates is internally consistent and based on the scientific information available. Therefore, there is no need to exogenously specify a climate beta value using estimates from the literature or other heuristic arguments as recommended by some public commenters.

For transparency and clarity in the assumptions used in the SC-GHG estimation, EPA updated the Report with a discussion of the climate beta in Appendix A.4 and the reported the climate beta implied by the discounting approach. EPA agrees that the incorporation of risk adjustments in estimates of the SC-GHG is an important area for new research, acknowledges the arguments made by the commenters that a climate beta of one is on the high end of values noted in some recent studies, and will follow this research closely in further iterations of the SC-GHG. EPA appreciates the citations from the commenters which highlight the discussion in the literature over the sign and magnitude of the climate beta. The limitations highlighted in Appendix A.4 present key gaps in the current literature and opportunities for further study. EPA will continue to follow the scientific literature on tipping points, omitted damages, and adaptation and plans to incorporate advances into future SC-GHG estimates, as feasible and appropriate. As such advances allow for more effects to be directly incorporated into the SC-GHG modeling, the endogenous risk adjustments will reflect the impact of those updates on the variance of consumption and the value of the climate beta implicit in the estimates.

Comment: Commenters (2253-OCT, 2311-Heal et al., 2183-M. Freeman et al.) question EPA's focus on a descriptive approach to discounting. An opposing view is presented by commenter (2339-INGAA), who argues that EPA's discounting approach relies on normative and unscientific judgements.

Commenter (2253-OCT) argues that "descriptive methodologies incorporate faulty assumptions that are unlikely to hold in a climate-ravaged world as well as implicit value judgments that indefensibly ignore fundamental considerations of intergenerational equity and children's fundamental rights."

Commenter (2311-Heal et al.) suggests that the selection of discount rates is a "social choice problem" and argues that an ideal approach to discounting is unlikely to exist due to irreconcilable differences in views. The commenter proposes addressing the ethical questions associated with discounting directly rather than relying on a simplistic empirical analysis. The commenter argues that EPA's purely descriptive approach is needlessly limited and notes that much of the considerations for intergenerational discounting are normative in nature.

Commenter (2183-M. Freeman et al.) argues that the positive approach to discounting in the report may leave the methods open to scrutiny and suggest that the intergenerational discount rate should balance positive and normative considerations. The commenter also states that the "EPA report would benefit from giving reassurance that the ways in which the risk premium is implicitly determined through the dynamic discounting approach is consistent with its broader positive philosophy of discounting." The commenter discusses the equity premium puzzle and notes that financial market risk premia would be underestimated when using the CCAPM. The

commenter notes “if the climate beta is indeed almost one, then CCAPM estimates are much lower than the values that would be derived from a purely positive estimate of the climate risk premium.” Therefore, the commenter argues that the “theoretical framework for estimating the risk premium, together with future proposed extensions, are more naturally interpreted as being normative.” Commenter (2183-M. Freeman et al.) shares their subjective opinion that using a high market-inferred risk premium in the intergenerational context is inappropriate but notes that they take a more neutral stance of positive vs. normative considerations. The commenter further notes that the Ramsey formula was developed under a normative framework, which does not change even if the parameters are calibrated using positive approaches. The commenter argues that the EPA Report would benefit from providing reassurance regarding the internal theoretical consistency of estimating positive parameters from Equation 5 in Newell, Pizer, Prest (2022).<sup>125</sup>

A divergent view is presented by commenter (2339-INGAA). The commenter argues that EPA’s discounting approach is unscientific and relies on normative assumptions. The commenter cites Fleurbaey et al. (2019)<sup>126</sup>, which argues that there are ethical decisions regarding the use of a utilitarian social welfare function and the conclusion that societal values can be determined by individual behavior, and the National Academies Report<sup>127</sup>, which states that the Ramsey parameters are not observable and require an ethical judgement.

Response A-5-6: Regardless of the theoretical approach used to derive the discount rate(s), there remain inherent conceptual and practical difficulties of adequately capturing consumption trade-offs over many decades or even centuries. While EPA relies on the descriptive approach for selecting specific discount rates based on observed preferences for temporal tradeoffs of consumption, the EPA is aware of the normative dimensions of both the debate over discounting in the intergenerational context and the consequences of selecting one discount rate over another. However, the EPA’s analysis relies primarily on the descriptive approach to inform the choice of a discount rate for SC-GHG estimation, consistent with the rationale outlined in IWG TSDs (e.g., IWG 2010<sup>128</sup>, 2021<sup>129</sup>) and EPA’s economic analysis guidelines (EPA 2010)<sup>130</sup>. With a recognition of its limitations, the IWG found this approach to be the most defensible and transparent given its consistency with both the standard contemporary theoretical foundations of benefit-cost analysis and the approach recommended by OMB’s existing guidance. In implementing this approach, EPA calibrates the  $\rho$  and  $\eta$  parameters of the Ramsey formula

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<sup>125</sup> Newell, R.G., Pizer, W.A. and Prest, B.C., 2022. A discounting rule for the social cost of carbon. *Journal of the Association of Environmental and Resource Economists*, 9(5), pp.1017-1046.

<sup>126</sup> Fleurbaey et al., The Social Cost of Carbon: Valuing Inequality, Risk, and Population for Climate Policy, 102 *Monist* 84, 90, 95-96 (2019)

<sup>127</sup> National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24651>.

<sup>128</sup> Interagency Working Group on Social Cost of Carbon (IWG). 2010 (February). *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*. United States Government. [https://www.epa.gov/sites/default/files/2016-12/documents/scc\\_tsd\\_2010.pdf](https://www.epa.gov/sites/default/files/2016-12/documents/scc_tsd_2010.pdf)

<sup>129</sup> Interagency Working Group on Social Cost of Carbon (IWG). 2021 (February). *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990*. United States Government. [https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument\\_SocialCostofCarbonMethaneNitrousOxide.pdf](https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf)

<sup>130</sup> U.S. Environmental Protection Agency (EPA), 2010. *Guidelines for Preparing Economic Analyses*. EPA-240-R-10-001. <https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses>.

following the Newell et al. (2022) calibration approach, as applied in Rennert et al. (2022a, 2022b). Under this approach, the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate path matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2020<sup>131</sup>, 2023<sup>132</sup>) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest based on multiple lines of evidence as to the near-term consumptions interest rate. This approach is consistent with the National Academies (2017) recommendation that the parameters in the Ramsey formula be chosen in a manner “consistent with theory and evidence and that produce certainty-equivalent discount rates consistent, over the next several decades, with consumption rates of interest.” The calibrated Ramsey parameters are also within the ranges of values of  $\rho$  and  $\eta$  used in the peer-reviewed literature, including many studies that state their parameter choices are based on prescriptive reasoning.

EPA appreciates the comments regarding the equity premium puzzle and the limitations of the CCAPM framework. However, the approach used within the CCAPM framework is conducted in a positive fashion. As commenter (2183-M. Freeman et al.) noted, the risk premium is implicitly determined through the dynamic discounting approach, and this approach is consistent with standard discounting approaches (Cochrane 2005<sup>133</sup> Asset Pricing).

Comment: Commenter (2239-A. Fraas et al.) presents concerns over EPA’s use of a declining certainty-equivalent discount rate and argues that this generates intertemporal inconsistencies.

Commenter (2239-A. Fraas et al.) argues that “it is unwise to completely abandon constant discounting and rely entirely on benefit estimates that assume a declining rate.” The commenter notes that while the use of declining discount rates is accepted, some use of constant discounting could avoid temporal inconsistencies. The commenter states that within-generation and intergenerational inconsistencies have the potential to arise when a declining discount rate is employed over extended periods of time and references Viscusi (2022)<sup>134</sup>. The commenter argues that this is because such a rate reflects the present generation’s perspective, potentially misrepresenting the preferences and priorities of future generations. The commenter argues that future generations will likely live longer, and a declining discount rate would place a greater weight on benefits in the latter part of the generation. The commenter highlights that “the future generations may prefer a different trajectory of benefits that is more front-loaded within that generation” and cautions against underestimating benefits early in life for future generations. The commenter refers to similar reasoning presented by Birdsall and Steer (1993)<sup>135</sup> and Wildavsky (1988).<sup>136</sup> The commenter states that EPA should not only rely on benefit estimates that assume a declining rate, as some analyses should maintain a constant discount rate. The commenter notes

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<sup>131</sup> Bauer, M.D. and Rudebusch, G.D., 2020. Interest rates under falling stars. *American Economic Review*, 110(5), pp.1316-54.

<sup>132</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>133</sup> Cochrane, J., 2009. *Asset pricing: Revised edition*. Princeton university press.

<sup>134</sup> Viscusi, W.K. 2022. The social discount rate: Legal and philosophical underpinnings, SSRN 4083202, forthcoming in *Annual Review of Financial Economics*, 2023.

<sup>135</sup> Birdsall, N., and Steer, A. 1993. Act now on global warming-but don't cook the books. *Finance and Development* 30(1): 6.

<sup>136</sup> Wildavsky, A. B. 1988. *Searching for Safety* (Vol. 10). Transaction Publishers.

that EPA does not discuss the implications of increases in longevity for the applicability of the Ramsey rule.

Response A-5-7: The use of the Ramsey formula provides internal consistency within the modeling between the socio-economic scenarios and the discount rate. With uncertainty in the per capita consumption growth rate, the Ramsey discount rate becomes a dynamic parameter within the modeling framework that reflects how uncertainty about future conditions has implications for how future impacts are valued. Gollier (2014)<sup>137</sup> showed that when there is uncertainty in future consumption growth, the distribution of discount rates defined by the Ramsey formula will have a certainty-equivalent risk-free discount rate path that declines over time, under standard assumptions about individual preferences. As noted by the commenter, use of a dynamic discount based on the Ramsey formula is consistent with accepted practice in the economics literature. The declining certainty-equivalent discount rate implied by the Ramsey formula is also consistent with the empirical literature on discount rates under uncertainty (e.g., Newell and Pizer 2003<sup>138</sup>, Bauer and Rudebusch 2023<sup>139</sup>). Therefore, use of a constant discount rate would be inconsistent with the empirical literature on discount rates under uncertainty and would fail to provide internal consistency within the modeling between socio-economic scenarios and the discount rate as recommended by the National Academies and has been applied extensive in the economics literature estimating the SC-GHG.

EPA recognizes that in some implementations a declining discount rate could imply an intertemporal inconsistency in the preferences of society if consumption growth were modeled deterministically or if a declining discount rate schedule were specified exogenously. However, EPA models consumption growth stochastically, and the declining certainty equivalent discount rate used in the EPA Report is generated endogenously using the Ramsey formula. In the Monte Carlo analysis, scenarios with high consumption growth are discounted at a higher rate than scenarios with lower consumption growth. Because of the non-linearity of the discount factor, the lower discount rate will have a greater impact on the certainty equivalent rate as time increases, leading to the declining certainty equivalent rate. As detailed in the report, this is consistent with the empirical literature and best practices for estimating the SC-GHG. Furthermore, this approach does not lead to temporal inconsistencies in preferences because the calibrated Ramsey parameters ( $\eta$  and  $\rho$ ), which reflect social preferences, are held constant. While EPA acknowledges that transferring these calibrated estimates into the future may result in an approximation error with respect to the preferences of future generations, the Agency is unaware of any peer-reviewed scientific studies that attempt to forecast changes in the Ramsey parameters due to changes in life expectancy.

Comment: Two commenters (2239-A. Fraas et al., 2344-IER) question the applicability of the Ramsey rule. Commenter (2239-A. Fraas et al.) raises concerns about the applicability of the Ramsey rule because health improvements, particularly improvements in longevity, may be as

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<sup>137</sup> Gollier, C., 2014. Discounting and growth. *American Economic Review*, 104(5), pp.534-537.

<sup>138</sup> Newell, R.G. and Pizer, W.A., 2003. Discounting the distant future: how much do uncertain rates increase valuations? *Journal of environmental economics and management*, 46(1), pp.52-71.

<sup>139</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.



valuable as consumption gains and cites several research papers<sup>140,141</sup> to support this. The commenter also argues that “[t]he rapidly changing composition of consumption over time itself raises utility, a fact ignored in the Ramsey formulation”. The commenter argues that the Ramsey formula is based on an outdated view of economic growth and cites research on human capital generation.<sup>142,143</sup> The commenter argues that EPA needs to address the broader question of how endogenous growth, improvements in health and longevity, and increasing consumption efficiency over time affect the choice of the social discount rate for climate control policy before committing to the use of the Ramsey formula.

Commenter (2344-IER) expresses that the Ramsey equation is a “logically flawed approach” because several inputs into the Ramsey equation are not observable, including the pure rate of time preference and the income elasticity of utility, and aggregating these values presents serious conceptional and practical hurdles. The commenter argues that the use of Ramsey-derived rates allows EPA to choose parameter values that do not fit the investment and savings levels observed in the real world. The commenter questions the use of the Ramsey formula since return to capital are observable and show higher rates than rates produced by Ramsey calculations, which the commenter suggests may mean the Ramsey-derived rates are not optimal. The commenter states that even if EPA’s calculation is mathematically optimal, it does not reflect real world economic scenarios. The commenter states “[u]nless this Ramsey optimality holds across all investments, it is not optimal to use this calculated rate for discounting.”

Commenter (2428-API) argues that EPA’s divergence from a constant 3 percent consumption rate of discounting is inconsistent with current OMB guidance and that EPA should refrain from alternate approaches until the 2023 proposed revisions of Circular A-4 are finalized.

Response A-5-8: The use of the Ramsey formula provides internal consistency within the modeling between the socio-economic scenarios and the discount rate. As noted in report, the Ramsey formula is widely used in the peer reviewed literature and is consistent with the National Academies’ (2017) recommendations on discounting, where they highlighted its internal consistency as an important feature. It is an important improvement over the use of a constant discount rate and incorporates links between the modules used for this estimate. However, as noted in the Final Report, the Ramsey formula, while widely used in the economics literature, is an approximation to highly complex real-world processes. EPA understands that non-market factors such as health and longevity may evolve over time in ways that could affect preferences for intertemporal tradeoffs in ways that are not currently included in the modeling. The EPA will continue to follow the literature on discounting and alternative specification that can incorporate additional characteristics, as feasible and appropriate.

EPA further notes that, while this RTC was being drafted, OMB finalized its updates to Circular A-4. The updated Circular A-4 (2023) guidelines clarify that agencies may develop economic

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<sup>140</sup> Cutler, D.M., Richardson, E., Keeler, T.E. and Staiger, D., 1997. Measuring the health of the US population. *Brookings papers on economic activity. Microeconomics*, 1997, pp.217-282.

<sup>141</sup> Nordhaus, W.D., 2002. The health of nations: the contribution of improved health to living standards.

<sup>142</sup> Romer, P.M., 1986. Increasing returns and long-run growth. *Journal of political economy*, 94(5), pp.1002-1037.

<sup>143</sup> Romer, P.M., 1990. Endogenous technological change. *Journal of political Economy*, 98(5, Part 2), pp.S71-S102.

models in which the evolution of the discount rates is endogenous, which is precisely the approach EPA has developed here.

Comment: Commenters (2398-Policy Integrity NYU, 2339- A. Fraas et al., 2428-API) question the Treasury security rates used to calibrate the near-term discount rates. Commenter (2398-Policy Integrity NYU) contends that an analysis of recent Treasury returns supports a lower near-term discount rate than is used in EPA’s Draft Report. Conversely, commenter (2339-A. Fraas et al.) argues that EPA’s calibration of discount rates to Treasury notes is likely to bias downward the proposed consumption discount rate. Commenter (2428-API) questions whether there is a structural break in Treasury rates, and commenter (2361-EPRI) argues that analyzing short-run investments over recent decades is impractical in the context of climate change.

Commenter (2398-Policy Integrity NYU) suggests that EPA’s Draft Update discount rate range is too high and offers evidence suggesting an improved range of 0.5% to 2.5% with a central rate of 1.5%. The commenter argues that the academic literature is in support of EPA’s claim of a structural break in Treasury yields occurring in the early 1990s. The commenter notes that EPA’s focus on the 30-year period after this structural break supports a discount rate ranging from 1.5 to 2 percent, with an average rate of 1.7 percent. The commenter further states that recent research (Bauer & Rudebusch, 2023)<sup>144</sup> suggests a continued downward trend in Treasury yields and a real interest rate of 1 percent or less in the 2010s. Given this research, and EPA’s claim of prioritizing the 30-year time period, the commenter argues that is unclear why EPA presents the 1.5 rate on equal footing as the 2.5 rate. The commenter states that even a conservative interpretation of Bauer & Rudebusch (2023)<sup>145</sup> supports a discount rate range of 0.5 to 2.5 percent with a central rate between 1.0 and 1.5 percent.

Commenter (2339-A. Fraas et al.) argues that given the long forecasting time horizon of EPA’s analysis, interest rate behavior in recent decades is not necessarily more relevant than interest rates in earlier periods. The commenter notes that “there is no discussion of the effect of the remarkable monetary policy pursued by the Federal Reserve over the last several decades, which have kept interest rates on Treasuries artificially low, or that fiscal policy is now becoming more expansionary.” The commenter further argues that only a small percentage of consumers own Treasury securities, leading to a segmentation of the capital market and a range of markets for consumption smoothing.<sup>146</sup> The commenter notes that EPA acknowledges this on page 59 of the Draft Report. The commenter further notes that several studies<sup>147, 148, 149</sup> document higher marginal rates of time preference. The commenter discusses the energy efficiency paradox and

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<sup>144</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>145</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>146</sup> Stern, N., Stiglitz, J. and Taylor, C., 2022. The economics of immense risk, urgent action and radical change: towards new approaches to the economics of climate change. *Journal of Economic Methodology*, 29(3), pp.181-216.

<sup>147</sup> Damigos, D., Kontogianni, A., Tourkolias, C. and Skourtos, M., 2021. Dissecting subjective discount rates and investment literacy for energy-efficient investments. *Energy Efficiency*, 14(3), pp.1-20

<sup>148</sup> Harrison, G.W., Lau, M.I. and William, M.B., 2002. Estimating individual discount rates in Denmark: A field experiment. *American Economic Review*, 92(5), pp.1606-1617.

<sup>149</sup> Warner, J.T. and Pleeter, S., 2001. The personal discount rate: Evidence from military downsizing programs. *American Economic Review*, 91(1), pp.33-53.

argues that the private market does not pursue energy efficiency options that EPA's benefit-costs analysis find optimal potentially due to higher discount rates of the population and cites Gillingham and Palmer (2014)<sup>150</sup> and Helfand and Dorsey-Palmateer (2015).<sup>151</sup>

Commenter (2428-API) urges EPA to provide more justification for the "claim that long-term structural breaks in the interest rate imply lower interest rates in the future" and cites a working paper<sup>152</sup> that disputes the notion of structural breaks. The commenter also asks that EPA explain how near-term interest rates from the last 30 years can fully inform the choice of an appropriate discount rate for the SC-GHG, given the projection horizon of 300 years.

Commenter (2361-EPRI) states that "[c]omparing to 10-year Treasury or other relatively short run observed investment rates over the last few decades, or even fifty years, is impractical given the century long GHG investments being modeled and multi-century SC-GHG modeling horizon." The commenter advocates for benchmarking to investments that are longer than 10 years which have a centuries-long time series. The commenter notes that 3% represents the long-run real interest rates for social security from 1870 to 2005 and argues that this is the appropriate benchmark given the long-time horizon and that it reflects the long-run trade-offs in consumption.

Response A-5-9: EPA recognizes that a range of empirical evidence suggestive of a downward secular trend in interest rates and therefore, does place a greater focus on the range of mean interest rate estimates from 1991-2020. However, the range of near-term discount rates used in the report are based on multiple lines of evidence, including historical real rates of returns, empirical studies of equilibrium real interest rates, future projections of real interest rates, empirical evidence of long-run discount rates implied by real estate markets, and surveys of economists and technical experts. Looking across this wide body of evidence, EPA finds broad support for a near-term discount rate in the range of 1.5% to 2.5% with a central focus on 2.0%.

As commenters note, one line of evidence considered by EPA includes the average real rate of return on 10-year Treasury Securities. EPA finds support in economics literature for using returns on 10-year Treasury Securities as a risk-free measure of intertemporal tradeoffs appropriate for calibrating discount rates (e.g., Newell and Pizer 2003<sup>153</sup>, Bauer and Rudebusch 2023<sup>154</sup>). In addition, EPA notes that the average real rate of return on 10-year Treasury securities has formed the basis for OMB's Circular A-4 (2003) guidance on consumption

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<sup>150</sup> Gillingham, K. and Palmer, K., 2014. Bridging the energy efficiency gap: Policy insights from economic theory and empirical evidence. *Review of Environmental Economics and Policy*, 8(1), pp.18-38.

<sup>151</sup> Helfand, G. and Dorsey-Palmateer, R., 2015. The Energy Efficiency Gap in EPA's Benefit-Cost Analysis of Vehicle Greenhouse Gas Regulations: A Case Study. *Journal of Benefit-Cost Analysis*, 6(2), pp.432-454.

<sup>152</sup> Rogoff, K. S., Rossi, B., & Schmelzing, P. (2022). *Long-run trends in long-maturity real rates 1311-2021* (No. w30475). National Bureau of Economic Research.

<sup>153</sup> Newell, R.G. and Pizer, W.A., 2003. Discounting the distant future: how much do uncertain rates increase valuations? *Journal of environmental economics and management*, 46(1), pp.52-71

<sup>154</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

discount rates.<sup>155</sup> One specific line of evidence considered by EPA includes the average rate of return over the past 30 years. While highly informative EPA did not select the near-term discount rate based solely on this one line of evidence. In addition, EPA considered the average real rate of return on 10-year Treasury Securities over a longer period going back to the early 1970s in addition to empirical literature that considered equilibrium real interest rates on government securities. Using a time series of 10-Year Treasury securities, Bauer and Rudebusch (2023) estimate a current equilibrium real interest rates of 1.3, 1.9, and 2.4 percent, the lower estimate from the author’s univariate unobserved-components (UC) model. In their online appendix, Bauer and Rudebusch (2023) also consider a longer 220-year time series of real return to government securities and find a similar range of equilibrium real interest rates (1.5, 2.3, and 3.0 percent). Furthermore, the interest rate on the 30-year Treasury bond, which is also informative of long-run social time preferences and is likely less influenced by short-run monetary policy interest rate fluctuations, is on average only 0.5 to 0.7 percentage points higher than the interest rate on 10-year bond. But across these lines of evidence there is a consistent finding of a downward secular trend in real interests over time. In addition, EPA considered long-term forecasts of future real interest rates conducted by the U.S. Congressional Budget Office and the Social Security Administration, with the latter going out to 2100. EPA also considered long-run discount rates implied by real estate markets. As discussed in the Final Report, Giglio et al. (2015)<sup>156</sup> find that the discount rate for 100-year real estate claims is 2.6%. The authors argue that since real estate is a risky asset, this value provides an upper bound for the long-run risk-free rate of interest (Giglio et al. 2015, Giglio et al. 2021<sup>157</sup>). Finally, EPA also considered recent surveys of economists and technical experts on the appropriate discount rate, which EPA found to be consistent with the empirical evidence.

Comment: Commenters (2428-API, 2361-EPRI, 2239-A. Fraas et al.) question the RFF-SP economic growth projections and the implications for EPA’s discounting module.

Commenter (2428-API) urges EPA to state and explain how it calculates the near-term real growth rate of consumption per capita ( $g_t$ ). The commenter notes that “to recover the Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed.” However, the commenter remarks that EPA notes that the average global per capita growth rates have been closer to 2% in recent decades. Additionally, in discussing the calibration of the Ramsey parameters, the commenter requests that EPA clarify how it estimates the near-term consumption growth rate “net of baseline climate change damages” beyond what is offered in Appendix 3 of EPA’s Draft Report.

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<sup>155</sup> OMB’s Circular A-4 (2023) guidance on consumption discount rates likewise was based on the average real rate of return on 10-year Treasury marketable securities (OMB 2023). OMB noted that such securities are widely held through, for example, pension fund investments, and reflect the market price at which individuals can make nearly risk-free loans. OMB Circular No. A-4: Explanation and Response to Public Input (2023), <https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4Explanation.pdf>.

<sup>156</sup> Giglio, S., Maggiori, M. and Stroebel, J., 2015. Very long-run discount rates. *The Quarterly Journal of Economics*, 130(1), pp.1-53.

<sup>157</sup> Giglio, S., Maggiori, M., Rao, K., Stroebel, J. and Weber, A., 2021. Climate change and long-run discount rates: Evidence from real estate. *The Review of Financial Studies*, 34(8), pp.3527-3571.

Commenter (2361-EPRI) recommends that EPA remove the feature netting out damages from economic growth. The commenter argues that “[i]f damages are changing the projected economic growth rates, then the resulting discount rate is no longer consistent with assumed growth and the required equilibrium condition that insures that deferred consumption is sufficient for projected growth no longer holds.” The commenter argues that EPA’s approach is inconsistent with the discussion on page 49 of the EPA Draft Report in which EPA explains why damages specifications that include the effect of climate damages on economic growth were not chosen. The commenter further argues that this approach is inconsistent with the use of consumption near-term target interest rates. The commenter argues for an assumed economic growth rate of 1.9% to 2% for a global calibration.

The commenter (2361-EPRI) questions the assumption that the savings rate is fixed (and thus GDP and consumption growth are identical) and presents historical data that illustrates that world and regional savings rates change over time and vary by region. The commenter notes that EPA’s fixed savings rate assumption should be revised, as it has significant implications for EPA’s discounting growth rates. The commenter notes significant variation in regional historical growth rates and argues that EPA should use regional discounting for consistency with projected regional growth rates. Commenter (2428-API) similarly argues that EPA should explain the rationale for using the same discount rate for all regions and notes that the economic growth rate varies across regions. The commenter states that “EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.”

Commenter (2239-A. Fraas et al.) remarks that the assumptions underlying the calibration EPA’s social discount rates are not well justified and that the growth process used in the Ramsey formula are unclear in the EPA Report. The commenter notes an important category of uncertainty – the possibility of major economic disruptions, such as economic depressions, wars, financial crises, and pandemics that are unrelated to climate change. The commenter cites previous research<sup>158,159,160</sup> on this topic as well as a paper<sup>161</sup> that suggests adding a risk premium to account for this category of uncertainty. As an alternative, the commenter argues that it is possible to model these events explicitly by incorporating a perturbation (a sharp decline) in the growth rate following by a higher-than-average growth rate which returns the economy back to the average rate of growth. The commenter states that the effect of this perturbation would carry through the discount rate and damage estimates and should reflect the past and expected future frequencies of catastrophic economic disruptions. The commenter states that one of the reasons why they believe EPA’s Draft Report understates the consumption discount rate is that “uncertainties about the growth rate and the possibility of catastrophic damages suggest

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<sup>158</sup> Martin, I.W.R. and Pindyck, R.S., 2015. Averting Catastrophes: The Strange Economics of Scylla and Charybdis. *American Economic Review*. 105(10). 2947-85.

<sup>159</sup> Martin, I.W.R. and Pindyck, R.S., 2020. Welfare costs of Catastrophes: Lost Consumption and Lost Lives, *The Economic Journal*, 131(634), 946-969.

<sup>160</sup> Pindyck, R.S. & Wang, N., 2013b. The Economic and Policy Consequences of Catastrophes, *American Economic Journal – Economic Policy*. 5(4), 306-339.

<sup>161</sup> Freeman, M., Groom, B., & Spackman, M. 2018. Social Discount Rates for Cost–Benefit Analysis: A Report for HM Treasury.

additional risk premia that are not reflected in the statistical process that generates the growth forecasts.”

Response A-5-10: EPA calibrates the Ramsey parameters following the approach detailed by Newell, Pizer, and Prest (2022).<sup>162</sup> In this approach, the near-term certainty equivalent discount rate, that is the average over the first 10 years, is calibrated to be consistent with the near-term target discount rate. Because the calculation of the certainty equivalent discount rate is a non-linear operation, this is not the same as using the average near-term growth rate to calibrate the Ramsey parameters. Therefore, one cannot back out the exact average near-term growth rate in the RFF-SPs using the near-term target discount rate and the calibrated Ramsey parameters as suggested by one commenter.

The near-term per-capita economic growth rate used in the calibration procedure is from the RFF-SPs as described in detail in the draft and final report. There is heterogeneity in the growth rates over time as shown in Figure 2.1.2. In the Final Report, EPA has clarified that the average economic growth per capita in the set of RFF-SPs used in the modeling ranges is around 1.4% in the initial years.

As stated in the Report, when using the Ramsey formula to estimate the SC-GHG, the per capita consumption growth rate,  $g_t$  is calculated net of baseline climate change damages. More specifically, in a given run, the economic growth rate per capita used in the Ramsey formula for the purposes of discounting is calculated by subtracting baseline climate damages per capita, as estimated by the damage modules described in Section 2.3, from the economic output per capita in the RFF-SPs and taking the growth rate. Regarding the netting of climate damages from economic growth when applying the Ramsey formula, Kelleher and Wagner (2019)<sup>163</sup> explain that the correct approach is to subtract the baseline climate damages from the economic growth rate, as these damages drive a wedge between output and consumption growth for which one should account.

EPA recognizes that savings rates change over time and vary by region but has used a constant savings rate as an approximation in applying the Ramsey formula, consistent with the literature. EPA acknowledges the commenters recommendation with regard to regional implementation of the Ramsey formula for discounting. The National Academies (2017) noted that damages could be aggregated across regions and discounted globally or discounted regionally and then aggregated, but using region-specific discount rates would requires Ramsey parameters calibrated for each region. EPA is not aware of peer-reviewed economic studies that have developed an approach to calibrating the Ramsey parameters at a country or region level using empirical evidence consistent with the National Academies’ (2017) recommendations. The Agency will continue to follow the scientific literature on probabilistic socioeconomic scenarios and potential regional calibration of Ramsey parameters.

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<sup>162</sup> Newell, R.G., Pizer, W.A. and Prest, B.C., 2022. A discounting rule for the social cost of carbon. *Journal of the Association of Environmental and Resource Economists*, 9(5), pp.1017-1046.

<sup>163</sup> Paul Kelleher, J. and Wagner, G., 2019. Ramsey discounting calls for subtracting climate damages from economic growth rates. *Applied Economics Letters*, 26(1), pp.79-82.

EPA understands that the probabilistic RFF-SPs may not incorporate all sources of economic uncertainty going forward; however, they will be representative of historical sources economic variation. The economic projections in the report are based on long-run growth dynamics from a model fit to historic data from 1900 – 2017 (Müller Stock, and Watson, 2022).<sup>164</sup> The period included major economic disruptions such as economic depressions, wars, financial crises, and pandemics. The economic projections represent estimates of long-run growth and not high frequency events such as business cycles or other short-lived impacts. The model allows for persistent excursions for the common global growth factor with reversion to the mean over the very long-run. These excursions are carried through the discount rate and damage module. The socioeconomic projections include many draws with negative growth rates in some years, which implicitly includes scenarios of major economic disruptions (see Figure 2.1.2 in the report).

Comment: Commenter (2428-API) questions whether EPA’s discount rates and parameters conform to surveys of experts cited in the Draft Report. Commenter (2183-M. Freeman et al.) suggests an alternative approach for calibrating the Ramsey parameters. Commenter (2361-EPRI) provides suggestions for Ramsey parameter calibration and additional module documentation.

Commenter (2428-API) notes that the calibrated Ramsey parameter,  $\rho$ , is lower than those found in Drupp et al. (2018)<sup>165</sup>. The commenter also references a passage from the EPA Draft Report which notes that small values of  $\rho$  could be associated with unreasonable optimal savings rates particularly with  $\eta$  around one. The commenter argues that such results call into question the choice of near-term discount rates and suggests that EPA should select the Ramey parameters and allow the near-term discount rates to be determined by the Ramsey formula.

Commenter (2183-M. Freeman et al.) suggests that the calibration of  $\rho$  and  $\eta$  are not reflective of the actual market rates for at least a decade prior to when the report was written. The commenter suggests a potential alternative: “fixing the short-end of the term structure to the market rate at the time the report was written, the long rate to the Bauer and Rudebusch (2023)<sup>166</sup> [estimates], and then applying a term structure for intermediate dates.”

Commenter (2361-EPRI) approves of EPA adopting a dynamic discounting approach following the NASEM recommendations but questions the calibration of the near-term discount rates. The commenter argues that the  $\rho$  parameter should be positive and that the  $\eta$  parameter should be greater than one. Citing Stern (2006)<sup>167</sup> and Nordhaus (2006)<sup>168</sup>, the commenter argues that  $\rho$  values of 0.1% have been controversial as this suggests that consumers are indifferent between current and future consumption and states that this critique would certainly apply to EPA’s

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<sup>164</sup> Müller, U.K., Stock, J.H. and Watson, M.W., 2022. An Econometric Model of International Growth Dynamics for Long-Horizon Forecasting. *Review of Economics and Statistics*, 104(5), pp.857-876.

<sup>165</sup> Drupp, M.A., Freeman, M.C., Groom, B. and Nesje, F., 2018. Discounting disentangled. *American Economic Journal: Economic Policy*, 10(4), pp.109-34.

<sup>166</sup> Bauer, M.D. and Rudebusch, G.D., 2023. The Rising Cost of Climate Change: Evidence from the Bond Market. *The Review of Economics and Statistics*, 105(5), pp.1255-1270.

<sup>167</sup> Stern, N, 2006. Stern Review: The Economics of Climate Change

<sup>168</sup> Nordhaus, WD, 2006. “The Stern Review on the Economics of Climate Change,” November, p.6.

choice of 0.01% for  $\rho$ . The commenter further argues that an  $\eta$  less than 1.5 implies a very large savings rate of 67% and cites Arrow (1999).<sup>169</sup>

Commenter (2361-EPRI) expresses that the discounting module's documentation requires explicitly stated calibration and calculation details of every aspect of the discounting approach instead of relying on the literature cited for essential details. Specifically, the commenter notes that "details are needed on the specific lines of evidence regarding observed rates, use of the probabilistic socioeconomic scenarios in the calibration, and assumptions and constraints during calibration."

Response A-5-11: EPA calibrates the parameters of the Ramsey formula following the approach of Newell et al. (2022), as applied in Rennert et al. (2022a, 2022b). Under this approach, the parameters are calibrated such that (1) the decline in the certainty-equivalent discount rate path matches the latest empirical evidence on interest rate uncertainty estimated by Bauer and Rudebusch (2023) and (2) the average of the certainty-equivalent discount rate over the first decade matches a near-term consumption rate of interest based on multiple lines of evidence as to the near-term consumptions interest rate. This approach is consistent with the National Academies (2017) recommendation that the parameters in the Ramsey formula be chosen in a manner "consistent with theory and evidence and that produce certainty-equivalent discount rates consistent, over the next several decades, with consumption rates of interest." This approach provides an empirical basis for calibrating the Ramsey parameters and results in values that are within the ranges used in the peer-reviewed literature (see Table 6-1 in NASEM 2017<sup>170</sup>). The calibrated values are also consistent with those recommended by recent surveys. The values for  $\eta$  and  $\rho$  in Table 2.4.2 of the report are consistent with the range of central tendency estimates reported in Drupp et al. (2018).<sup>171</sup> EPA finds this data driven approach to calibrating the Ramsey parameters more appropriate than selecting values of the Ramsey parameters that potentially inconsistent with observed interest rates.

As highlighted by commenter (2183-M. Freeman et al.), the average real rate of return on the 10-year Treasury bond is sensitive to the time period analyzed and the measures of inflation expectations used. This is, in part, why EPA considered multiple lines of evidence when calibrating the near-term discount rate. It is also why EPA finds that fixing the short-end of the term structure to a single measure of a market rate at the time the estimates are developed will introduce additional uncertainty and is inappropriate.

EPA notes that the report, appendices, citations contained therein, and the online repository of replication source code provide specific details on the discounting approach including, calibration, lines of evidence regarding observed rates, and use of the probabilistic socioeconomic scenarios in the calibration.

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<sup>169</sup> Arrow, KJ, 1999. Discounting, Morality, and Gaming. In Portney, PR and JP Weyant (eds), Discounting and Intergenerational Equity. Resources for the Future, Washington, DC.

<sup>170</sup> National Academies of Sciences, Engineering, and Medicine. 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. <https://doi.org/10.17226/24651>.

<sup>171</sup> Drupp, M.A., Freeman, M.C., Groom, B. and Nesje, F., 2018. Discounting disentangled. *American Economic Journal: Economic Policy*, 10(4), pp.109-34.



Comment: Commenters (2413-CEI/HF, 2339-INGAA, 2361-EPRI, 2445- J. Davis, 2428-API, 2344-IER, 2239-A. Fraas) raise concerns regarding the near-term discount rates used in EPA’s Draft Report and argue that the discount rate range should be higher. Commenters (2239- A. Fraas et al., 2361-EPRI) question whether regulatory compliance will also displace capital investment. Commenters (2428-API, 2344-IER, 2339-INGAA) state that EPA’s approach is inconsistent with OMB Circular A-4 (2003).

Commenter (2361-EPRI) states that near-term target rates should be 3-5%. The commenter argues that the 3% rate is consistent with very long-run consumption tradeoffs and presents an analysis of government real interest rates for social security from Girola (2005)<sup>172</sup>. The commenter notes that the 5% value is consistent with long-run private investment trade-offs and cites several research papers<sup>173,174,175</sup>. The commenter notes that consumption trade-off “do not appear to be what is modeled in the damage calculations”, instead, “the damage categories appear to be computing changes in private investment, aggregate consumption, or trade-offs with utility”, which the commenter argues, appear to be consistent with trade-offs at the macroeconomic level.

Commenter (2239-A. Fraas) argues that the discount rate range used in the draft guideline understates the consumption discount rate. The commenter notes the small response rate in the surveys of economic experts cited by EPA and also notes that the means of discount rate responses for certain groups of experts are above EPA’s upper end near-term target rate. The commenter further argues that the low consumer discount rates are not appropriate for evaluating regulations that displace corporate investment. The commenter states that it seems likely that EPA climate regulations will impact both consumption and investment. The commenter argues that a key rationale for using the opportunity cost of capital in regulatory analysis is that it ensures that there are no other uses of investment capital that could result in a Pareto improvement. The commenter notes that this logic applies both intra- and inter-generationally and cites several research papers<sup>176,177,178,179,180,181</sup>.

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<sup>172</sup> Girola, JA, 2005. The long-term real interest rate for social security, Research Paper No. 2005-02, US Treasury, March. <https://home.treasury.gov/system/files/226/long-term-rates-socialsecurity.pdf>.

<sup>173</sup> Nordhaus, WD, 2010. Economic aspects of global warming in a post-Copenhagen environment. *Proceedings of the National Academy of Sciences*, 107(26), 11721–11726

<sup>174</sup> Nordhaus, WD, 2017. Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences* 114(7): 1518–1523.

<sup>175</sup> Manne, A, R Richels, 1992. *Buying Greenhouse Insurance: The Economic Costs of CO2 Emission Limits*. The MIT Press, 1st edition.

<sup>176</sup> Viscusi, W. K., Huber, J., & Bell, J. 2019. Responsible Precautions for Uncertain Environmental Risks. *Journal of Benefit-Cost Analysis*, 10(2): 296-315.

<sup>177</sup> Kaplow, L., 2006. Discounting dollars, discounting lives: Intergenerational distributive justice and efficiency. NBER Working Paper, 12239.

<sup>178</sup> Lind, R.C., 1995. Intergenerational equity, discounting, and the role of cost-benefit analysis in evaluating global climate policy. *Energy Policy*, 23(4-5), pp.379-389.

<sup>179</sup> Liu, L., Rettenmaier, A.J. and Saving, T.R., 2021. Discounting Environmental Benefits for Future Generations. *Public Finance Review*, 49(1), pp.41-70.

<sup>180</sup> Weisbach, D.A. and Sunstein, C.R., 2008. Climate change and discounting the future: a guide for the perplexed. *Yale Law & Policy Review*, 27, p.433.

<sup>181</sup> Weyant, J.P., 2008. A critique of the Stern Review's mitigation cost analyses and integrated assessment. *Review of Environmental Economics and Policy*, 2(1), pp.77-93.

The commenter (2239-A. Fraas) notes that Li and Pizer (2021)<sup>182</sup> estimate the shadow price of capital and find that it is only in the long run that the social discount rate declines to the consumption rate. The commenter emphasizes that “the target discount rates used to start off the temporal discount rate path should not be based on a consumption rate, as is suggested in the EPA-ERD, when regulatory compliance displaces capital investment.” The commenter states that both the shadow price of capital approach and EPA’s approach require an estimate of the opportunity cost of capital, which the commenter argues, is remarkably stable at 7 percent.

Commenter (2445-J.K. Davis) contends that EPA should use a 7% discount rate, in line with traditionally accepted norms, to evaluate the future impacts of proposed regulations. The commenter suggests that EPA employed a 3% rate and has amplified the perceived cost of greenhouse gases without adequate scientific justification.

Commenter (2227- W. Energy Alliance) notes that EPA uses lower discount rates than have been historically used in the SC-GHG report. The commenter further notes that the choice of discount rate can be manipulated to arrive at the SC-GHG that is desired. The commenter recommends that EPA conduct a coherent analysis using a range of discount rates to address the continued controversy surrounding discount rates.

Commenter (2344-IER) argues that EPA has chosen to “willfully ignore and mischaracterize the requirements of Circular A-4” by omitting estimates using a 7 percent discount rate. The commenter emphasizes that OMB Circular A-4 (2003) allows for sensitivity analyses with lower discount rates for contexts with intergenerational impacts “in addition to calculating net benefits using discount rates of 3 and 7 percent.” The commenter states that “To have a robust set of alternative scenarios, EPA has to include a scenario with a 7 percent discount rate.”

The commenter (2344-IER) further argues that low intergenerational discount rates are inappropriate. The commenter states that discounting and discount rates “are not tools for weighing the relative value of people’s welfare in different time periods, instead, they are tools for ranking different investments” and argues that discounting at the 2 percent rate is therefore not more equitable to future generations than discounting at the 7 percent rate. The commenter argues that it is likely future generations will be much wealthier and better equipped to overcome climate change than people today. Therefore, the commenter suggests EPA inequitably reduces the welfare of disadvantaged people today in order to benefit the future wealthy.

Commenter (2339-INGAA) states that EPA acknowledges the arguments for lower discount rates but ignores the countervailing arguments for higher discount rates, which the commenter argues is one-sided. The commenter argues that “[u]sing a 7% discount rate, consistent with Circular A-4, is entirely defensible on grounds that society should evaluate costly investments in GHG emissions reductions by comparing them to the foregone returns on a same-sized investment elsewhere,” and cites Kreutzer (2016)<sup>183</sup>. The commenter further argues that “intergenerational equity considerations provide a strong rationale for using higher discount

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<sup>182</sup> Li, Q. and Pizer, W.A., 2021. Use of the consumption discount rate for public policy over the distant future. *Journal of Environmental Economics and Management*, 107, p.102428.

<sup>183</sup> David Kreutzer, Discounting Climate Costs, Heritage Found. (June 16, 2016), <https://tinyurl.com/ys9e9ay6>.

rates, on grounds that money/utility should not be transferred to the comparatively wealthy (i.e., future generations) at the expense of the comparatively poor (i.e., the current generation).”

Commenter (2361-EPRI) questions the discount rate on the basis of potential inconsistencies between benefits and costs in analyses using the SC-GHG estimates given differences in how climate benefits are discounted compared to regulatory compliance costs.

Response A-5-12: The discount rates used in the Report on the SC-GHG are consistent with the guidelines in OMB Circular A-4 (2003).<sup>184</sup> The Circular states that “the analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption and to discount them at the rate consumers and savers would normally use in discounting future consumption benefits” (OMB 2003).<sup>185</sup> Because the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, the application of this 2003 OMB guidance is to use the consumption discount rate to calculate the SC-GHG.<sup>186</sup> Circular A-4 also notes that “[s]pecial ethical considerations arise when comparing benefits and costs across generations” and advises consideration of lower but positive discount rates (OMB 2003).<sup>187</sup>

In 2010 and in every update to the social cost of greenhouse gases, the IWG maintained that the consumption rate of interest is the correct discounting concept to use when the future damages from climate change that are estimated in consumption-equivalent units. The National Academies (2017)<sup>188</sup> similarly stated that when discounting damages measured as consumption equivalents, as is the case in EPA’s damage estimates, the consumption rate of interest is the appropriate concept. Furthermore, the National Academies (2017) recommended that the IWG “choose parameters for the Ramsey formula that are consistent with theory and evidence and that produce certainty-equivalent discount rates consistent, over the next several decades, with consumption rates of interest.”

As detailed in the report, and above, EPA examined multiple lines of evidence when selecting the near-term target consumption interest rates for calibrating the Ramsey formula. EPA considered historical real rates of returns, empirical studies of equilibrium real interest rates, future projections of real interest rates, and surveys of economists and technical experts. EPA recognizes that there are strengths and limitations associated with each of these lines of evidence, which emphasizes the importance of considering multiple lines. Looking across this wide body

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<sup>184</sup> Office of Management and Budget (OMB). 2003. *Circular A-4, Regulatory Analysis*. OMB. [https://obamawhitehouse.archives.gov/omb/circulars\\_a004\\_a-4/](https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/)

<sup>185</sup> Similarly, OMB’s Circular A-4 (2023) points out that “The analytically preferred method of handling temporal differences between benefits and costs is to adjust all the benefits and costs to reflect their value in equivalent units of consumption before discounting them” (OMB 2023).

<sup>186</sup> The same guidance is provided for in Circular A-4 (2023) (OMB 2023).

<sup>187</sup> Circular A-4 (2023) (OMB 2023) likewise recognized special ethical considerations in the intergenerational discounting context. It also recognized long-term uncertainty in the discount rate when recommending consideration of discount rates below the near-term social rate of time preference when a rule has important intergenerational benefits or costs.

<sup>188</sup> National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. National Academies Press.

of evidence, EPA finds broad support for a near-term consumption interest rates in the range of 1.5% to 2.5% with a central focus on 2.0%.

Multiple commenters point to the potential for the cost of regulatory requirements to displace of capital investment as cause for using a higher discount rate when estimating the SC-GHG. EPA is aware that because of market distortions, such as taxes on capital income, the overall social burden is greater in the case where investment is displaced relative to consumption. As noted in OMB Circular A-4 (2003 and 2023), the theoretically correct approach to addressing this issue would be to convert the impacts of displaced capital investment into consumption equivalents using the shadow price of capital (SPC) and then discount them at the consumption interest rate. As detailed in Appendix A.2 of the report, using the social opportunity cost of capital to discount the marginal damages when estimating the SC-GHG would not be an appropriate process for incorporating additional costs associated with displace capital investment into regulatory analysis. Instead, any potential effects on capital investment should be address directly, using the SPC approach as recommended by Circular A-4 (2003).<sup>189</sup> Li and Pizer (2021)<sup>190</sup> show that when impacts are borne over a long-time horizon, as is the case with climate change, using an ad hoc upward adjustment to the discount rate to account for capital displacement can result in significant analytical errors relative to the SPC approach. Therefore, EPA uses a consumption interest rate to discount when estimating the SC-GHG, consistent with the recommendations of the National Academies (2017).

Comment: The commenters (2227- W. Energy Alliance, 2339-INGAA) request that EPA clarify to what extent the choice of lower near-term discount rates is responsible for the difference between EPA's External Review Draft SC-CO<sub>2</sub> and the previous 2021 IWG SC-CO<sub>2</sub>.

Commenter (2227-W. Energy Alliance) criticizes the comparison of new SC-CO<sub>2</sub> estimates to the existing estimates without acknowledging the difference in discount rates.

Commenter (2339-INGAA) argues that EPA should disclose how much of the difference in SC-GHG values between the Draft Report and the IWG interim estimates are attributable to a lower discount rate. The commenter argues that the EPA Report follows closely the methodology of Rennert et al. (2022b)<sup>191</sup>, and in this paper, the authors show a substantial decline in the SCC estimates due to a shift in the discount rate from 3 to 2 percent.

Response A-5-13: The increases in the SC-GHG estimates are due to the combined effect of the methodological updates described in Section 2 of the report, some of which are integrated in a way that makes a complete decomposition of the incremental contribution of each change difficult for all three damage functions used in the damage module. For example, a comparison of SC-GHG estimates based on a constant 3% discount rate with results based on a 2% near-term Ramsey discount rate reflects the combined effect of using of a lower near-term rate and the shift

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<sup>189</sup> Circular A-4 (2023) provides additional discussion on implementing this approach.

<sup>190</sup> Li, Q. and Pizer, W.A., 2021. Use of the consumption discount rate for public policy over the distant future. *Journal of Environmental Economics and Management*, 107, p.102428.

<sup>191</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692

from a constant to a dynamic discounting approach that accounts for the possible correlations between climate change damages and economic growth through the use of probabilistic RFF-SPs growth projections. A re-estimation of the IWG recommended interim estimates using lower constant discount rates finds that the SC-CO<sub>2</sub> increases from \$51/mtCO<sub>2</sub> to \$121/mtCO<sub>2</sub> for 2020 emissions when shifting from a constant 3% to a constant 2% discount rate (NYSDEC 2022). This illustrates that the combined effect of shifting to a dynamic discount rate approach together with the socioeconomic, climate, and damage module updates accounts for the additional 60% increase in the SC-CO<sub>2</sub> to \$190/mtCO<sub>2</sub> for 2020 emissions presented in Table 4.1.1 of the report. This does not imply that each update influences the SC-GHG in the same direction. For example, ignoring the correlation between climate change damages and economic growth – as is the case with a constant discount rate approach – can lead to overestimating the SC-GHG if there is a positive correlation between economic growth and marginal damages. See, for example, Newell et al. (2022) and Rennert et al. (2022b) for an illustration of this potential. Table 1 in Rennert et al. (2022b) also provides an analysis that illustrates the incremental impact of some of the other updates in the GIVE model, relative to a recent version of the DICE model. For example, the authors find that the use of the GIVE damage functions increases the SC-CO<sub>2</sub> by 36% (from \$59/tCO<sub>2</sub> to \$80/tCO<sub>2</sub> for 2020 emissions), relative to a model run that uses the updated FaIR-based climate modelling, the RFF-SP socioeconomic module, and the Ramsey discounting approach reflecting a 3% near-term discount rate but retains the DICE-2016R damage function. In the case of methane, the IWG interim SC-CH<sub>4</sub> estimate under a 2% constant discount rate (\$2,700/mtCH<sub>4</sub> for 2020 emissions (NYSDEC 2022)<sup>192</sup>) exceeds the fully updated SC-CH<sub>4</sub> estimate under a 2% near-term Ramsey discount rate presented in Table 4.1.1 of the report.<sup>193</sup>

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<sup>192</sup> New York State Department of Environmental Conservation (NYSDEC), 2022. Establishing a Value of Carbon: Guidelines for Use by State Agencies. <https://www.dec.ny.gov/regulations/56552.html>.

<sup>193</sup> For a full listing of the IWG SC-GHG recommended values re-estimated using lower constant discount rates, see NYSDEC (2022), available at: <https://www.dec.ny.gov/regulations/56552.html>.

## A.6 Global Focus in SC-GHG Estimates

Comment: Commenters (2397-Climate Alliance, 2398-Policy Integrity NYU, 2246-NRDC, 2208-CCES et al., 2281-CCES et al., 2410-CA AG et al., 3174-Climate Science et al., 2313-M. Plevin-Faust,) express support for the consideration of global damages in EPA’s Draft Report on the SC-GHG. The commenters make numerous arguments in favor of considering global damages. Commenters (2398-Policy Integrity NYU, 2208-CCES et al.) contend that EPA’s consideration of global climate damages is both economically sound and consistent with previous approaches, including those developed under the George W. Bush administration. The same commenters highlight OMB Circular A-4 (2003)’s recommendation for agencies to report effects beyond the borders of the United States and note that agencies regularly consider costs and benefits to foreign entities in their decision-making. The commenters (2398-Policy Integrity NYU, 2208, 2281-CCES et al.) provide examples of precedents that support extraterritorial effects, such as NEPA analyses and EPA’s past consideration in the context of stratospheric ozone regulation, and highlights court decisions that have upheld EPA’s authority to consider global impacts. Furthermore, the same commenters argue that across a wide range of contexts – including outside the climate context – agencies have justified rules on the importance of international reciprocity and cooperation.

Commenter (2398-Policy Integrity NYU) summarizes that EPA is acting rationally in accounting for climate impacts on a global basis, and that this method is consistent with historical examples of agency regulatory authority. The commenter encourages EPA to highlight this point as support for its global approach. Commenter (2398-Policy Integrity NYU) provides a thorough analysis of the historical and legal frameworks under which U.S. agencies, including EPA, have considered the transboundary environmental effects of domestic actions. The commenter highlights the National Environmental Policy Act (NEPA) as a fundamental piece of legislation that instructs agencies to recognize global environmental challenges and foster international cooperation, as stipulated by 42 USC section 4332.<sup>194</sup> Consistent with NEPA’s directives, U.S. agencies have, for over four decades, assessed the impacts of their actions that extend beyond national borders. Commenter (2398-Policy Integrity NYU) notes that NEPA instructs and in some cases requires agencies to consider transboundary impacts of environmental problems. The commenter further clarifies that courts have often upheld EPA’s authority to consider international cooperation when setting domestic pollution standards, including the U.S. Court of Appeals for the D.C. Circuit in *National Coalition Against the Misuse of Pesticides v. Thomas*.<sup>195</sup> The commenter provides several other examples of courts upholding EPA’s power to do so, as well as instances of other agencies regulating based on international cooperation in climate contexts and beyond (e.g., spillover effects in the case of the Department of Energy’s consideration of liquefied natural gas exports to nations with which the United States does not have a free trade agreement).

Further underlining the federal commitment to acknowledging the international ramifications of domestic actions, Commenter (2398-Policy Integrity NYU) cites the 1979 Executive Order 12114, which establishes procedures for agencies to consider environmental effects outside the

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<sup>194</sup> 42 U.S.C. § 4332(2)(F)

<sup>195</sup> 815 F.2d 1579 (D.C. Cir. 1987).

U.S. territories.<sup>196</sup> The executive order emphasizes the importance of safeguarding the environment of the global commons, foreign nations, and globally significant ecological resources.<sup>197</sup> Building upon this, the Council on Environmental Quality in 1997 reinforced the necessity for agencies to analyze the foreseeable transboundary effects of proposed domestic actions in NEPA analyses.<sup>198</sup>

To further demonstrate the legal breadth and historical consideration of transboundary effects, the Commenter (2398-Policy Integrity NYU) references several court decisions. The commenter states that these judgements, such as the D.C. Circuit’s verdict in *Environmental Defense Fund v. Massey*,<sup>199,200</sup> and other court precedents like *Manitoba v. Salazar*<sup>201</sup> and *Backcountry Against Dumps v. U.S. Department of Energy*,<sup>202</sup> have emphasized the responsibility of agencies under NEPA to consider the foreseeable transboundary environmental effects of their actions. While there may be some inconsistencies in the case law about NEPA’s extraterritorial application,<sup>203,204</sup> the commenter finds the prevailing judicial sentiment to be aligned with the broader goal of NEPA – ensuring that federal agencies consider both domestic and global environmental implications of their actions, especially when these actions impact the global commons or the American environment.<sup>205</sup>

Commenter (2208, 2281-CCES et al.) expresses that EPA has appropriately focused on a global estimate of climate benefits, rejecting the temporary practice of the Trump administration of disregarding all climate effects that occur outside the physical borders of the United States. The commenter states that EPA should strengthen its justification by 1) emphasizing the concern for impacts of U.S. pollution on foreign welfare in the Clean Air Act and other sources of law, 2) further highlighting the significance of U.S. strategic interests and reciprocity, 3) further emphasizing the importance of extraterritorial impacts and spillovers, and 4) highlighting the inconsistency that would occur if the agency considered only domestic benefits while focusing on global costs.

**CAA:** The commenter (2281-CCES et al) notes that section 111 of the CAA, under which EPA issues the proposed rule, charges EPA with regulating “air pollution which may reasonably be anticipated to endanger public health or welfare,”<sup>206</sup> where “welfare” is defined to include “effects on . . . weather . . . and climate.”<sup>207</sup> When interpreting similar language in section 202 of the CAA, the Supreme Court found “there is nothing counterintuitive to the notion that EPA can curtail the emission of substances that are

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<sup>196</sup> Exec. Order No. 12,114 § 3, 44 Fed. Reg. 1957 (Jan. 4, 1979)

<sup>197</sup> Environmental Effects Abroad of Major Federal Actions, Exec. Order No. 12214, §§ 2-3, 3 C.F.R. 210 (1979).

<sup>198</sup> Council on Environmental Quality, Memorandum for Heads of Federal Departments and Agencies, Transboundary Effects of Proposed Actions, No. 97-16 (June 20, 1997).

<sup>199</sup> *Env’t Def. Fund, Inc. v. Massey*, 986 F.2d 528, 533-36 (D.C. Cir. 1993)

<sup>200</sup> *Id.* at 536

<sup>201</sup> *Gov’t of Man. v. Salazar*, 691 F. Supp. 2d 37, 51 (D.D.C. 2010)

<sup>202</sup> *Backcountry Against Dumps v. U. S. Dep’t of Energy*, No. 3:12-cv-03062-L-JLB, 2017 WL 3712487, at \*3 (S.D. Cal. Aug. 29, 2017)

<sup>203</sup> *Greenpeace USA v. Stone*, 748 F. Supp. 749, 759 (D. Haw. 1990)

<sup>204</sup> *Mayaguezanos por la Salud y el Ambiente v. United States*, 198 F.3d 297, 301 n.8 (1st Cir. 1999)

<sup>205</sup> *Massey*, 986 F.2d at 533–34, *Hirt*, 127 F. Supp. 2d at 845

<sup>206</sup> 42 U.S.C. §7411(b)(1)(A).

<sup>207</sup> 42 U.S.C. §7602(h); *Massachusetts v. EPA*, 127 S. Ct. 1438, 1447 (2007).

putting the global climate out of kilter.”<sup>208</sup> And when industry challenged another EPA climate program under Title I of the CAA by arguing that the statute “was concerned about local, not global effects,” the U.S. Court of Appeals for the D.C. Circuit had “little trouble disposing of Industry Petitioners’ argument that the [CAA’s prevention of significant deterioration (PSD)] program is specifically focused solely on localized air pollution,” finding instead that the statute was “meant to address a much broader range of harms,” including “precisely the types of harms caused by greenhouse gases.”<sup>209</sup> The commenter also notes a recent law-review article that exhaustively reviewed the legislative history of the CAA’s definition of “welfare” and concluded that “when Congress included the ‘effects on . . . climate’ language in the statute, it understood that adverse climate effects could occur on a global scale.”<sup>210</sup> For instance, the commenter reports that Senator Caleb Boggs, a Republican from Delaware and ranking minority member of the Public Works Subcommittee on Air and Water Pollution, which was considering the CAA in 1970, entered a report into the record stating that air pollution “alters climate and may produce global changes in temperature.”<sup>211</sup> Senator Jennings Randolph of West Virginia likewise submitted a statement into the record explaining that U.S. air pollution could “produce unacceptable worldwide climate changes.”<sup>212</sup> According to the commenter, Congress’s clear concern for the effects of domestic pollution on the global climate—many more examples of which are discussed in this law-review article—demonstrates that a global perspective is appropriate, if not required, when EPA regulates under the CAA.

**National Environmental Policy Act (NEPA):** The commenter (2281-CCES et al) provides that NEPA broadly declares a national environmental policy and requires of all agencies that “to the fullest extent possible[,] the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter,”<sup>213</sup> including the need to “recognize the worldwide and long-range character of environmental problems” and to “lend appropriate support” to help “maximize international cooperation.”<sup>214</sup> The commenter states that, especially because

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<sup>208</sup> *Massachusetts*, 127 S. Ct. at 1461 (emphasis added). This case concerned section 202 of the CAA, which similarly permits EPA to regulate “any air pollutant . . . which may reasonably be anticipated to endanger public health or welfare.” Id. at 1454 (quoting 42 U.S.C. §7521(a)(1)).

<sup>209</sup> *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 137-38 (D.C. Cir. 2012), aff’d in part, rev’d in part sub nom. *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

<sup>210</sup> Richard L. Revesz, Bostock and the End of the Climate Change Double Standard, 46 COLUM. J. ENV’T L. 1, 9 (2020).

<sup>211</sup> Id. at 32–33.

<sup>212</sup> Id. at 33.

<sup>213</sup> 42 U.S.C. § 4332(1)

<sup>214</sup> Id. § 4332(2)(F); see also *EDF v. Massey*, 986 F.2d 528, 536 (D.C. Cir. 1993) (“Section 102(2)(F) further supports the conclusion that Congress, when enacting NEPA, was concerned with worldwide as well as domestic problems facing the environment. . . . Compliance with one of the subsections can hardly be construed to relieve the agency from its duty to fulfill the obligations articulated in other subsections.”); *NRDC v. NRC*, 647 F.2d 1345, 1387 (D.C. Cir. 1981) (J. Robinson, concurring; J. Wilkey wrote for the Court, but there was no majority opinion) (concluding that even if a conflict with another statute prevents the agency from conducting an environmental impact statement, that “does not imply that NRC may ignore its other NEPA obligations,” including the “provision for multinational cooperation” and the “policy of the United States with respect to the ecological well-being of this planet”; rather, the agency “should remain cognizant of this responsibility”); *Greene County Planning Bd. v. Federal*



adopting a global perspective on climate damages will advance U.S. foreign policy goals, NEPA requires EPA to interpret all of its laws, including the CAA, in ways that recognize the worldwide character of environmental problems. As EPA recognizes in the Draft Update,<sup>215</sup> using global social cost of GHG estimates helps fulfill that requirement. Likewise, in a recent guidance document, the Council on Environmental Quality highlighted this very statutory language to conclude that “it is most appropriate for agencies to focus on [social cost of GHGs] estimates that capture global climate damages.”<sup>216</sup>

Additionally, the commenter notes that other key legal commitments compel this same conclusion. For instance, the United Nations Framework Convention on Climate Change—to which the United States is a party<sup>217</sup>—declares that national “policies and measures to deal with climate change should be cost-effective so as to ensure global benefits at the lowest possible cost.”<sup>218</sup> The Convention further commits parties to evaluating global climate effects in their policy decisions, by “employ[ing] appropriate methods, for example impact assessments . . . with a view to minimizing adverse effects on the economy, on public health and on the quality of the environment, of projects or measures undertaken by them to mitigate or adapt to climate change.”<sup>219</sup> According to the commenter, the unmistakable implication of the Convention is that parties—including the U.S.—must account for global economic, public health, and environmental effects in their impact assessments. In 2008, a group of U.S. senators—including then-Senator John Kerry, who helped ratify the framework convention on climate change—agreed with this interpretation of the treaty language, saying that “[u]pon signing this treaty, the United States committed itself to considering the global impacts of its greenhouse gas emissions.”<sup>220</sup>

Furthermore, the commenter adds that NEPA requires agencies to administer and interpret the nation’s law to “recognize the worldwide and long-range character of environmental problems” and to “lend appropriate support” to help “maximize

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Power Comm’n, 455 F.2d 412, 424 (2d Cir. 1972) (“The Commission’s ‘hands-off’ attitude is even more startling in view of the explicit requirement in NEPA that the Commission ‘recognize the worldwide and long-range character of environmental problems’ and interpret its mandate under the Federal Power Act in accordance with the policies set forth in NEPA.”).

<sup>215</sup> Draft Update, *supra* note 4, at 15 n.37.

<sup>216</sup> Council on Env’t Quality, National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions and Climate Change, 88 Fed. Reg. 1196, 1203 (Jan. 9, 2023).

<sup>217</sup> S. Treaty Doc. No. 102-38; S. Exec. Rept. No. 102-55.

<sup>218</sup> U.N. Framework Convention on Climate Change art. 3(3), May 9, 1992, 1771 U.N.T.S. 107 (emphasis added); see also *id.* art. 3(1) (“The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities.”) (emphasis added); *id.* art. 4(2)(a) (committing developed countries to adopt policies that account for “the need for equitable and appropriate contributions by each of these Parties to the global effort”).

<sup>219</sup> *Id.* art. 4(1)(f) (emphasis added); see also *id.* art. 3(2) (requiring parties to give “full consideration” to those developing countries “particularly vulnerable to the adverse effects of climate change”); see also North American Agreement on Environmental Cooperation art. 10(7), Jan. 1, 1994, 32 I.L.M. 1480 (committing the United States to the development of principles for transboundary environmental impact assessments).

<sup>220</sup> Comment Letter from U.S. Sens. Feinstein, Snowe, Nelson, Cantwell, Sanders, Kerry, Durbin, Reed, Boxer, & Cardin to Mary Peters, Sec’y, U.S. Dep’t of Transp. on Proposed Rule for Average Fuel Economy Standards, Passenger Cars and Light Trucks; Model Years 2011 2015 (July 1, 2008).

international cooperation.”<sup>221</sup> Numerous court decisions—including one from the U.S. Court of Appeals for the D.C. Circuit—have held that reasonably foreseeable transboundary effects must appear in NEPA analyses.<sup>222</sup> And consistent with those decisions, agencies have assessed transboundary impacts under NEPA for over forty years under Executive Order 12,114, which instructs agencies to “take into consideration in making decisions” effects of their actions on the “environment of a foreign nation” and “the global commons.”<sup>223</sup> The commenter contends that EPA’s consideration of extraterritorial environmental impacts is consistent with decades of agency practice.

***Administrative Procedures Act (APA):*** The commenter (2281-CCES et al) provides that under the APA, it is arbitrary and capricious for agencies to “entirely fail[] to consider an important aspect of the problem”<sup>224</sup>—an obligation that a federal court held requires federal agencies to consider international climate impacts. Specifically, the commenter notes that a recent ruling from the U.S. Court for the Northern District of California struck down as arbitrary the Bureau of Land Management (BLM) rescission of the Waste Prevention Rule in part because the agency had abandoned the Working Group’s peer-reviewed, global estimates of the social cost of GHGs in favor of flawed estimates (the same estimates that EPA applied under the Trump administration) that looked narrowly at effects within the U.S. borders.<sup>225</sup> The Court found that the global values developed by the Working Group reflected “the best available science about monetizing the impacts of greenhouse gas emissions,”<sup>226</sup> whereas “focusing solely on domestic effects has been soundly rejected by economists as improper and unsupported by science.”<sup>227</sup> The Court reminded BLM that relevant executive orders, including Executive Order 12,866, require consideration of “all” costs and benefits, based on the “best reasonably obtainable scientific, technical, economic, and other information,” and concluded that “no[] . . . regulatory rules or orders require exclusion of global impacts.”<sup>228</sup>

***Executive Order 13990 and Other Rulemaking Efforts:*** Commenter (2281-CCES et al) provides that Executive Order 13990 (Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis (2021)) instructed agencies to “tak[e] global damages into account,” because “[d]oing so facilitates sound decision-making, recognizes the breadth of climate impacts, and support the international leadership of the United States on climate issues.”<sup>229</sup> This language again, according to the commenter, reinforces the instructions from NEPA that, whenever not precluded by statute from doing so, agencies should account for the environmental impacts of their actions on foreign nations and global commons.

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<sup>221</sup> 42 U.S.C. § 4332(2)(F)

<sup>222</sup> E.g. *Env’t Def. Fund, Inc. v. Massey*, 986 F.2d 528 (D.C. Cir. 1993); *Gov’t of Man. v. Salazar*, 691 F. Supp. 2d 37, 51 (D.D.C. 2010).

<sup>223</sup> See Exec. Order No. 12,114 § 2–3, 44 Fed. Reg. 1957 (Jan. 4, 1979).

<sup>224</sup> *Motor Vehicle Manufacturers Ass’n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 41–43 (1983).

<sup>225</sup> Bernhardt, 472 F. Supp. 3d at 613.

<sup>226</sup> *Id.* at 611.

<sup>227</sup> *Id.* at 613.

<sup>228</sup> *Id.* at 611–12 (internal quotation marks omitted).

<sup>229</sup> Exec. Order No. 13,990 § 5(a), 86 Fed. Reg. 7037, 7040 (Jan. 20, 2021).

**Historic Precedent:** The commenter (2281-CCES et al) notes that agencies have considered key effects on international reciprocity in their regulatory cost-benefit analyses and decision-making. The commenter describes EPA’s 1988 regulations to protect stratospheric ozone as best antecedent. The commenter provides that, in issuing those regulations, EPA recognized that it could “consider other countries’ willingness to take regulatory action” in “deciding whether and how to regulate.”<sup>230</sup> EPA also took “[c]onsideration of the international ramifications of United States action” into account when “analyzing the cost and feasibility of controls.”<sup>231</sup> And in its regulatory impact analysis (RIA), EPA modeled alternative regulatory stringency levels based on potential international participation rates and the influence that EPA regulation would have on reciprocal international actions.<sup>232</sup> The commenter states that by adopting a global approach to the social cost of GHGs, EPA therefore draws upon the approach that it took for stratospheric ozone under the Reagan administration.

The commenter (2281-CCES et al) adds that on several prior occasions—again outside the context of climate change—Courts have upheld EPA’s authority to consider effects on international reciprocity and cooperation due to domestic pollution standards. In one case, for instance, the D.C. Circuit upheld EPA’s decision to set an interim tolerance of 30 parts per billion (ppb) for the chemical ethylene dibromide under the Food, Drug, and Cosmetic Act (FDCA)—rather than ban the chemical altogether—after EPA concluded that a ban “could damage cooperative [food-safety] efforts,” reasoning that “[s]ince effective enforcement of food safety laws depends upon such cooperation, a ban might increase the risk that fruit and vegetables would enter the U.S. treated with unsafe levels of pesticides or infested with pests or diseases.”<sup>233</sup> The D.C. Circuit similarly upheld EPA’s consideration of international harmonization in setting nitrogen oxide (NOx) emissions standards for commercial aircraft gas turbine engines, after EPA issued a standard under the CAA to align U.S. standards with international standards.<sup>234</sup>

Additionally, commenter (2281-CCES et al) notes agencies have also considered transboundary spillover effects in making key decisions. As one example, when considering the “public interest” in the certification of natural gas exports under the Natural Gas Act,<sup>235</sup> the Department of Energy routinely “consider[s] international trade policy, foreign policy, and national security interests.”<sup>236</sup> As another example, the Food and Drug Administration also frequently considers international effects as part of its

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<sup>230</sup> Protection of Stratospheric Ozone, 53 Fed. Reg. 30,566, 30,569 (Aug. 12, 1988).

<sup>231</sup> Id. (“Certainly other nations’ ozone-depleting emissions or control of emissions affect the cost of United States’ controls, and the need for other nations to limit their emissions may make appropriate United States action that encourages, or does not discourage, other nations to agree to such limits.”).

<sup>232</sup> Env’t Prot. Agency, Regulatory Impact Analysis for the Protection of Stratospheric Ozone (1988).

<sup>233</sup> *National Coalition Against the Misuse of Pesticides v. Thomas*, 815 F.2d 1579, 1582 (D.C. Cir. 1987).

<sup>234</sup> *National Ass’n of Clean Air Agencies v. EPA*, 489 F.3d 1221 (D.C. Cir. 2007).

<sup>235</sup> 15 U.S.C. § 717b(a).

<sup>236</sup> New Policy Guidelines and Delegation Orders from Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6,684, 6,688 (Feb. 22, 1984).

regulatory decision-making, and has recognized that such costs are particularly relevant because “a portion of foreign costs could be passed on to domestic consumers.”<sup>237</sup>

Commenter (2281-CCES et al) states that Courts have confirmed that agencies may—and, in some cases, must—consider international spillover effects. In 2020, the U.S. Court of Appeals for the Ninth Circuit rejected a Bureau of Ocean Energy Management approval of an offshore oil drilling and production facility after the agency concluded that domestic extraction would not affect international fossil-fuel supply and consumption.<sup>238</sup> As the Court explained, because domestic production causes “foreign consumers [to] buy and consume more oil”—and because that consumption “can be translated into estimates of greenhouse gas emissions” that harms the U.S.—the agency had an obligation to consider those increased foreign emissions resulting from domestic action.<sup>239</sup> Two subsequent district court opinions similarly faulted Department of Interior analyses for omitting the effects of domestic production on foreign demand and consumption.<sup>240</sup> The commenter contends that the fact that Courts have required agencies to consider the spillover impacts from foreign GHG emissions provides strong support for EPA’s consideration of spillovers from domestic emissions.

Commenter (2246-NRDC) expresses support for basing the SC-GHG on global economic damage, due to the impact such damages will have on American assets abroad and the global nature of the U.S. economy. The commenter further argues for the adoption of the same global SC-GHG estimate among countries, noting that the alternative – i.e., “if each country accounts solely for the damage caused by its own emissions within its own geographic boundary” – then “in aggregate the severity of the global damage will be severely undercounted, and a global tragedy of the commons would lead to global climate degradation”. The commenter points to recent research for a mathematical proof of this hypothesis.<sup>241</sup> The commenter also points to recent research as providing a detailed justification of the importance of international reciprocity as a reason for adoption a global focus in SC-GHG estimation:

“They explain how other countries, including Canada, Sweden, Germany, and the United Kingdom, have strategically selected a global SC-GHG, that the United States has benefited from other countries’ policies to account for global damage from their own emissions, and, most importantly, they explain how the United States can foster an atmosphere of reciprocity by leading with a global SC-GHG. They explain how economic ‘models of strategic behavior and real-world experiments suggest the United States may be able to stimulate cooperative international action by leading by example;

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<sup>237</sup> Requirements for Additional Traceability Records for Certain Foods, 87 Fed. Reg. 70,910, 71,071 tbl.2 (Nov. 21, 2022).

<sup>238</sup> *Ctr. for Biological Diversity v. Bernhardt*, 982 F.3d 723, 738 (9th Cir. 2020).

<sup>239</sup> *Id.*

<sup>240</sup> *Sovereign Iñupiat for a Living Arctic v. Bureau of Land Mgmt.*, 555 F. Supp. 3d 739, 764–67 (D. Alaska 2021); citing *Friends of the Earth v. Haaland*, No. CV 21-2317 (RC), 2022 WL 254526, at \*14–15 (D.D.C. Jan. 27, 2022).

<sup>241</sup> Matthew Kotchen, Which Social Cost of Carbon? A Theoretical Perspective 7–8 (Aug. 12, 2016), <https://cenrep.ncsu.edu/cenrep/wp-content/uploads/2015/07/Kotchenpaper.pdf> [<https://perma.cc/BH2A-7KGV>] (“The result is intuitive: the marginal benefit of emissions is equated across all countries and equal to the sum of the marginal damages of emissions. . . . That is, all countries must internalize the GSC-GHG [global SC-GHG], which then defines a unique level of Pareto optimal emissions for each country.”).

building trust, a reputation for equity, and a critical mass of initial actors; and promoting a tit-for-tat dynamic of mutually beneficial reciprocity between nations.”<sup>242</sup>

Finally, the commenter (2246-NRDC) suggests that a global SC-GHG estimate is consistent with the Clean Air Act because the Act compels EPA to act on emissions of air pollutants that “may reasonably be anticipated to endanger public health or welfare,” and welfare is expansively defined to include “effects on ... climate.” See, e.g., Clean Air Act §§ 202(a)(1) and 302(h). The commenter argues that since GHGs are air pollutants under the CAA and since the adverse effect of this pollution do not stop at U.S. borders, “there is thus no basis in the statute to limit the scope of “public health” and “welfare” to only those effects manifested inside the Nation’s borders. For these reasons, EPA would fail its legal duty to adequately consider danger to health and welfare if it were to circumscribe its analysis to domestic impacts only.”

Commenter (2410-CA AG et al.) argues that the consideration of global impacts of greenhouse gas emissions is fully within the authority of federal agencies. The commenter cites an example of the consideration of global benefits being upheld in court<sup>243</sup> as well as an example of where the failure to do so was ruled an error in *California v. Bernhardt*, in which the Court noted that “focusing solely on domestic effects has been soundly rejected by economists as improper and unsupported by science.”<sup>244</sup>

Response A-6-1: EPA thanks commenters for their supportive comments and numerous recommendations. EPA has expanded the explanation of why the Agency focuses on SC-CH<sub>4</sub> estimates that provide a global measure of the monetized benefits from CH<sub>4</sub> emission reductions in the final RIA.

Comment: Commenter (2239-Fraas et al.) states that they agree with EPA’s justification for using global SC-GHG estimates. In particular, the commenter states that global SC-GHG estimates “might help to promote future international cooperation and indicate the future scale of international cooperation that fighting climate change may require.” However, the commenter argues that providing both global and country estimates “will increase transparency about who receives the benefits, will foster policy discussions about fairness and equity, will furnish agencies with the flexibility to prepare analyses consistent with their statutory mandates, and will provide important distributional information to help in international negotiations.” The commenter states that presenting both a domestic and a global SCC increases transparency to Congress and U.S. citizens who will bear most of the cost of U.S. emissions reductions policies. The commenter also states that reporting both estimates may “reduce disruptive whipsawing of carbon policy analyses across administrations.”

The commenter (2239-Fraas et al.) further argues that EPA’s justification for only providing a subset of domestic damages is unpersuasive. The commenter argues that there is a rich set of environmental and economic data available in the U.S., and the commenter supports developing

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<sup>242</sup> Howard and Schwartz, *Think Global: International Reciprocity as a Justification for the Global Social Cost of Carbon* (2017), at 221- 232; [https://policyintegrity.org/files/publications/Think\\_Global.pdf](https://policyintegrity.org/files/publications/Think_Global.pdf).

<sup>243</sup> *Zero Zone*, 832 F.3d at 679.

<sup>244</sup> 472 F.Supp.3d 574, 608–14 (N.D. Cal. 2020), *appeal pending* Docket Nos. 20-16794, 20-16801 (9th Cir.).

regional damage estimates within the U.S. as the science improves further. The commenter argues that the inherent uncertainties in a domestic SCC is no greater than the uncertainties in producing a global SCC. The commenter states that a “scientific advisory panel to the EPA recommended soft-linking as an option for incorporating disaggregated spatial environmental information into EPA’s SAGE model (EPA, 2017).”<sup>245</sup> The commenter also argues that the development of a domestic SCC is a natural pre-requisite to being able to conduct environmental justice analyses as recommended by President Biden’s Modernizing Regulatory Review memorandum.<sup>246</sup>

Commenter (2239-Fraas et al.) lastly argues that the “exclusive focus on the global SCC also presumes that U.S. policymakers are indifferent about whether climate-control benefits occur in the U.S. versus elsewhere in the world.” The commenter argues that this view is inconsistent with the Clean Air Act and President Clinton’s 1993 Executive Order on Regulatory Planning and Review.<sup>247</sup> The commenter notes that international cooperation and reciprocity on climate change should be assessed by emissions reductions or binding agreements and not stated goals or pledges. The commenter cites evidence that shows that most countries fail to meet their 2015 Paris Agreement commitments,<sup>248</sup> which were not legally binding.

Response A-6-2: EPA thanks the commenter for their supportive statements about EPA’s justification for using global SC-GHG estimates. EPA agrees with the commenter that transparency and distributional analysis is important in EPA RIAs. EPA is continuously striving to improve its ability to present evidence on the possible distributional effects of climate change in our analyses. In this regard, the SC-GHG Report provides a discussion of the available evidence on the distribution of climate change impacts based on the results from the SC-GHG modeling and related published literature from U.S.-specific modeling efforts. This presentation is also included in the final RIA. Taken together, applying the U.S.-specific partial SC-CH<sub>4</sub> estimates derived from the multiple lines of evidence described in the RIA to the CH<sub>4</sub> emissions reduction expected under the final rule would yield substantial benefits. EPA will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of GHG impacts.

Similarly, EPA is continuously striving to improve its ability to present evidence on the possible effects of climate change in communities with environmental justice concerns. When assessing the environmental justice (EJ) impacts of climate change it is critical to consider not only the marginal impacts of the expected emissions reductions, as is measured by the SC-GHG, but also difference in baseline exposure to the impacts of climate change and interactions with other

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<sup>245</sup> Environmental Protection Agency, 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. EPA-SAB-17- 012

<sup>246</sup> “Modernizing Regulatory Review” The White House. <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/modernizing-regulatory-review/>

<sup>247</sup> Executive Order 12866 of September 30, 1993 “Regulatory Planning and Review” <https://www.archives.gov/files/federal-register/executive-orders/pdf/12866.pdf>

<sup>248</sup> “Climate Commitments Not On Track to Meet Paris Agreement Goals” as NDC Synthesis Report is Published. United Nations. 2021. <https://unfccc.int/news/climate-commitments-not-on-track-to-meet-paris-agreement-goals-as-ndc-synthesis-report-is-published>

socioeconomic and environmental stressors. Furthermore, the framework of EJ analyses does not require monetization of damages as is necessary for inclusion with an estimate of the SC-GHG. Therefore, in the EJ assessment presented in the RIA, the EPA relies on many lines of evidence on the local and regional impacts of climate change and not only those lines of evidence that allow for monetization of the damages. Therefore, EPA disagrees that “that the development of a domestic SCC is a natural pre-requisite to being able to conduct environmental justice analyses” as the purpose and scope of such analyses differs from that of the SC-GHG.

Comment: Several other stakeholders disagree with EPA’s use of global estimates (2428-API, 2227-W. Energy Alliance, 2339-INGAA, 2237-NDIC, 2254-PBPA, 2445-J.K. Davis). Commenters (2237-NDIC, 2339-INGAA, 2428-API) argue that it is inconsistent to measure global benefits of GHG reductions against the domestic costs imposed by U.S. environmental regulations. Commenters (2339-INGAA, 2237-NDIC, 2429-API), argue that EPA’s focus on global estimates may conflict with the Clean Air Act, and commenter (2254-PBPA) argues that Circular A-4 requires EPA to focus on domestic effects of emissions reductions. Commenters (2227-W. Energy Alliance, 2339-INGAA, 2428-API) question whether presenting global estimates of the SC-GHG will engender international reciprocity and argue that countries may instead limit their efforts to reduce GHG emissions in response.

Commenter (2237-NDIC) notes that EPA must assess the Supplemental Proposal based only on domestic costs, as required by the CAA. The commenter writes that when considering the Supplemental Proposal based on solely domestic estimates of SC-GHG, the Proposal is not justified. The commenter also argues that EPA’s authority to advance Section 111 regulations under the CAA is not based in global climate benefits. Instead, Section 111 directs EPA to consider the quantity of air pollutant emission which each category will emit; the extent to which each pollutant may reasonably be anticipated to endanger public health or welfare; and the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance when putting forth standards for new sources. The commenter argues that this direction is clear in that analyses must be based on assumptions related to national, not global, impacts. In addition, the commenter remarks that EPA has not been authorized by Congress to impose national costs for the sake of global benefits.

Commenter (2237-NDIC) asserts that while E.O. 13990 may provide limited guidance on considering the SC-GHGs for public policy purposes, it cannot change or override the statutory requirements established by Congress in the Clean Air Act. The commenter questions the legality of the E.O. if it is interpreted as requiring the exclusion of separate domestic benefits calculations, which they claim violates the CAA. The commenter also criticizes EPA’s cost-benefit analysis for the Supplemental Proposal, claiming that it unfairly imposes costs solely on the U.S. public while claiming global benefits. They emphasize concerns regarding the use of an ideological global SC-GHG metric, which they argue fails to adequately consider the domestic SC-GHGs. The commenter adds that federal agency regulations have been overturned in the past for failing to justify not using *domestic* cost-benefit calculations, as in *Wyoming et al. v. DOI et al.*, 493 F. Supp. 1046.<sup>249</sup>

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<sup>249</sup> 493 F. Supp. 3d 1046 (D. Wyo. 2020).

Commenter (2237-NDIC) criticizes EPA for calculating the domestic SC-GHG in previous benefit-cost analyses but refusing to use those calculations. The commenter highlights that EPA has developed and quantified domestic estimates of the SC-GHG in response to Executive Order 13783. The commenter mentions that benefit-cost analyses, including the one for the Oil and Natural Gas Technical Reconsideration and Policy Review, estimated the domestic SC-GHG to be in the range of \$1 to \$7 per metric ton of carbon dioxide. The commenter argues that even at the high end of the domestic range, the estimated climate benefits of the proposal significantly decrease, while the net burden on the U.S. public increases. The commenter concludes that the Supplemental Proposal is not justified when the domestic SC-GHG is appropriately considered to assess the costs faced by the U.S. public. The commenter argues that EPA should either use the existing domestic calculation or update it, rather than excluding the domestic social costs and relying on speculative global costs.

Commenter (2339-INGAA) expresses that EPA does not justify that the global effects would not be symmetrical to national effects, stating that while U.S. citizens are affected by international climate impacts, foreign citizens are also affected by U.S. domestic climate impacts. The commenter acknowledges that there is likely not perfect symmetry in this respect, but they offer it as a reasonable default assumption. The commenter argues that spillover effects are not a credible justification for the use of global SC-GHG figures. The commenter then disagrees with EPA's reciprocity reasons for a global focus because it is "merely hopeful speculation" and that "[i]f anything, it runs contrary to what rational choice would traditionally predict, i.e., that unilateral action to improve a commons will affirmatively encourage *free riding*, not reciprocity." To support this statement, the commenter cites a research paper<sup>250</sup> as "characterizing a free-riding response as "more probable" than reciprocity" and another study that states that "U.S. GHG policies could lead other countries to become more lax in their policy efforts, reducing U.S. benefits. This means that the implication for reciprocity could be negative."<sup>251</sup>

Commenter (2339-INGAA) argues that use of global SC-GHG estimates can lead to a biased cost-benefit analysis if it does not also consider the "social benefits of energy" over a similar geographic and temporal scope. The commenter writes that EPA's decision to present global estimates of the SC-GHG conflicts with historical standard benefit-cost practice on the part of federal rule makers generally and EPA specifically, noting that EPA in the past has not given equal weighting to citizens of other countries even in matters with cross-border effects (such as mercury or sulfur dioxide pollution). The commenter adds that EPA's decision to increase domestic damage figures due to DSCIM and GIVE's underestimation of domestic GHG mitigation benefits does not pass the "test of rationality in administrative decision-making." Lastly, the commenter suggests that the power to endorse use of global damages over domestic may be outside of EPA's authority, and that where Congress has issued judgement on the matter, EPA must follow it. To that end, the commenter argues that the CAA represents Congressional intent to prioritize domestic over global impacts, with its purpose of protecting and enhancing

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<sup>250</sup> Masur, J. S., & Posner, E. A. (2011). Climate regulation and the limits of cost-benefit analysis. *Calif. L. Rev.*, 99, 1557.

<sup>251</sup> Gayer, T., & Viscusi, W. K. (2016). Determining the proper scope of climate change policy benefits in US regulatory analyses: Domestic versus global approaches. *Review of Environmental Economics and Policy*.



the quality of “the Nation’s” air resources. The commenter also suggests EPA’s use of global damages may be in violation of the major questions doctrine.

Commenter (2339-INGAA) further states that EPA’s focus on the complexity of disaggregating domestic and global effects does not justify their use of global estimates. The commenter states that domestic climate change damages are expected to represent a small percentage of global damages, remarking that estimates have ranged from 14-19% under the previous administration, to 5-12% under EPA’s current DSCIM and GIVE models depending on the emission and year. To that end, the commenter states that EPA’s reasoning for using global estimates is unsatisfactory.

Commenter (2428-API) refers to Section 115 and Title VI of the Clean Air Act (CAA) for characterizations of how to consider international effects of domestic air pollutant emissions. The commenter elaborates that such considerations are limited to 1) scenarios in which there is reciprocity, meaning the United States has the same rights to prevent or control air pollution in that country as given to the other country by Section 115, or 2) consideration of global impacts of ozone-depleting chemicals of concern. Accordingly, the commenter argues that these two characterizations represent the extent of international effects that can be considered when characterizing domestic damages. While expressing opposition to EPA’s consideration of global effects, the commenter suggests that total non-U.S. mortality damages are not a reasonable proxy for impacts on U.S. citizens living abroad. The commenter further argues that if EPA justifies the use of global SC-GHG estimates based on considerations of international reciprocity then EPA must explain why its global emissions projection does not reflect globally coordinated action. The commenter argues that EPA should consider and discuss “[r]easonable alternatives that maintain consistency between the geographic scope and the emissions trajectories.”

Commenter (2227-W. Energy Alliance) cites an article<sup>252</sup> that models individual countries’ “preferred” SCC relative to a theoretical global SCC using game theory and decision science. The commenter discusses that the author finds under this model, “to serve its national interests the United States would be rational to support an internal SCC that is about 75% of the [global SCC].” The commenter states that, while simplistic, the author’s modeling indicates that a country’s national interests do not necessarily align with a global SCC. The commenter concludes that “[p]erhaps there is a policy argument to be made for the United States to internalize a GSCC” but “*that is not a scientific decision but rather a policy choice*”, and even “if political consensus on a global SCC were achieved, which to date hasn’t happened, it would still be rational for there to be policy differences on the value used by U.S. policymakers when establishing U.S. climate, energy, and national defense policies. ...One can argue for [use of a global SCC], but EPA should not suggest its position is the only rational position or simply science based.” The commenter “emphasize that such an important topic as the SCC with such expansive societal implications deserves full public scrutiny and should not be buried in the rulemaking for one industrial sector.”

Commenter (2450-Williams Companies, Inc.) argues that EPA demonstrates an overreliance on global climate effects, which conflicts with proper statutory construction of the CAA. On the one

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<sup>252</sup> “Which Social Cost of Carbon? A Theoretical Perspective,” M. Kotchen, Journal of the Association of Environmental and Resource Economists, volume 5, number 3, 2018.

hand, the commenter suggests that Section 111 is, at most, silent on whether global climate calculus is appropriate when developing emission controls. The commenter contends EPA has misconstrued such silence as a conferral of authority to broadly rely on global estimates when drafting standards that should otherwise be based on domestic considerations. For instance, the commenter states that a plain reading of CAA's language imparts a clear mandate on EPA to lead "reasonable Federal, State, and local government actions . . ."<sup>253</sup> In that capacity, the commenter adds, the agency's role is to act as "the primary regulator of *domestic* greenhouse emissions."<sup>254</sup> Consonantly, the commenter asserts that this domestic mandate is reinforced by OMB guidance under Circular A-4 (2003), which instructs agencies to "focus on the benefits and costs that accrue to citizens and residents of the United States" with only ancillary focus, if any focus at all, on international concerns.<sup>255</sup> According to the commenter, EPA's rationale for departing from the aforementioned precedent is based on 1) the revocation of Executive Order 13783 and 2) EPA's disagreement with the prior administration's reliance on what the agency claims are faulty domestic emissions calculi. The commenter asserts that neither of those justifications furnish EPA with the authority to enlarge the CAA and rely on global climate damages to the extent the agency did when it drafted this proposal.

Commenter (2254-PBPA) argues that OMB Circular A-4 (2003) bounds EPA to use domestic effects as the basis of the Agency's BCA. The commenter notes that contrary to Federal courts' instructions – which require EPA to separate global considerations from domestic – EPA relied on global effects in developing its estimates.

Commenter (2445-J.K. Davis) emphasizes that the primary objective of regulatory analysis should be to assess the impact on the United States, given the lawful territorial reach of a federal regulator. The commenter argues that EPA's expansion of its social cost analysis globally is neither legally nor logically justified and is an example of arbitrary agency action.

Response A-6-3: Some commenters argue that the EPA's use of global SC-GHG estimates – either the IWG recommended interim estimates or EPA's updated estimates – to monetize the climate benefits expected from this action is inappropriate because EPA is precluded from considering international climate impacts under the Clean Air Act (CAA). Other comments argue that EPA's focus on global SC-GHG estimates in the RIA is not well reasoned or is inconsistent with OMB guidance for regulatory analysis under E.O. 12866. EPA disagrees with both assertions and discusses each in turn.

First, EPA disagrees with commenters who stated that EPA has no authority to consider the international climate benefits of this action, taken pursuant to the Clean Air Act (CAA). As an initial matter, commenters misunderstand the basis for this action. As explained in Section XVI.E of the preamble, this action is justified under the EPA's record-based analysis of the statutory factors of CAA section 111, and the monetized benefits analysis is not used to justify this action. However, to the extent a reviewing court were to conclude, contrary to the EPA's express position, that the presentation of these monetized climate benefits in fact constitutes a

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<sup>253</sup> 42 U.S.C. § 7401(c).

<sup>254</sup> *City of New York v. Chevron Corp.*, 993 F.3d 81, 99 (2d Cir. 2021) (emphasis added).

<sup>255</sup> OMB Circular A-4 (2003), Section E: Identifying and Measuring Benefits and Costs, available at [https://www.whitehouse.gov/wp-content/uploads/legacy\\_drupal\\_files/omb/circulars/A4/a-4.pdf](https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf)

reviewable portion of the record for this action, the EPA explains here in the alternative, that the consideration of global monetized benefits using SC-CH<sub>4</sub> estimates would be lawful under the CAA.

EPA notes that when the Agency is directed to consider costs under the CAA, it does not consider costs on a nationality basis but rather, typically, cost is considered at the facility or firm level without respect to which entity owns or operates the facility(s) or firm(s). Further, EPA's cost estimates in RIAs, including the cost estimates contained in the Final RIA for this rule, regularly do not differentiate between compliance costs expected to accrue to U.S. firms versus foreign interests.<sup>256</sup>

The Act as a whole does not have an exclusively domestic focus. It allows consideration of international effects where rulemakings have international consequences and does not narrowly focus only on harms occurring within U.S. borders. For example, in CAA section 115 and Title VI, Congress demonstrated its intent that EPA address transboundary effects of air pollution. Section 111 of the CAA charges EPA with regulating "air pollution which may reasonably be anticipated to endanger public health or welfare," and "welfare" is defined to include "effects on...weather...and climate."<sup>257</sup> Case law supports addressing global harms specifically under similar language in the CAA. For example, in *Massachusetts v. EPA*, 549 U.S. 497 (2007), the Court found that "there is nothing counterintuitive to the notion that EPA can curtail the emission of substances that are putting the global climate out of kilter." As another example, in *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 120 (D.C. Cir. 2012), the Court held that the CAA's prevention of significant deterioration program was "meant to address a much broader range of harms," including "precisely the types of harms caused by greenhouse gases." Case law also more broadly supports the use of a global SC-GHG estimate when setting a national policy that will have global effects on climate change. For example, in *Zero Zone, Inc. v. Dep't of Energy*, 832 F.3d 654, 679 (7th Cir. 2016), the Court rejected a petitioner's challenge to DOE's use of a global, rather than domestic, social cost of carbon in setting a national efficiency standard under the Energy Policy and Conservation Act, holding that DOE had reasonably identified carbon pollution as "a global externality" and concluding that, because "national energy conservation has global effects, . . . those global effects are an appropriate consideration when looking at a national policy." Notably, when Congress defined "welfare" under the CAA to include "effects on...climate," Congress understood that adverse climate effects could occur on a global scale.<sup>258</sup> The global effects of GHG emissions are an important aspect of the problem, and it is appropriate, if not required, that if the use of SC-GHG is

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<sup>256</sup> For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, the EPA acknowledged that some portion of regulatory costs will likely "accru[e] to entities outside U.S. borders" through foreign ownership, employment, or consumption (EPA 2018, p. 3-13). In general, a significant share of U.S. corporate debt and equities are foreign-owned, including in the oil and gas industry.

<sup>257</sup> 42 U.S.C. § 7602(h); *Massachusetts v. EPA*, 127 S. Ct. 1438, 1447 (2007).

<sup>258</sup> See Richard L. Revesz, Bostock and the End of the Climate Change Double Standard, 46 COLUM. J. ENV'T L. 1, 9 (2020) (detailing the extensive relevant legislative history, including that "[d]uring debate on the 1970 Amendments, which added the terms 'climate' and 'weather' to the definition of 'welfare,' Senator Boggs introduced into the record a White House Report stating that: 'Air pollution alters climate and may produce global changes in temperature. . . . [T]he addition of particulates and carbon dioxide in the atmosphere could have dramatic and long-term effects on world climate.' This evidences an affirmative awareness of the problem of global climate change at the time Congress added the words 'climate' and 'weather' to the definition of 'welfare.'").

considered a part of the administrative record for this action, that EPA assess global effects, i.e., global monetized benefits, in applying the SC-GHG.<sup>259</sup> The only way to protect health and welfare in the U.S. from climate change impacts is to address climate change on a global scale, because it is a global pollution problem. Harmonization of U.S. regulatory policy with international effort can, where consistent with domestic legal authority, be a valid consideration.<sup>260</sup>

Second, EPA disagrees with the comments suggesting that EPA's decision to use and focus attention on global SC-GHG estimates when monetizing the climate benefits in the RIA for this action was not well reasoned or inconsistent with OMB guidance for regulatory analysis under E.O. 12866. As summarized in this section and discussed in greater detail in the SC-GHG Report and Final Rule RIA, the EPA focuses on the global value of climate change impacts when analyzing policies that affect GHG emissions because of the distinctive global nature of the climate change problem.

Unlike many environmental problems where the causes and impacts are distributed more locally, GHG emissions are a global externality making climate change a true global challenge. GHG emissions contribute to damages around the world regardless of where they are emitted. Thus, international cooperation and reciprocity are essential to successfully addressing climate change, as the global nature of greenhouse gases means that a ton of GHGs emitted in any other country harms those in the U.S. just as much as a ton emitted within the territorial U.S. Assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S.

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<sup>259</sup> *Id.* The Federal government also regularly considers international effects in non-CAA contexts, including effects on international reciprocity. *See, e.g.* The National Environmental Policy Act (NEPA), which directs Federal agencies to recognize the worldwide and long-range character of environmental problems” and “maximize international cooperation.” *See* 42 U.S.C. 4321, 4331(a), (b)(1), and 4332(F). Notably, these relevant provisions in NEPA do not just apply narrowly to agencies’ productions of environmental impact statements; rather, agencies are much more broadly instructed “to the fullest extent possible[,] the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter,” 42 U.S.C. 4332(1), including the need to “recognize the worldwide and long-range character of environmental problems.” 42 U.S.C. 4332(2)(F). In other words, NEPA supports agency interpretations of applicable laws in ways that recognize the worldwide character of environmental problems.

<sup>260</sup> Note that the United Nations Framework Convention on Climate Change—to which the United States is a party, S. Treaty Doc. No. 102-38; S. Exec. Rept. No. 102-55—declares that national “policies and measures to deal with climate change should be cost-effective so as to ensure global benefits at the lowest possible cost,” committing parties to consider the global benefits of their actions. U.N. Framework Convention on Climate Change art. 3(3), May 9, 1992, 1771 U.N.T.S. 107 (emphasis added); *see also id.* art. 3(1) (“The Parties should protect the climate system for the benefit of present and future generations of humankind, on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities.”) (emphasis added); *id.* art. 4(2)(a) (committing developed countries to adopt policies that account for “the need for equitable and appropriate contributions by each of these Parties to the global effort”). *See also* Protection of Stratospheric Ozone, 53 Fed. Reg. 30,566, 30,569 (Aug. 12, 1988) (EPA may consider “the effect of United States action on other countries’ willingness to take regulatory action.”); *National Ass’n of Clean Air Agencies v. EPA*, 489 F.3d 1221 (D.C. Cir. 2007) (upholding EPA’s consideration of international harmonization in setting NOx emissions standards for commercial aircraft gas turbine engines, after EPA issued a standard under the Clean Air Act to align U.S. standards with international standards.)

citizens and residents. This is a classic public goods problem because each country's reductions benefit everyone else, and no country can be excluded from enjoying the benefits of other countries' reductions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis — and so benefit the U.S. and its citizens and residents — is for all countries to base their policies on global estimates of damages. If each country were to design policies to equate marginal damages with marginal abatement costs using only the damages inflicted on their own citizens and residents, the world would not achieve the socially optimal level of emissions; each country would be relatively worse off from the impact of foreign emissions.<sup>261</sup>

As discussed in the SC-GHG report, the EPA's focus on global SC-GHG estimates is consistent with a wide range of scientific and economic experts who have emphasized the issue of international cooperation and reciprocity as support for assessing global damages of GHG emission in domestic policy analysis. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to also assess global climate damages of their policies and to take steps to reduce emissions. For example, many countries and international institutions have already explicitly adapted the global SC-GHG estimates used by EPA in their domestic analyses (e.g., Canada, Israel) or developed their own estimates of global damages (e.g., Germany), and recently, there has been renewed interest by other countries to update their estimates since the draft release of the updated SC-GHG estimates presented in the December 2022 Supplemental Proposal RIA.<sup>262</sup> In addition, as discussed in the SC-GHG Report several studies have empirically investigated international GHG mitigation reciprocity, through both policy diffusion and technology diffusion effects.

A few commenters questioned whether presenting global estimates of the SC-GHG would engender international reciprocity and argue that countries may instead limit their efforts to reduce GHG emissions in response. EPA disagrees that such "free-riding" would be the more likely outcome and notes that recent research does not find support for a free-rider hypothesis in the context of climate policy. For example, Schmidt et al. (2022)<sup>263</sup>, using data on emission-weighted carbon prices while controlling for a variety of other potential explanatory variables, find that the evidence does not support the presence of free riding. EPA also notes that one commenter's quote from a study to substantiate the commenter's argument for free-riding omitted a key sentence from the study that ran counter to the commenter's claim. The authors of

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<sup>261</sup> As one public commenter (in their comments to OMB on the Proposed Revisions to Circular A-4) explained: "...US greenhouse gas emissions account for about 12 percent of the global total. If all countries considered only the domestic effects of their greenhouse gas emissions, about 88 percent of climate change impacts on US citizens would be ignored. An analytic focus solely on direct impacts to the United States of US emissions, when generalized, therefore omits most of the total climate impacts the United States faces" (<https://www.rff.org/publications/testimony-and-public-comments/comments-on-the-proposed-revisions-to-circular-a-4/>).

<sup>262</sup> In April 2023, the government of Canada announced the publication of an interim update to their SC-GHG guidance, recommending SC-GHG estimates identical to the EPA's updated estimates presented in the December 2022 Supplemental Proposal RIA. The Canadian interim guidance will be used across all federal departments and agencies, with the values expected to be finalized by the end of the year. <https://www.canada.ca/en/environment-climate-change/services/climate-change/science-research-data/social-cost-ghg.html>.

<sup>263</sup> Schmidt, R.C., Drupp, M., Nesje, F. and Hoegen, H., 2022. Testing the free-rider hypothesis in climate policy. *arXiv preprint arXiv:2211.06209*.

the study stated “U.S. GHG policies could lead other countries to become more lax in their policy efforts, reducing U.S. benefits. This means that the implication for reciprocity could be negative. *Given ongoing international efforts, a more likely scenario is that the reciprocity value is positive* [emphasis added].”<sup>264</sup>

For all of these reasons, the EPA believes that a global metric is appropriate for assessing the climate benefits of avoided methane emissions in the final RIA. In addition, as emphasized in the National Academies (2017) recommendations, “[i]t is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States.” The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to U.S. citizens and residents. Examples of affected interests include, direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. These impacts point to another dimension of the global nature of the climate change problem and are better captured within global measures of the social cost of greenhouse gases.

To summarize, in the case of this global pollutant, the assessment of global net damages of GHG emissions allows EPA to fully disclose and contextualize the net climate benefits of the CH<sub>4</sub> emission reductions expected from this final rule. This approach is the same as that taken in EPA regulatory analyses from 2009 through 2016 and since 2021. Contrary to some commenters’ assertions, it is also consistent with guidance in OMB Circular A-4 (2003) that states when a regulation is likely to have international effects, “these effects should be reported.”<sup>265</sup> Furthermore, given that it is in the U.S. interest to account for the global consequences of a global pollutant like CH<sub>4</sub>, EPA believes there is no inherent inconsistency in comparing monetized climate benefits based on global SC-CH<sub>4</sub> estimates to the estimated costs anticipated from a regulatory action in regulatory benefit-cost analysis. Importantly, EPA notes that the cost

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<sup>264</sup> Gayer, T., & Viscusi, W. K. (2016). Determining the proper scope of climate change policy benefits in US regulatory analyses: Domestic versus global approaches. *Review of Environmental Economics and Policy*.

<sup>265</sup> While OMB Circular A-4 recommends that international effects be reported separately, the guidance also explains that “[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues.” Circular A-4 (2023) states that “In certain contexts, it may be particularly appropriate to include effects experienced by noncitizens residing abroad in your primary analysis. Such contexts include, for example, when:

- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. citizens and residents that are difficult to otherwise estimate;
- assessing effects on noncitizens residing abroad provides a useful proxy for effects on U.S. national interests that are not otherwise fully captured by effects experienced by particular U.S. citizens and residents (e.g., national security interests, diplomatic interests, etc.);
- regulating an externality on the basis of its global effects supports a cooperative international approach to the regulation of the externality by potentially inducing other countries to follow suit or maintain existing efforts; or
- international or domestic legal obligations require or support a global calculation of regulatory effects” (OMB 2023). See also footnote 12 of Circular A-4 (2023) (discussing the SC-GHG specifically).

estimates contained in EPA RIAs do not distinguish and segregate the share of compliance costs that accrue to foreign interests.<sup>266</sup>

Finally, the EPA disagrees with commenters who suggest that the EPA should focus on a metric of benefits resulting solely from changes in climate impacts occurring within U.S. borders (typically referred to as a “domestic” SC-GHG). As explained in the final RIA, the global models used in the SC-GHG modeling do not lend themselves to being disaggregated in a way that can provide comprehensive information about the distribution of the rule's climate benefits to citizens and residents of particular countries, or population groups across the globe and within the U.S. However, as EPA is continuously striving to improve the ability to present evidence on the possible distributional effects of climate change in our analyses, the SC-GHG Report provides a discussion of the available evidence on the distribution of climate change impacts based on the results from the SC-GHG modeling and related published literature from U.S.-specific modeling efforts (such as the FrEDI model described in the Final rule). This presentation is also included in the final RIA for this action. EPA notes that, contrary to some commenters’ claims, previous EPA RIAs – including the November 2021 Proposal RIA and the December 2022 Supplemental Proposal RIA – have also included a presentation of a rule’s climate benefits resulting from climate impacts occurring within the territorial United States to the extent that they were represented in the IWG’s SC-GHG modeling framework, along with an explanation of the inadequacy of such estimates in measuring damages to U.S. citizens and residents.

As discussed in the final RIA, taken together, applying the U.S.-specific partial SC-CH<sub>4</sub> estimates derived from the multiple lines of evidence described in the RIA to the CH<sub>4</sub> emissions reduction expected under the final rule would yield substantial climate benefits – even given the numerous explicitly omitted damage categories and other modeling limitations that make it likely that these estimates underestimate the benefits from CH<sub>4</sub> emission reductions. The EPA has expanded the discussion of omitted and partially modeled damage categories and other modeling limitations in the SC-GHG Report in response to public comments and peer reviewer recommendations. The EPA will also continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of GHG impacts.

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<sup>266</sup> For example, in the RIA for the 2018 Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources, the EPA acknowledged that some portion of regulatory costs will likely “accru[e] to entities outside U.S. borders” through foreign ownership, employment, or consumption (EPA 2018, p. 3-13).

## A.7 Process of Developing SC-GHG Estimates

Comment: Commenters (2398-Policy Integrity NYU, 2246-NRDC) discuss the process for updating the SC-GHG estimates and request that updates be made regularly. The commenters urge EPA to update its integrated assessment model and corresponding SC-GHG estimates every 5 years, consistent with the National Academies (2017) recommendation, because this update cycle would appropriately balance the benefit of evolving research with the need for a regular process. The commenters further note that the damage functions could be updated more frequently as improvements become available.

Commenter (2355-Constellation) expressed support for the use of EPA's SC-CH<sub>4</sub> estimates in the Supplemental Proposal RIA and notes that “[a]s a critical member of the IWG, EPA is an agency with technical and economic expertise that makes it well-suited to establish a social cost of greenhouse gases.” The commenter recommends that the updated estimates inform the continued work of the IWG and “encourage[s] coordination among agencies for consistent application of a social cost of greenhouse gases to provide certainty to the regulated community, avoid confusion, and ensure that all federal regulations reflect the benefits of climate change mitigation.”

Response A-7-1: The EPA thanks the commenters for these recommendations. EPA is committed to making evidence-based decisions pertaining to the methodologies used in EPA analyses, guided by the best available science and input from the public and peer reviewers. Thus, as noted in previous EPA regulatory impact analyses and again in the RIA for this final rule, the EPA will continue to review developments in the scientific literature, including more robust methodologies for estimating the magnitude of the various direct and indirect damages from GHG emissions, and look for opportunities to further improve SC-GHG estimation going forward. The final SC-GHG report discusses areas where additional research is needed to model climate change impacts and associated damages that are not yet represented in the damages module and to address other longer-term recommendations from the National Academies. The EPA agrees with the commenters and the National Academies peer review panel that a 5-year updating cycle would appropriately balance the benefit of incorporating evolving research with the need for a regular process. Finally, the EPA continues to participate in the IWG's work under E.O. 13990. EPA's technical report along with the peer review of the report will be among the many technical inputs available to the IWG as it continues its work.

Comment: Some commenters raise concerns about the adequacy of the public comment opportunities offered on the SC-GHG estimates used in the Supplemental Proposal RIA.

Commenters (2227-W. Energy Alliance, 2237-NDIC, 2428-API, 2339-INGAA) express that, considering the complexity of the rulemaking, the comment period was not adequate for the public, regulated industry, or other interested parties to provide proper comment. Commenters (2237-NDIC, 2428-API) emphasize the importance of adhering to the review and comment provisions, including a sound interpretation of APA. Commenter (2237-NDIC) expresses that EPA's use of the IWG's values on a global scale without following the notice and comment provisions of the Administrative Procedure Act (APA) constitutes a violation. The commenter argues that “[a]ny action by the Executive Branch in setting binding values for the SC-GHG, that



were established pursuant to a legitimate delegation of authority from Congress, are subject to the requirements of the [APA]”.

Similarly, commenter (2254-PBPA) argues that the lack of an adequate public comment process as well as limited transparency undermines the APA. The commenter states that the use of the SCC “undermines the APA’s public notice requirement by hiding the true costs of this rule behind mischaracterized climate benefits that appear to vastly outweigh any costs. By creating a one-sided and thumb-on-the-scale cost benefit analysis, EPA has made it difficult for the public to understand the costs of its proposal.” Commenter (2227-W. Energy Alliance) states the length and complexities of the SC-GHG Report and SC-CH<sub>4</sub> estimates that affect many industries, it was inappropriate for the document to be buried in an appendix within another complex rulemaking that is targeted to one industry. Further, the commenter wonders why EPA attempted to calculate SCC in the rulemaking without a public engagement plan.

Commenter (2428-API) expresses appreciation for EPA’s willingness to accept comments on the SC-GHG Report as recommended by the National Academies and states that certain aspects of the process, such as EPA’s approach to taking public comment and committing to peer review, are consistent with the principles of President Biden’s Executive Orders. However, the commenter states that EPA should have engaged with interested stakeholders during its revisions to update the four modules in the SC-GHG Report instead of postponing public comment until each module was updated and the SC-GHG Report was drafted. Further, given the extensive new data and analysis reflected in the revised report, the commenter states the 69-day comment period was insufficient for soliciting detailed and comprehensive feedback from stakeholders. The commenter requests EPA provide a new and substantially longer comment period for the SC-GHG Report exclusively, and the estimates contained therein.

Similarly, commenter (2361-EPRI) suggests that after revisions are made to the draft SC-GHG methodology and documentation, a separate dedicated public comment period for the revised draft methodology, and a peer review appropriate for a regulatory methodology with significant implications, should occur. This will give “the public and scientific community confidence in the results and decisions they inform.” The commenter states that currently, how the public is engaged and how input will be used is unclear. The commenter recommends: establishing a clear public engagement process; opportunities to comment in all phases; opportunities for public input into the peer review process, and a definition between the public input and the peer review process.

Response A-7-2: EPA disagrees with the commenters’ assertions that EPA has provided insufficient public comment opportunities on either the IWG recommended interim SC-GHG estimates or on EPA’s draft updated SC-GHG values.

The interim SC-GHG estimates recommended by the IWG in February 2021 are the same as the values developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation. Those estimates were subject to public comment in a dedicated OMB led public comment period in 2013 and in the context of dozens of EPA proposed rulemakings. For example, EPA solicited comment on the SC-CH<sub>4</sub> estimates when used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and

Heavy-Duty Engines and Vehicles–Phase 2 (EPA and DOT, 2015<sup>267</sup>), and again when the estimates were first used in the primary benefit-cost analysis for a number of proposed rulemakings in 2015 (EPA 2015a<sup>268</sup>, 2015b<sup>269</sup>). In addition, the public has had opportunity to comment on the interim IWG estimates following their use in EPA regulatory analyses for numerous proposed rulemakings published since the release of the February 2021 TSD, including in the November 2021 Proposal RIA and the December 2022 Supplemental Proposal RIA.

With respect to EPA’s draft updated SC-GHG estimates, the EPA identified 55 unique substantive public comment submissions to the docket that were relevant to the estimates presented in sensitivity analysis in the December 2022 Supplemental Proposal RIA and the External Review Draft of the SC-GHG Report that was provided as Supplementary Material to the RIA. The EPA is responding to these comments in this RTC. The EPA also conducted an external expert peer review of the External Review Draft of the SC-GHG Report consistent with the guidelines set forth in EPA’s Peer Review Handbook 4th Edition, 2015.<sup>270</sup> The public comments received on the Supplemental Proposal RIA were also available to the peer reviewers as they conducted their review. Several of the peer reviewers even cited public comments pertaining to the draft updated SC-GHG estimates in their recommendations. The EPA posted a recording of the public meeting of the peer review panel on the webpage and posted the final peer review report following its completion in May 2023.

Finally, the EPA disagrees that either the IWG interim SC-GHG estimates or the EPA’s draft updated SC-GHG values are themselves a final agency action under the APA. These figures are included in the final RIA for this particular action pursuant to the EPA’s responsibility under E.O. 12866 to provide monetized benefit-cost analysis for significant regulations.

Comment: Commenters (2428-API, 2445-J.K. Davis) argue that EPA’s development of SC-GHG estimates was not transparent.

Commenter (2428-API) states that there are different versions of the RIA in the rule docket and that aspects of the draft RIA – including discussion of the draft updated SC-GHG estimates and sensitivity analysis – “were deleted in their entirety without explanation shortly before the publication of the Proposed NSPS Revisions.” The commenter stated that “the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the

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<sup>267</sup> U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT), 2015. Draft Regulatory Impact Analysis: Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2. June. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100MKYR.PDF?Dockey=P100MKYR.PDF>

<sup>268</sup> U.S. Environmental Protection Agency (EPA), 2015a. Regulatory Impact Analysis for the Proposed Revisions to the Emission Guidelines for Existing Sources and Supplemental Proposed New Source Performance Standards in the Municipal Solid Waste Landfills Sector. August. <https://www.regulations.gov/document?D=EPA-HQ-OAR-2014-0451-0086>

<sup>269</sup> U.S. Environmental Protection Agency (EPA), 2015b. Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector. EPA-452/R-15-002. August. <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-5258>

<sup>270</sup> U.S. Environmental Protection Agency Peer Review Handbook 4th Edition. 2015. Science and Technology Policy Council U.S. Environmental Protection Agency. Washington, D.C. 20460 [https://www.epa.gov/sites/default/files/2020-08/documents/epa\\_peer\\_review\\_handbook\\_4th\\_edition.pdf](https://www.epa.gov/sites/default/files/2020-08/documents/epa_peer_review_handbook_4th_edition.pdf)

subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis. Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA." The commenter argues that "the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions." The commenter urges EPA to provide access to the records including data and studies used in reaching EPA's conclusions, pursuant to the Clean Air Act (CAA). Specifically, the commenter requests that EPA identify the comments it received on individual EPA proposed rulemakings and the IWG's February 2021 TSD about the IWG's interim SC-GHG estimates that influenced aspects of the EPA's SC-GHG Report. The commenter also requests that more of the studies cited in the SC-GHG report be added to the docket, such as the documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort.

Similarly, commenter (2445-J.K. Davis) expresses the need for reproducibility as a necessary condition for transparency. The commenter (2445-J.K. Davis) suggests EPA should withdraw the report as it doesn't provide materials needed for an independent replication.

Response A-7-3: The EPA provided the public with extensive documentation supporting the draft updated SC-GHG estimates used in the sensitivity analysis in the December 2022 Supplemental Proposal RIA. In the rule docket, EPA provided copies of all studies and reports cited in the RIA, including references cited in the RIA Appendix that presented the sensitivity analysis. This included studies explaining the RFF modeling effort (e.g., Rennert et al. 2022a<sup>271</sup>, 2022b<sup>272</sup>) as requested by one commenter. In addition, the RIA pointed the reader to the dedicated EPA webpage (<https://www.epa.gov/environmental-economics/scghg>) for more information about the development of the estimates. The webpage provides instructions and computer code for the SC-GHG estimates presented in the Draft Report allowing for independent replication and providing additional information about the peer review process. Finally, the EPA disagrees with the commenter's assertion that EPA solicited public comment on two different versions of the Supplemental Proposal RIA. The EPA only takes comment on the final version of an RIA accompanying a proposed rule. As required by the Clean Air Act, EPA docketed documentation on all changes made to the rulemaking package during the interagency review process.

Comment: Some commenters (2428-API, 2399-GPA Midstream Association) argue that they have not received a response to previous comments they made regarding the IWG interim estimates.

Commenter (2428-API) claims that neither the IWG nor EPA responded to or meaningfully considered their comments on the IWG's interim SC-GHG estimates submitted to OMB in 2021,

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<sup>271</sup> Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. *Brookings Papers on Economic Activity*. Fall 2021, pp.223-305.

<sup>272</sup> Rennert, K., Errickson, F., Prest, B.C., Rennels, L., Newell, R., Pizer, W., Kingdon, C., Wingenroth, J., Cooke, R., Parthum, B., Smith, D., Cromar, K., Diaz, D., Moore, F., Müller, U., Plevin, R., Raftery, A., Ševčíková, H., Sheets, H., Stock, J., Tan, T., Watson, M., Wong, T., and Anthoff, D., 2022b. Comprehensive evidence implies a higher social cost of CO<sub>2</sub>. *Nature*. 610(7933), 687-692.

in particular comments about “the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG alongside global values”. The commenter argues that as a key member of the IWG, the EPA has an obligation to address the arguments raised before it, and since the subject of API’s 2021 comments are still present in the EPA’s SC-GHG report, “EPA plainly ignored API’s comments”. Lastly, the commenter states “while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received”. The commenter claims that the Agency’s solicitation of comments at this point is not a sufficient allowance for public participation and engagement with stakeholders that the National Academies recommended.

Commenter (2399-GPA Midstream Associates) expresses that the Administration has not responded to comments submitted by the commenter and others that identified deficiencies in the IWG’s interim SC-CH<sub>4</sub> figures used to estimate projected climate and health benefits in the Supplemental Proposed Rule. which largely require further scientific study. The commenter states that until the peer review process is conducted and subject to public review and comment, it is inappropriate for EPA to consider the interim values to support its Supplemental Proposed Rule.

Response A-7-4: As discussed previously in this section, the interim SC-GHG estimates recommended by the IWG in February 2021 and used in the primary benefit-cost analysis in both the November 2021 Proposal RIA and the December 2022 Supplemental Proposal RIA are the same as the values developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation. Those estimates were subject to public comment in a dedicated OMB led public comment period in 2013 and in the context of dozens of EPA proposed rulemakings that used the estimates. The EPA responded to the comments received within final rulemakings that used the estimates. For example, EPA responded to public comments on the SC-CH<sub>4</sub> estimates in Response to Comments on the 2016 Final Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2,<sup>273</sup> the 2016 Final Rulemaking for Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, and the 2016 Final Rulemaking for Revisions to the Emission Guidelines for Existing Sources and Supplemental Proposed New Source Performance Standards in the Municipal Solid Waste Landfills Sector. In addition, EPA has responded to public comments received on the IWG estimates in final rulemakings published since the release of the February 2021 TSD, such as the December 2021 Final Rulemaking for Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emission Standards.<sup>274</sup> In responding to previous comments, EPA has expressed disagreement with arguments made by commenters – for example, regarding discount rates, time horizons, and the global focus of the SC-GHG estimates - but has not ignored the comments EPA has received on the IWG estimates. To the extent that the comments on these topics were raised in this rulemaking proceeding, the Agency is providing responses on these issues here, consistent with its longstanding practice of addressing public comments on its RIA accompanying rulemaking actions.

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<sup>273</sup> <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100P8IS.PDF?Dockey=P100P8IS.PDF>

<sup>274</sup> <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013NRH.pdf>

Finally, contrary to one commenter's assertion that "nowhere does EPA represent that the report is in draft form", the EPA clearly labeled the report as an "external review draft" in the Supplemental Proposal Preamble, the Supplemental Proposal RIA (p. 189), and in the Supplementary Material to the RIA, which was titled "External Review Draft of the Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances". In the Supplemental Proposal Preamble, the EPA "invite[s] the public to comment on both the sensitivity analysis of the monetized climate benefits and the accompanying external review draft technical report that the EPA has prepared that explains the methodology underlying the newer set of SC-CH<sub>4</sub> estimates... The monetized climate benefits calculated using the SC-CH<sub>4</sub> are included in the benefit-cost analysis, and thus, as is generally the case with any analytical methods, data, or results associated with RIAs, the EPA welcomes the opportunity to continually improve its understanding through public input on these estimates."

Comment: Some commenters questioned the relationship between EPA's update and the IWG process under E.O. 13990.

Commenters (2301-U.S. Chamber of Commerce, 2428-API) express confusion about why EPA operated outside of the IWG process. Commenters (2339-INGAA, 2428-API, 2361-EPRI, 2237-NDIC, 2254-PBPA) argue that EPA acted in violation of Executive Order 13990. Commenter (2450-Williams Companies, Inc.) argues that EPA does not sufficiently explain "why the agency departed from the process set forth in EO 13990, why it felt compelled to act independently of the IWG, of which it is a member, or why the IWG's Interim Estimates were inadequate for this rulemaking analysis."

Commenters (2428-API, 2339-INGAA) highlight that EPA, despite being a member of the Interagency Working Group on the Social Cost of Greenhouse Gases, has developed its own agency-specific SC-GHG estimates in the SC-GHG Report. The commenters view this development as incompatible with the unified approach promised by the Biden administration and as contrary to E.O. 13990. The commenters emphasize that the IWG's development of a SC-GHG highlights the multiple areas of expertise needed to perform such calculations, which is not likely found in a single agency like EPA.

Commenter (2339-INGAA) suggests that EPA's use of its own SC-GHG estimates in regulatory analysis conflicts with E.O. 13990, deviates from the IWG process, and creates regulatory uncertainty for industry. Specifically, the commenter states that EPA violates the following components of E.O. 13990: (1) The IWG shall proceed by publishing interim SC-GHG figures within 30 days and final SC-GHG figures by January 2022, and (2) the IWG shall provide recommendations regarding "a process for reviewing and, as appropriate, updating" the SC-GHG estimates and the underlying methodologies on which they are based, and most critically, (3) that agencies shall use the IWG's interim SC-GHG estimates "when monetizing the value of changes in greenhouse gas emissions." The commenter states that EPA has acted contrary to those instructions by issuing and employing its own entirely different SC-GHG estimates. Specifically, the commenter believes that EPA is supposed to work as a member of the IWG, and not promulgate its own unilateral issuances in contradiction to the process contemplated in E.O. 13990. The commenter recommends that EPA ceases use of these SC-GHG estimates in decision making and revoke its Draft Report.

Commenter (2361-EPRI) raises concerns over EPA's issuance and use of its own new SC-GHG estimates being procedurally improper. Specifically, concerns involve violation of Executive Order 13990, undermining the purpose for which the IWG was established, and the creation of an unnecessary and harmful regulatory uncertainty for the industry.

Commenter (2428-API) expressed concern that, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, other federal agencies may utilize the estimates in EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. The commenter noted that although E.O. 13990 requires agencies use the IWG's values, EPA's lack of a clear statement of "what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts."

Commenter (2301-U.S. Chamber of Commerce) expresses support for the appropriate consideration of GHG emissions as part of benefit-cost analyses under E.O. 12866 and reemphasizes their June 2021 comments to the IWG on the need for an open, transparent, and centralized IWG process and urges continued efforts to promote those values. The commenter noted that following the IWG's release of interim SC-GHG estimates and the accompanying Technical Support Document in February 2021, they were encouraged by planned updates to the IWG process, including additional public comment and peer review on the estimates, while also reserving judgment until further details are provided on the approach of the peer review. The commenter argues the agency's decision to include the External Review Draft in this rulemaking has now sowed confusion among interested parties about whether this represents an official update to the IWG SC-GHG, raises concerns as to the cohesiveness of the IWG, could potentially lead to delays in finalizing and implementing any final methane regulations, and hinders the credibility of the External Review Draft. The commenter argues that EPA's decision to release the External Review Draft independent of the IWG "may set a new precedent, whereby each agency under the IWG's umbrella will publish its own SC-GHG estimates, which would defeat the entire purpose of the uniform IWG process and foster nothing but continuing regulatory uncertainty." To remedy these concerns, the commenter recommends that EPA withdraw the External Review Draft and defer to the IWG for updating SC-GHG estimates under E.O. 13990.

Response A-7-5: EPA disagrees with the commenters' contention that it is procedurally improper for the Agency to develop updated SC-GHG estimates for use in RIA analysis. As an initial matter, commenters rely on an executive order that by its own terms creates no right or benefit enforceable against the U.S. government by any party. *See* E.O. 13990 sec. 8(c).

EPA is a member of the Interagency Working Group (IWG) that was reconstituted in 2021 under Executive Order (E.O.) 13990 and is in the process of developing a comprehensive update of its recommended SC-GHG estimates. In February 2021, the IWG recommended the interim use of the most recent SC-GHG estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation (IWG 2021). As discussed in the February 2021 TSD<sup>275</sup>, the IWG

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<sup>275</sup> Interagency Working Group on Social Cost of Carbon (IWG). 2021 (February). *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990*. United States

concluded that these interim estimates reflected the immediate need to have SC-GHG estimates available for agencies to use in regulatory benefit-cost analyses and other applications until updated estimates that address the National Academies' recommendations are available. The IWG's February 2021 TSD recognized the limitations of the interim estimates and encouraged agencies to use their best judgment in, for example, considering lower discount rates.

The EPA is committed to making evidence-based decisions pertaining to the methodologies used in EPA analyses, guided by the best available science and input from the public and peer reviewers. Thus, as noted in previous EPA regulatory impact analyses and the Proposal RIA and Supplemental Proposal RIA for this action, while the EPA is participating in the IWG's work under E.O. 13990, the Agency is also continuously reviewing developments in the scientific literature, including more robust methodologies for estimating the magnitude of the various direct and indirect damages from GHG emissions, and looking for opportunities to further improve SC-GHG estimation going forward. EPA's development of updated SC-GHG estimates, and use of these estimates in sensitivity analysis in an RIA along with an external peer review and public comment process, is similar to the process by which SC-CH<sub>4</sub> estimates were first used in EPA RIAs. As explained in the SC-GHG Report, the EPA began using estimates of SC-CH<sub>4</sub> and SC-N<sub>2</sub>O from Marten et al. (2015)<sup>276</sup> in RIAs starting in 2015. The Marten et al. estimates were first applied in sensitivity analyses in RIAs of proposed rulemakings with CH<sub>4</sub> and N<sub>2</sub>O emission impacts.<sup>277</sup> Following the completion of an external peer review of the application of these estimates to federal regulatory analysis, the estimates were used in the main analysis of other rulemakings with CH<sub>4</sub> emissions impacts (see EPA 2015a<sup>278</sup>, 2015b<sup>279</sup>, 2016a<sup>280</sup>, 2016b<sup>281</sup>, and EPA and DOT (2016)<sup>282</sup> for a discussion of public comments received on the valuation of non-CO<sub>2</sub> GHG impacts in general and the use of the Marten et al. (2015) estimates). In August 2016, the IWG folded these SC-CH<sub>4</sub> and SC-N<sub>2</sub>O estimates into their SC-GHG

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Government. [https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument\\_SocialCostofCarbonMethaneNitrousOxide.pdf](https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf)

<sup>276</sup> Marten, A. L., Kopits, E. A., Griffiths, C. W., Newbold, S. C., and Wolverton, A., 2015. Incremental CH<sub>4</sub> and N<sub>2</sub>O mitigation benefits consistent with the US Government's SC-CO<sub>2</sub> estimates. *Climate Policy* 15(2), pp.272–298.

<sup>277</sup> The SC-CH<sub>4</sub> and SC-N<sub>2</sub>O estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2 (EPA and DOT 2015).

<sup>278</sup> U.S. Environmental Protection Agency (EPA), 2015a. Regulatory Impact Analysis for the Proposed Revisions to the Emission Guidelines for Existing Sources and Supplemental Proposed New Source Performance Standards in the Municipal Solid Waste Landfills Sector. August. <https://www.regulations.gov/document?D=EPA-HQ-OAR-2014-0451-0086>

<sup>279</sup> U.S. Environmental Protection Agency (EPA), 2015b. Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector. EPA-452/R-15-002. August. <https://www.regulations.gov/document/EPA-HQ-OAR-2010-0505-5258>

<sup>280</sup> U.S. Environmental Protection Agency (EPA), 2016a. Regulatory Impact Analysis of the Final Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. EPA-452/R-16-002. [https://www.epa.gov/sites/default/files/2020-07/documents/oilgas\\_ria\\_nsps\\_final\\_2016-05.pdf](https://www.epa.gov/sites/default/files/2020-07/documents/oilgas_ria_nsps_final_2016-05.pdf)

<sup>281</sup> U.S. Environmental Protection Agency (EPA), 2016b. Regulatory Impact Analysis for the Final Revisions to the Emission Guidelines for Existing Sources and the Final New Source Performance Standards in the Municipal Solid Waste Landfills Sector. EPA-452/R-16-003. [https://www3.epa.gov/ttnecas1/docs/ria/landfills\\_ria\\_final-eg-nsps\\_2016-07.pdf](https://www3.epa.gov/ttnecas1/docs/ria/landfills_ria_final-eg-nsps_2016-07.pdf)

<sup>282</sup> U.S. Environmental Protection Agency (EPA) and U.S. Department of Transportation (DOT), 2016. Regulatory Impact Analysis of the Final Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2. EPA-420-R-16-900. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100P7NS.PDF?Dockey=P100P7NS.PDF>

recommendations to agencies within an addendum to the IWG's TSD (IWG 2016a<sup>283</sup>, 2016b<sup>284</sup>). EPA's updated SC-GHG estimates and accompanying report will be among the many technical inputs available to the IWG as it continues its work.

The EPA disagrees that EPA's release of updated SC-GHG estimates within an EPA RIA will create regulatory uncertainty for industry and other stakeholders. As described above, the EPA provides notice and public comment opportunities on each proposed regulation and its accompanying analyses, including any use of the SC-GHG in benefit-cost analyses. Thus, regulated entities and other interested stakeholders can anticipate having the standard opportunities for public comment on any proposed rule for which any SC-GHG estimates are applied in an analysis either accompanying or supporting such rulemaking. In this instance, commenters, including those here, had the opportunity to comment on all aspects of the data and methodologies that inform the presentation of the SC-GHG values in the final RIA accompanying this action.

Comment: Commenters (2301-U.S. Chamber of Commerce, 2361-EPRI) criticize the EPA peer review process of its External Review Draft and argue that this process was insufficient.

Commenter (2361-EPRI) suggests that EPA's proposed peer review and overall scientific process is insufficient to develop scientifically robust and reliable estimates and insufficient for the public to have confidence in the outcome. The commenter suggests that EPA implement the following changes: (1) Revise the peer review candidate selection process to ensure full and unbiased coverage of the core scientific disciplines underpinning the SC-GHG, (2) Expand the peer review process to a scientific review process, (3) Submit the External Review Draft to a peer review panel of at least 14 appropriate panelists, including two experts per relevant core scientific discipline, (4) Conduct a peer review appropriate for regulatory methodology, which should seek to provide the public with confidence in the outcome, (5) Substantially increase opportunities for public engagement and input, and (6) Improve the overall scientific process for developing and using SC-GHG estimates. The commenter highlights a recent EPRI article that discusses the importance of these suggestions, particularly pertaining to appropriate peer review.<sup>285</sup> Specifically, the commenter suggests that EPA explicitly requests a peer review of the scientific reliability and robustness of the methodology and estimates, selects an appropriate peer review panel to carry out the review, requires consensus recommendations from the review panel, provides a transparent process with public input regarding the panel selection, and to revise the panel selection criteria for the needed core science expertise while avoiding conflicts of interests and following all existing peer review guidance.

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<sup>283</sup> Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2016a (August). *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under 12866*. United States Government. [https://www.epa.gov/sites/default/files/2016-12/documents/sc\\_co2\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf)

<sup>284</sup> Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). 2016b (August). *Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide*. United States Government. [https://www.epa.gov/sites/default/files/2016-12/documents/addendum\\_to\\_sc-ghg\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf)

<sup>285</sup> Rose, S, 2022. Putting science first in creating and using the social cost of carbon, The Hill, November 18, [thehill.com](https://thehill.com)



Commenter (2301-U.S. Chamber of Commerce) states that as EPA appeared to be taking lead in organizing the peer review process of the IWG's updated SC-GHG estimates on behalf of the IWG and the agencies, it was assumed that further iterations of the SC-GHG estimates would be published for peer review by the IWG directly under a separate OMB docket. The commenter adds that by releasing the External Review Draft as an appendix to the Methane Proposal, EPA has limited the public's awareness of this draft largely to those potentially subject to any finalized methane regulations, despite the fact that SC-GHG estimates will have a much broader impact. The commenter expresses concern that including the External Review Draft unnecessarily opens the Methane Proposal up to additional risk of legal challenges that could delay its implementation.

Response A-7-6: The EPA believes that conducting a transparent, high-quality external peer review of the updated SC-GHG estimates is important to ensure that the methodological updates adopted in EPA's SC-GHG Report are consistent with economic theory and reflect the latest science. The EPA disagrees with the commenters' assertions that the peer review of the SC-GHG Report was insufficient or that the process was unclear. EPA conducted the peer review of the draft SC-GHG Report consistent with the guidelines set forth in EPA's Peer Review Handbook 4th Edition, 2015.<sup>286</sup>

The peer review was independently managed by a contractor to EPA. The contractor reviewed the public nominations received in response to a 21-day call for peer reviewer nominations that ended on February 15, 2022 [federalregister.gov/d/2022-01387] to ensure they have the types of disciplinary expertise listed in the notice and used traditional techniques (e.g., a literature search) to identify additional qualified candidates in the disciplines described below. The contractor then developed a list of 14 candidate reviewers. EPA invited public comment on all 14 candidates. The 21-day comment period closed December 1, 2022. After review and consideration of public comments received on the candidates, the contractor selected the final panel of 7 experts in a manner consistent with EPA's Peer Review Handbook 4th Edition, 2015 (EPA/100/B-15/001), based on the following factors: (1) Demonstrated expertise through relevant peer-reviewed publications in one or more of the following areas: environmental economics, climate science, integrated assessment modeling, and benefit-cost analysis; (2) professional accomplishments and recognition by professional societies; (3) demonstrated ability to work constructively and effectively in a committee setting; (4) absence of conflicts of interest; (5) no appearance of partiality; (6) willingness to commit adequate time for a thorough review of the draft report, including preparation of individual written comments that will be made publicly available; and (7) availability to participate virtually in a public peer review meeting and to provide subsequent revised individual comments. The contractor then independently conducted a conflict of interest (COI) screening of the candidates and final selected reviewers to confirm that those listed have no COI in conducting this review. The contractor ensured that the peer reviewers did not participate in the development of the product being reviewed and are independent of EPA as required under OMB's Final Information Quality Guidelines for Peer Review (p. 38).

In addition to the two opportunities for comment during the peer review selection process as described above, the public was also invited to attend the meeting of the peer review panel on

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<sup>286</sup> [https://www.epa.gov/sites/default/files/2020-08/documents/epa\\_peer\\_review\\_handbook\\_4th\\_edition.pdf](https://www.epa.gov/sites/default/files/2020-08/documents/epa_peer_review_handbook_4th_edition.pdf)

March 29, 2023. The EPA posted the charge questions on the EPA webpage and provided public notice of the peer reviewer meeting 3 weeks in advance. Since the public comment period on the Supplemental Proposal closed on February 13, 2023, the public comments received on the Supplemental Proposal were also available to the peer reviewers as they conducted their review. Some peer reviewers even cited public comments in their final report. The EPA posted a recording of the public meeting on the webpage and posted the final peer review report following its completion in May 2023.

The peer reviewers commended the agency on its development of this update, calling it a much-needed improvement in estimating the SC-GHG and a significant step towards addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates have been incorporated into the SC-GHG Report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the charge questions and final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available at: <https://www.epa.gov/environmental-economics/scghg-td-peer-review>.

## Appendix B. List of Mass Campaigns/Form Letters

### B.1 Volume I - List of Mass Campaigns/Form Letters on the Proposed Rule (86 FR 63110)

| No. | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                     | Duplicate Count* |
|-----|-------------------------------------------|----------------------------------------------------------------------------------------------|------------------|
| 1.  | <a href="#">EPA-HQ-OAR-2021-0317-0609</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                 | 99               |
| 2.  | <a href="#">EPA-HQ-OAR-2021-0317-0969</a> | Mass Comment Campaign sponsored by Earthworks. (web) (Part 1 of 2)                           | 5999             |
| 3.  | <a href="#">EPA-HQ-OAR-2021-0317-0970</a> | Mass Comment Campaign sponsored by Earthworks. (web) (Part 2 of 2)                           | 5423             |
| 4.  | <a href="#">EPA-HQ-OAR-2021-0317-0971</a> | Mass Comment Campaign sponsored by Green America. (web)                                      | 166566           |
| 5.  | <a href="#">EPA-HQ-OAR-2021-0317-0972</a> | Mass Comment Campaign sponsored by Clean Water Action. (web)                                 | 36               |
| 6.  | <a href="#">EPA-HQ-OAR-2021-0317-0973</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 375              |
| 7.  | <a href="#">EPA-HQ-OAR-2021-0317-0974</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 45               |
| 8.  | <a href="#">EPA-HQ-OAR-2021-0317-0975</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 135              |
| 9.  | <a href="#">EPA-HQ-OAR-2021-0317-0976</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 735              |
| 10. | <a href="#">EPA-HQ-OAR-2021-0317-0977</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 334              |
| 11. | <a href="#">EPA-HQ-OAR-2021-0317-0978</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 21               |
| 12. | <a href="#">EPA-HQ-OAR-2021-0317-0979</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 524              |
| 13. | <a href="#">EPA-HQ-OAR-2021-0317-0980</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 215              |
| 14. | <a href="#">EPA-HQ-OAR-2021-0317-0981</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 59               |
| 15. | <a href="#">EPA-HQ-OAR-2021-0317-0982</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 42               |
| 16. | <a href="#">EPA-HQ-OAR-2021-0317-0983</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 65               |

| No. | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                           | Duplicate Count* |
|-----|-------------------------------------------|----------------------------------------------------------------------------------------------------|------------------|
| 17. | <a href="#">EPA-HQ-OAR-2021-0317-0984</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 22               |
| 18. | <a href="#">EPA-HQ-OAR-2021-0317-0985</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 148              |
| 19. | <a href="#">EPA-HQ-OAR-2021-0317-0986</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 20               |
| 20. | <a href="#">EPA-HQ-OAR-2021-0317-0987</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 88               |
| 21. | <a href="#">EPA-HQ-OAR-2021-0317-0988</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 205              |
| 22. | <a href="#">EPA-HQ-OAR-2021-0317-0989</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 43               |
| 23. | <a href="#">EPA-HQ-OAR-2021-0317-0990</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 117              |
| 24. | <a href="#">EPA-HQ-OAR-2021-0317-0991</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)       | 130              |
| 25. | <a href="#">EPA-HQ-OAR-2021-0317-0992</a> | Mass Comment Campaign sponsored by Sierra Club. (web)                                              | 12523            |
| 26. | <a href="#">EPA-HQ-OAR-2021-0317-0993</a> | Mass Comment Campaign sponsored by Sierra Club. (web)                                              | 5137             |
| 27. | <a href="#">EPA-HQ-OAR-2021-0317-0994</a> | Mass Comment Campaign sponsored by Environment America, U.S. PIRG, and Environmental Action. (web) | 32046            |
| 28. | <a href="#">EPA-HQ-OAR-2021-0317-0995</a> | Mass Comment Campaign by public representatives from the Commonwealth of Pennsylvania. (web)       | 59               |
| 29. | <a href="#">EPA-HQ-OAR-2021-0317-0996</a> | Mass Comment Campaign sponsored by a Conservation Voters New Mexico. (web)                         | 628              |
| 30. | <a href="#">EPA-HQ-OAR-2021-0317-0997</a> | Mass Comment Campaign sponsored by Northern Plains Resource Council. (web)                         | 306              |
| 31. | <a href="#">EPA-HQ-OAR-2021-0317-0998</a> | Mass Comment Campaign sponsored by 198 methods. (web)                                              | 4690             |
| 32. | <a href="#">EPA-HQ-OAR-2021-0317-0999</a> | Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC). (web)                 | 24534            |
| 33. | <a href="#">EPA-HQ-OAR-2021-0317-1000</a> | Mass Comment Campaign sponsored by Earthworks. (web)                                               | 150              |
| 34. | <a href="#">EPA-HQ-OAR-2021-0317-1001</a> | Mass Comment Campaign sponsored by Clean Air Council. (web)                                        | 41               |
| 35. | <a href="#">EPA-HQ-OAR-2021-0317-1002</a> | Mass Comment Campaign sponsored by Western Organization of Resource Councils. (web)                | 477              |

| No. | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                            | Duplicate Count* |
|-----|-------------------------------------------|-----------------------------------------------------------------------------------------------------|------------------|
| 36. | <a href="#">EPA-HQ-OAR-2021-0317-1003</a> | Mass Comment Campaign sponsored by Clean Water Action. (web)                                        | 15               |
| 37. | <a href="#">EPA-HQ-OAR-2021-0317-1004</a> | Mass Comment Campaign sponsored by Clean Water Action. (web)                                        | 207              |
| 38. | <a href="#">EPA-HQ-OAR-2021-0317-1005</a> | Mass Comment Campaign by Community Members in the Permian Basin. (email)                            | 53               |
| 39. | <a href="#">EPA-HQ-OAR-2021-0317-1006</a> | Mass Comment Campaign by Faculty from the University of Texas and Texas AM College Systems. (email) | 46               |
| 40. | <a href="#">EPA-HQ-OAR-2021-0317-1007</a> | Mass Comment Campaign sponsored by 350 Silicon Valley and 350 Seattle. (web)                        | 688              |
| 41. | <a href="#">EPA-HQ-OAR-2021-0317-1008</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                        | 12354            |
| 42. | <a href="#">EPA-HQ-OAR-2021-0317-1009</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                        | 3042             |
| 43. | <a href="#">EPA-HQ-OAR-2021-0317-1010</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                        | 4040             |
| 44. | <a href="#">EPA-HQ-OAR-2021-0317-1011</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                        | 57               |
| 45. | <a href="#">EPA-HQ-OAR-2021-0317-1012</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                        | 47               |
| 46. | <a href="#">EPA-HQ-OAR-2021-0317-1013</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 7                |
| 47. | <a href="#">EPA-HQ-OAR-2021-0317-1014</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 58               |
| 48. | <a href="#">EPA-HQ-OAR-2021-0317-1015</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 176              |
| 49. | <a href="#">EPA-HQ-OAR-2021-0317-1016</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 427              |
| 50. | <a href="#">EPA-HQ-OAR-2021-0317-1017</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 94               |
| 51. | <a href="#">EPA-HQ-OAR-2021-0317-1351</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 162              |
| 52. | <a href="#">EPA-HQ-OAR-2021-0317-1352</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 371              |
| 53. | <a href="#">EPA-HQ-OAR-2021-0317-1353</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 375              |
| 54. | <a href="#">EPA-HQ-OAR-2021-0317-1354</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)        | 261              |

| No. | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                              | Duplicate Count* |
|-----|-------------------------------------------|-------------------------------------------------------------------------------------------------------|------------------|
| 55. | <a href="#">EPA-HQ-OAR-2021-0317-1355</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 794              |
| 56. | <a href="#">EPA-HQ-OAR-2021-0317-1356</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 58               |
| 57. | <a href="#">EPA-HQ-OAR-2021-0317-1357</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 89               |
| 58. | <a href="#">EPA-HQ-OAR-2021-0317-1358</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 9                |
| 59. | <a href="#">EPA-HQ-OAR-2021-0317-1359</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 45               |
| 60. | <a href="#">EPA-HQ-OAR-2021-0317-1360</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)          | 50               |
| 61. | <a href="#">EPA-HQ-OAR-2021-0317-1361</a> | Mass Comment Campaign sponsored by American Lung Association. (web)                                   | 329              |
| 62. | <a href="#">EPA-HQ-OAR-2021-0317-1362</a> | Mass Comment Campaign sponsored by American Lung Association. (web)                                   | 503              |
| 63. | <a href="#">EPA-HQ-OAR-2021-0317-1363</a> | Mass Comment Campaign sponsored by American Lung Association. (web)                                   | 361              |
| 64. | <a href="#">EPA-HQ-OAR-2021-0317-1364</a> | Mass Comment Campaign sponsored by Western Leaders Network. (email)                                   | 168              |
| 65. | <a href="#">EPA-HQ-OAR-2021-0317-1365</a> | Mass Comment Campaign sponsoring organization unknown. (paper)                                        | 32               |
| 66. | <a href="#">EPA-HQ-OAR-2021-0317-1392</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                          | 11110            |
| 67. | <a href="#">EPA-HQ-OAR-2021-0317-1393</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                        | 9641             |
| 68. | <a href="#">EPA-HQ-OAR-2021-0317-1394</a> | Mass Comment Campaign submitted by member of Moms Clean Air Force. Sample attached (email)            | 2709             |
| 69. | <a href="#">EPA-HQ-OAR-2021-0317-1395</a> | Mass Comment Campaign by members of Group Against Smog and Pollution (GASP). Sample attached. (email) | 22               |
| 70. | <a href="#">EPA-HQ-OAR-2021-0317-1396</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                        | 36               |
| 71. | <a href="#">EPA-HQ-OAR-2021-0317-1397</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                        | 6164             |
| 72. | <a href="#">EPA-HQ-OAR-2021-0317-1398</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                        | 84               |
| 73. | <a href="#">EPA-HQ-OAR-2021-0317-1399</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                        | 7                |

| No. | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                     | Duplicate Count* |
|-----|-------------------------------------------|----------------------------------------------------------------------------------------------|------------------|
| 74. | <a href="#">EPA-HQ-OAR-2021-0317-1400</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 734              |
| 75. | <a href="#">EPA-HQ-OAR-2021-0317-1401</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 70               |
| 76. | <a href="#">EPA-HQ-OAR-2021-0317-1402</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 10710            |
| 77. | <a href="#">EPA-HQ-OAR-2021-0317-1403</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 1201             |
| 78. | <a href="#">EPA-HQ-OAR-2021-0317-1404</a> | Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web) | 6347             |
| 79. | <a href="#">EPA-HQ-OAR-2021-0317-1431</a> | Mass Comment Campaign sponsored by Evangelical Environmental Network (EEN) (paper)           | 133242           |
| 80. | <a href="#">EPA-HQ-OAR-2021-0317-1435</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 64               |
| 81. | <a href="#">EPA-HQ-OAR-2021-0317-1436</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 10               |
| 82. | <a href="#">EPA-HQ-OAR-2021-0317-1437</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 73               |
| 83. | <a href="#">EPA-HQ-OAR-2021-0317-1438</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 429              |
| 84. | <a href="#">EPA-HQ-OAR-2021-0317-1439</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 626              |
| 85. | <a href="#">EPA-HQ-OAR-2021-0317-1440</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 35               |
| 86. | <a href="#">EPA-HQ-OAR-2021-0317-1454</a> | Mass Mail Campaign sponsored by GreenLatinos. Sample attached (email)                        | 88               |
| 87. | <a href="#">EPA-HQ-OAR-2021-0317-1455</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)               | 111              |
| 88. | <a href="#">EPA-HQ-OAR-2021-0317-1456</a> | Mass Comment Campaign sponsored by GreenLatinos (email)                                      | 87               |
| 89. | <a href="#">EPA-HQ-OAR-2021-0317-1457</a> | Mass Comment Campaign sponsored by GreenLatinos (email)                                      | 74               |
|     |                                           | <b>TOTAL NO.</b>                                                                             | <b>470629</b>    |

\*Number of duplicate submissions.

## B.2 Volume II - List of Mass Campaigns/Form Letters on the Supplemental Proposal (87 FR 74702)

| No. Order | Document ID (linked)                      | Commenter Name, Organization/Affiliation                                                      | Mass Mailer Count |
|-----------|-------------------------------------------|-----------------------------------------------------------------------------------------------|-------------------|
| 1.        | <a href="#">EPA-HQ-OAR-2021-0317-1610</a> | Mass Comment Campaign sponsored by Senior Stewards Acting for the Environment (SSAFE) (email) | 298               |
| 2.        | <a href="#">EPA-HQ-OAR-2021-0317-2021</a> | Mass Comment Campaign sponsored by Arc Initiatives. (email)                                   | 8383              |
| 3.        | <a href="#">EPA-HQ-OAR-2021-0317-2155</a> | Mass Comment Campaign sponsored by ARC Initiatives. (email)                                   | 14510             |
| 4.        | <a href="#">EPA-HQ-OAR-2021-0317-2216</a> | Mass Comment Campaign sponsored by Arizona Interfaith Power & Light. (web)                    | 91                |
| 5.        | <a href="#">EPA-HQ-OAR-2021-0317-2467</a> | Mass Comment Campaign sponsored by ARC Initiatives. (email)                                   | 12974             |
| 6.        | <a href="#">EPA-HQ-OAR-2021-0317-2468</a> | Mass Comment Campaign sponsored by Northern Plains Resource Council. (email)                  | 260               |
| 7.        | <a href="#">EPA-HQ-OAR-2021-0317-2469</a> | Mass Comment Campaign sponsored by Western Organization of Resource Councils (WORC). (email)  | 261               |
| 8.        | <a href="#">EPA-HQ-OAR-2021-0317-2470</a> | Mass Comment Campaign sponsored by League of Conservation Voters (LCV). (email)               | 162               |
| 9.        | <a href="#">EPA-HQ-OAR-2021-0317-2471</a> | Mass Comment Campaign sponsored by Clean Air Council. (email)                                 | 45                |
| 10.       | <a href="#">EPA-HQ-OAR-2021-0317-2472</a> | Mass Comment Campaign sponsored by Clean Air Council. (email)                                 | 17                |
| 11.       | <a href="#">EPA-HQ-OAR-2021-0317-2473</a> | Mass Comment Campaign sponsored by Clean Air Council. (email)                                 | 18                |
| 12.       | <a href="#">EPA-HQ-OAR-2021-0317-2474</a> | Mass Comment Campaign sponsoring organization unknown. (email)                                | 29                |
| 13.       | <a href="#">EPA-HQ-OAR-2021-0317-2475</a> | Mass Comment Campaign sponsored by EarthWorks                                                 | 36836             |
| 14.       | <a href="#">EPA-HQ-OAR-2021-0317-2476</a> | Mass Comment Campaign sponsored by Climate Action Campaign. (web)                             | 858               |
| 15.       | <a href="#">EPA-HQ-OAR-2021-0317-2477</a> | Mass Comment Campaign sponsored by Evangelical Environmental Network (EEN). (web) (part 1)    | 61999             |
| 16.       | <a href="#">EPA-HQ-OAR-2021-0317-2478</a> | Mass Comment Campaign submitted by National Religious Partnership for the Environment. (web)  | 13516             |
| 17.       | <a href="#">EPA-HQ-OAR-2021-0317-2479</a> | Mass Comment Campaign sponsored by Natural Resources Defense Council (NRDC). (web)            | 20608             |
| 18.       | <a href="#">EPA-HQ-OAR-2021-0317-2480</a> | Mass Comment Campaign sponsored by Climate Action Campaign. (web)                             | 321               |
| 19.       | <a href="#">EPA-HQ-OAR-2021-0317-2481</a> | Mass Comment Campaign sponsored by Climate Action Campaign. (web)                             | 3876              |
| 20.       | <a href="#">EPA-HQ-OAR-2021-0317-2482</a> | Mass Comment Campaign sponsored by Climate Reality Project. (web)                             | 15021             |
| 21.       | <a href="#">EPA-HQ-OAR-2021-0317-2484</a> | Mass Comment Campaign sponsored by American Lung Association (ALA) et al. (web)               | 69                |
| 22.       | <a href="#">EPA-HQ-OAR-2021-0317-2485</a> | Mass Comment Campaign sponsored by American Lung Association (ALA). (web)                     | 291               |
| 23.       | <a href="#">EPA-HQ-OAR-2021-0317-2486</a> | Mass Comment Campaign sponsored by American Lung Association (ALA). (web)                     | 705               |
| 24.       | <a href="#">EPA-HQ-OAR-2021-0317-2487</a> | Mass Comment Campaign sponsored by American Lung Association (ALA). (web)                     | 19                |



| <b>No.<br/>Order</b> | <b>Document ID (linked)</b>               | <b>Commenter Name, Organization/Affiliation</b>                                                   | <b>Mass<br/>Mailer<br/>Count</b> |
|----------------------|-------------------------------------------|---------------------------------------------------------------------------------------------------|----------------------------------|
| 25.                  | <a href="#">EPA-HQ-OAR-2021-0317-2488</a> | Mass Comment Campaign sponsored by Environment America, U.S. PIRG and Environmental Action. (web) | 42280                            |
| 26.                  | <a href="#">EPA-HQ-OAR-2021-0317-2489</a> | Mass Comment Campaign sponsored by Sierra Club. (web)                                             | 9579                             |
| 27.                  | <a href="#">EPA-HQ-OAR-2021-0317-2490</a> | Mass Comment Campaign sponsored by Mom Clean Air Force, AZ, et al. (web)                          | 43                               |
| 28.                  | <a href="#">EPA-HQ-OAR-2021-0317-2491</a> | Mass Comment Campaign sponsored by Defend Our Future. (web)                                       | 862                              |
| 29.                  | <a href="#">EPA-HQ-OAR-2021-0317-2492</a> | Mass Comment Campaign sponsored by Environment Texas Research and Policy Center. (web)            | 231                              |
| 30.                  | <a href="#">EPA-HQ-OAR-2021-0317-2493</a> | Mass Comment Campaign sponsored by PennEnvironment Research and Policy Center. (web)              | 156                              |
| 31.                  | <a href="#">EPA-HQ-OAR-2021-0317-2494</a> | Mass Comment Campaign sponsored by Green America. (web)                                           | 15552                            |
| 32.                  | <a href="#">EPA-HQ-OAR-2021-0317-2495</a> | Mass Comment Campaign submitted by Climate Action Campaign. (web)                                 | 34                               |
| 33.                  | <a href="#">EPA-HQ-OAR-2021-0317-2496</a> | Mass Comment Campaign sponsored by Evangelical Environmental Network (EEN). (web) (part 2)        | 41434                            |
| 34.                  | <a href="#">EPA-HQ-OAR-2021-0317-2497</a> | Mass Comment Campaign submitted by Appalachian Leaders Network. (web)                             | 87                               |
| 35.                  | <a href="#">EPA-HQ-OAR-2021-0317-2733</a> | Mass Comment Campaign sponsored by MoveOn Federal Affairs. (email)                                | 2,662                            |
| 36.                  | <a href="#">EPA-HQ-OAR-2021-0317-2734</a> | Mass Comment Campaign sponsored by MoveOn Federal Affairs. (email)                                | 3,173                            |
| 37.                  | <a href="#">EPA-HQ-OAR-2021-0317-2735</a> | Mass Comment Campaign sponsored by Union of Concerned Scientists et al. (web)                     | 392                              |
| 38.                  | <a href="#">EPA-HQ-OAR-2021-0317-2768</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 2046                             |
| 39.                  | <a href="#">EPA-HQ-OAR-2021-0317-2769</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 6759                             |
| 40.                  | <a href="#">EPA-HQ-OAR-2021-0317-2770</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 918                              |
| 41.                  | <a href="#">EPA-HQ-OAR-2021-0317-2771</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 149                              |
| 42.                  | <a href="#">EPA-HQ-OAR-2021-0317-2772</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 27483                            |
| 43.                  | <a href="#">EPA-HQ-OAR-2021-0317-2773</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 19                               |
| 44.                  | <a href="#">EPA-HQ-OAR-2021-0317-2774</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 24885                            |
| 45.                  | <a href="#">EPA-HQ-OAR-2021-0317-2775</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 97                               |
| 46.                  | <a href="#">EPA-HQ-OAR-2021-0317-2776</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 89                               |
| 47.                  | <a href="#">EPA-HQ-OAR-2021-0317-2777</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 9057                             |
| 48.                  | <a href="#">EPA-HQ-OAR-2021-0317-2778</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 105                              |
| 49.                  | <a href="#">EPA-HQ-OAR-2021-0317-2779</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 33                               |
| 50.                  | <a href="#">EPA-HQ-OAR-2021-0317-2780</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                    | 3665                             |

| <b>No.<br/>Order</b> | <b>Document ID (linked)</b>               | <b>Commenter Name, Organization/Affiliation</b>                                                    | <b>Mass<br/>Mailer<br/>Count</b> |
|----------------------|-------------------------------------------|----------------------------------------------------------------------------------------------------|----------------------------------|
| 51.                  | <a href="#">EPA-HQ-OAR-2021-0317-2781</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 31                               |
| 52.                  | <a href="#">EPA-HQ-OAR-2021-0317-2782</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 1259                             |
| 53.                  | <a href="#">EPA-HQ-OAR-2021-0317-2783</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 6952                             |
| 54.                  | <a href="#">EPA-HQ-OAR-2021-0317-2784</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 7                                |
| 55.                  | <a href="#">EPA-HQ-OAR-2021-0317-2785</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 17                               |
| 56.                  | <a href="#">EPA-HQ-OAR-2021-0317-2786</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 508                              |
| 57.                  | <a href="#">EPA-HQ-OAR-2021-0317-2787</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (email)                     | 1240                             |
| 58.                  | <a href="#">EPA-HQ-OAR-2021-0317-2858</a> | Mass Comment Campaign sponsored by members of League of Conservation Voters. Sample attached (web) | 23641                            |
| 59.                  | <a href="#">EPA-HQ-OAR-2021-0317-2859</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 11182                            |
| 60.                  | <a href="#">EPA-HQ-OAR-2021-0317-2860</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 18373                            |
| 61.                  | <a href="#">EPA-HQ-OAR-2021-0317-2861</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 462                              |
| 62.                  | <a href="#">EPA-HQ-OAR-2021-0317-2862</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 750                              |
| 63.                  | <a href="#">EPA-HQ-OAR-2021-0317-2863</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 232                              |
| 64.                  | <a href="#">EPA-HQ-OAR-2021-0317-2864</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 79                               |
| 65.                  | <a href="#">EPA-HQ-OAR-2021-0317-2865</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 11                               |
| 66.                  | <a href="#">EPA-HQ-OAR-2021-0317-2866</a> | Mass Comment Campaign sponsored by members of League of Conservation Voters. Sample attached (web) | 8                                |
| 67.                  | <a href="#">EPA-HQ-OAR-2021-0317-2867</a> | Mass Comment Campaign sponsored by members of League of Conservation Voters. Sample attached (web) | 3393                             |
| 68.                  | <a href="#">EPA-HQ-OAR-2021-0317-2868</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 8672                             |
| 69.                  | <a href="#">EPA-HQ-OAR-2021-0317-2869</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 2899                             |
| 70.                  | <a href="#">EPA-HQ-OAR-2021-0317-2870</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 95                               |
| 71.                  | <a href="#">EPA-HQ-OAR-2021-0317-2871</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 23                               |
| 72.                  | <a href="#">EPA-HQ-OAR-2021-0317-2872</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 31                               |
| 73.                  | <a href="#">EPA-HQ-OAR-2021-0317-2873</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web) SPANISH version       | 124                              |
| 74.                  | <a href="#">EPA-HQ-OAR-2021-0317-2874</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 304                              |
| 75.                  | <a href="#">EPA-HQ-OAR-2021-0317-2875</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 11657                            |
| 76.                  | <a href="#">EPA-HQ-OAR-2021-0317-2876</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 5831                             |

| <b>No.<br/>Order</b> | <b>Document ID (linked)</b>               | <b>Commenter Name, Organization/Affiliation</b>                                                    | <b>Mass<br/>Mailer<br/>Count</b> |
|----------------------|-------------------------------------------|----------------------------------------------------------------------------------------------------|----------------------------------|
| 77.                  | <a href="#">EPA-HQ-OAR-2021-0317-2877</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 19                               |
| 78.                  | <a href="#">EPA-HQ-OAR-2021-0317-2878</a> | Mass Comment Campaign sponsored by members of League of Conservation Voters. Sample attached (web) | 3727                             |
| 79.                  | <a href="#">EPA-HQ-OAR-2021-0317-2879</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 26734                            |
| 80.                  | <a href="#">EPA-HQ-OAR-2021-0317-2880</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 2232                             |
| 81.                  | <a href="#">EPA-HQ-OAR-2021-0317-2881</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 61                               |
| 82.                  | <a href="#">EPA-HQ-OAR-2021-0317-2882</a> | Mass Comment Campaign sponsoring organization unknown. Sample attached (web)                       | 17                               |
| 83.                  | <a href="#">EPA-HQ-OAR-2021-0317-3815</a> | Mass Comment Campaign sponsored by Interfaith Power and Light. (paper)                             | 779                              |
|                      |                                           | <b>TOTAL</b>                                                                                       | <b>514,307</b>                   |

\*Number of duplicate submissions

## **Appendix C. Examples of Mass Campaigns/Form Letters**

### **C.1 Volume I - Examples of Mass Campaigns/Form Letters on the Proposed Rule (86 FR 63110)**

**MAILER SECTOR:** Academia

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-1006](#)

**COMMENTS NAME:** Mass Comment Campaign by Faculty from the University of Texas and Texas AM College Systems. (email)

In the U.S. oil and gas production is the largest industrial source of methane pollution. This pollution is accelerating the pace of climate change and harming the health of our families and communities — and it's only getting worse.

This issue hits close to home. The University of Texas is the fifth-largest oil producer in the state, with 10,000 oil wells in West Texas on land owned by the University. Unfortunately, these wells have been shown to consistently release harmful methane into the atmosphere with little regulation - in 2017, these wells flared as much as 5.2 billion cubic feet of natural gas. Despite University of Texas researchers publishing a number of studies on the dangers of flaring, and UT representatives speaking out against methane flaring, University Lands has failed to implement any substantial solutions. We now call upon the EPA to make certain that its potential new guidelines protect people and the planet from these toxic releases.

While EPA's proposed methane safeguards are an important step in the right direction, they do not go far enough, and must be strengthened in order to protect communities on the frontlines of oil and gas development, and confront the climate crisis head-on. The EPA must strengthen their proposed rule to protect public health and the climate, through a supplemental rulemaking or other action, in order to:

1. End the wasteful and dangerous practice of routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already.
2. Require regular monitoring at all smaller, high-polluting and leak-prone wells, and
3. Work to incorporate emission monitoring results generated by community groups and other third parties into its standards.

We cannot miss out on this opportunity to cut methane pollution, safeguard public health, and act on climate. That means strengthening your proposed rules to finalize the most comprehensive methane safeguards that finally reign in methane waste from oil and gas companies and hold polluters accountable.

**MAILER SECTOR: Non-profit, Public Health & Environmental Advocacy Group**  
**DOCKET NO.: [EPA-HQ-OAR-2021-0317-0992](#)**  
**COMMENTS NAME: Mass Comment Campaign sponsored by Sierra Club. (web)**

Dear EPA Administrator Michael Regan,

I applaud the EPA for taking action to curb oil and gas methane pollution on behalf of the 12.5 million people living in our country who live near oil and gas drilling operations and all of us who face impacts from climate change. I specifically support federal methane standards for existing equipment and requiring zero-emitting pneumatic controllers at all new and existing sites. Thank you for also improving on the Obama Administration's oil and gas standards by, for example, including emission reduction requirements for liquids unloading events, regulating methane at storage tanks, and increasing the frequency of leak monitoring at many oil and gas wells.

However, I believe the EPA must go even further by increasing mandatory leak inspections to monthly for all wells and compressor stations and by eliminating the exemption from regular monitoring from those for wells that are calculated to emit below three tons per year of methane. We urge the EPA to further study advanced LDAR monitoring as one way of increasing the scope of its monitoring requirements.

In addition, flaring is a major nuisance and source of pollution for local communities near oil and gas operations. It must also be strictly limited so that operators can no longer flare associated gas at oil wells on a routine basis. I also urge the EPA to propose standards for abandoned or orphaned wells that require owners and operators to plug and control emissions from these sources, which are responsible for huge amounts of uncontrolled pollution.

Finally, I strongly support the EPA creating a community monitoring program. People who live near oil and gas operations are already documenting flaring, leaks, and other pollution that directly harms them. I support the EPA studying the relevant legal and technical considerations in order to establish an effective program where third-parties, citizen groups, and others could identify leaking equipment so as to ensure rapid repairs.

Thank you for the opportunity to comment.

**MAILER SECTOR: Non-profit, Public Health & Environmental Advocacy Group**  
**DOCKET NO.: [EPA-HQ-OAR-2021-0317-0996](#)**  
**COMMENTS NAME: Mass Comment Campaign sponsored by a Conservation Voters**  
**New Mexico. (web)**

We submitted our own organizational comment earlier today. Attached please find the petition we sent to members asking for their sign on. In just over a week, we received 631 signatures. New Mexico's own methane rules are divided between the Oil Conservation Commission, which already approved stringent rules on waste from venting and flaring, and the Environmental Improvement Board, which will announce its decision on leaks of ozone precursors later this year. Combined, the two rules make New Mexico a national leader in reducing methane emissions, an issue important to our members, many of whom live in the two major oil and gas basins in the state: the San Juan Basin in the northwest and the Permian Basin in the southeast and who regularly report their health impacts and the damage to the air, land and water in their region.

**MAILER SECTOR: Non-profit, Public Health & Environmental Advocacy Group**  
**DOCKET NO.: [EPA-HQ-OAR-2021-0317-1361](#)**  
**COMMENTS NAME: Mass Comment Campaign sponsored by American Lung**  
**Association. (web)**

Dear Administrator Regan:

As physicians, nurses, public health professionals and healthcare workers dedicated to providing our patients with a healthy future, we urge you to finalize comprehensive, loophole-free methane safeguards.

We thank the U.S. Environmental Protection Agency (EPA) for recognizing the threats posed by pollution from the oil and gas industry, and for proposing a rule to cut methane and other harmful pollutants from new and existing oil and gas operations. We urge EPA to strengthen and finalize the proposal into law without delay.

Climate change is a health emergency, and methane - a significant component of what is often referred to as "natural" gas - is a powerful climate pollutant. Methane is a dangerous greenhouse gas. Eighty-six times more potent than carbon dioxide, it is making our planet warmer, and public health is being harmed. To avoid catastrophic tipping points in the climate system, we must reduce greenhouse gases, including methane, dramatically and immediately. A recent report from the Lancet Medical Journal highlighted that without aggressive action to slash greenhouse gas pollution, the climate crisis will become the "defining narrative of human health." The proposed rule is a vital step forward in addressing these health threats, but must go further.

Stronger final rules will not only curb greenhouse gases, they will also result in immediate public health benefits by reducing volatile organic compounds, or VOCs. Some VOCs can cause cancer, affect the nervous system, or cause birth defects. In addition to being toxic, VOCs contribute to the formation of ground-level ozone pollution, which causes respiratory and cardiovascular harm, heart attacks and asthma attacks, stroke and early death. Ozone is also linked to premature birth, which with low birth weight is a leading cause of infant death. Communities living near oil and gas operations are especially at risk from these toxic emissions, and strong final standards are crucial to protect them.

We urge you to strengthen the proposed rule to reduce methane pollution from new and existing oil and gas operations by 65 percent of 2012 levels by 2025. This is an achievable target, and one that can be met using existing technologies, at low cost. We also urge you to strengthen requirements for smaller, low-producing wells require more frequent leak detection monitoring and repair; and put an end to the practice of routine flaring (burning of waste gas that results in harmful air pollution.) Requiring the oil and gas industry to take the most effective steps possible to prevent fugitive emissions of methane and other gases, and to capture those gases that do escape, will reduce climate pollution and result in direct health benefits in communities near oil and gas operations.

We urge EPA to strengthen and then quickly finalize requirements for new, reconstructed and modified oil and gas wells and equipment and standards for existing sources.

**MAILER SECTOR: Non-profit, Public Health & Environmental Advocacy Group**

**DOCKET NO.: [EPA-HQ-OAR-2021-0317-1394](#)**

**COMMENTS NAME: Mass Comment Campaign submitted by member of Moms Clean Air Force. Sample attached (email)**

As a parent and member of Moms Clean Air Force, I'm deeply concerned with the health impacts of air pollution and climate change. That's why I was encouraged to learn that the EPA has proposed rules to cut methane and other harmful air pollutants from new and existing oil and gas operations.

This is an important first step to address the impacts of methane pollution. That's why I urge you to ensure that these rules are strong and comprehensive. They must cover all sources of oil and gas operations including smaller, leak-prone wells and limit routine flaring, both of which are outsized sources of methane emissions. Quickly and significantly reducing methane pollution is one of the best levers we have to slow the rate of climate change now, and it will help clean up the air to protect children's health.

Federal methane rules will establish vital protections for all children across the nation, especially for states that have failed to enact meaningful oil and gas methane protections at the state level.



Please ensure that the EPA passes comprehensive methane rules to protect our children's health and future.

**MAILER SECTOR: Other Advocacy Group**

**DOCKET NO.: [EPA-HQ-OAR-2021-0317-0973](#)**

**COMMENTS NAME: Mass Comment Campaign sponsored by National Religious Partnership for the Environment. (web)**

Dear Administrator Regan:

The proposed rules by the Environmental Protection Agency are an important step forward in undercutting the harms of methane pollution and addressing climate change. These standards can help protect communities, especially black communities, which are hit hard by climate change and air pollution.

With more than 1 million African-Americans living within a half-mile of an existing natural gas facility, methane pollution leaves these communities exposed to toxic air pollution, with negative health impacts including cancer, reproductive and respiratory problems.

These rules rightly regulate the oil and natural gas sector, the largest industrial source of methane, which is a potent climate pollutant 80 times more powerful than carbon dioxide. Reducing methane pollution can moderate the near-term impacts of climate change, which disproportionately affect low-wealth communities and communities of color. In study after study communities of color have been shown to disproportionately bear the burden of climate impacts. In the US, people of color have been found to be more vulnerable to heatwaves and extreme weather events, exasperating the systemic racism that is already suffered.

As Christians, we are called to care for God's creation and our communities, particularly the most vulnerable such as children, low-income families, and communities of color. Issuing national standards on methane will help care for these communities, including black communities, by protecting them from methane pollution and curbing climate change.

As Black Church leaders and lay leaders in Ohio, we the EPA to make methane pollution safeguards strong and work to protect all communities and in particular black communities.



**MAILER SECTOR: Other Advocacy Group**

**DOCKET NO.: [EPA-HQ-OAR-2021-0317-1431](#)**

**COMMENTS NAME: Mass Comment Campaign sponsored by Evangelical Environmental Network (EEN) (paper)**

Dear Administrator Regan:

On behalf of 133,242 pro-life Christians, I am honored to submit their supportive comments to the Environmental Protection Agency regarding the referenced proposed regulations.

*As pro-life Christians, we want the air we breathe to be safe for our children. But leaks in our oil/gas infrastructure spew toxic pollutants that put God's creation and our families - pregnant mothers and the unborn - in harm's way. Unborn children close to leaks are at higher risk of birth defects, and children attending school near leaks have higher rates of cancer and asthma.*

*That's why Christians are calling on the EPA to ensure that stronger regulations and inspections will cut this pollution from both existing and new leaks, particularly from low-producing wells. Our kids deserve better.*

We are thankful for EPA's proposed rules that will defend children's health. We are especially thankful that the new proposed standards are based on actual methane emissions instead of the amount of oil and gas production. Recent studies clearly prove that many smaller, leak-prone wells have disproportionately high emission rates of methane and associated gases.<sup>i</sup> Under the new emission-based rule, these methane superemitters will no longer slip through the cracks. Combined, the two standards will save \$6.6 - \$9.2 billion in avoided health costs and loss of life. While this indeed is good news, the proposed standards in the rule would be strengthened by incorporating the following:

- A ban on routine flaring except in emergency situations.
- Quarterly inspection via LDAR (Leak Detection and Repair) procedures of all wells with 2 tons per year (tpy) of methane emissions or greater. **(This recommendation is based on EPA's own conclusion in the proposed rule, which states: "...sites with total baseline methane emissions of 2 tpy, we conclude that regular monitoring at semiannual or quarterly frequencies would be cost-effective.")** Based on this conclusion that quarterly inspection of well sites with 2tpy emissions is cost-effective, we recommend that the 3-tpy-emissions threshold in the currently proposed standard be reduced to 2tpy-emissions and that the frequency of inspections be increased to quarterly.
- Sites below 2 tpy emission need to be inspected at least annually.
- Require a time limit on the need to replace all pneumatic valves and actuators.
- Develop a process for the incorporation of monitoring data from third-parties. The expanded monitoring may result in a major public health benefit.

- We look forward to secondary proposal due in Spring 2022 and hope that new methodologies for monitoring are approved and incorporated.

In the U.S., oil and gas production is the largest industrial source of methane pollution. Each year, the oil and gas industry releases 16 million metric tons of methane, and without immediate action, methane pollution from the industry will continue to skyrocket. We urge the EPA to promulgate these standards in the most expeditious fashion to defend our children and their future.

Footnote:

<sup>i</sup> Zavala-Araiza, et al., (2015) “Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites,” Environ. Sci. Technol. 2015, 49, 13, at 8167–8174 (“Zavala-Araiza [2015]”)

**MAILER SECTOR: State Government**

**DOCKET NO.: [EPA-HQ-OAR-2021-0317-0995](#)**

**COMMENTS NAME: Mass Comment Campaign by public representatives from the Commonwealth of Pennsylvania. (web)**

On behalf of the undersigned 59 public representatives from the Commonwealth of Pennsylvania, we write to you today in support of strong and comprehensive requirements to cut methane pollution from oil and gas operations. As the second largest producer of natural gas in the nation, and with significant numbers of both old and new well sites and infrastructure, our state is a prime example of why these strong standards are critical.

Methane, the principal component of natural gas, is over 80 times more potent than carbon dioxide over a 20-year time period. Recent studies found U.S. methane emissions levels to be 60% greater than currently estimated by the Environmental Protection Agency (EPA). Strange and severe weather events accelerated by climate change are already costing Pennsylvanians hundreds of millions of dollars, left people homeless, and flooded farmland.

In addition to methane, smog-forming volatile organic compounds (VOCs) and toxic hazardous air pollutants (HAPs), including cancer-causing agents such as benzene, are released by oil and gas operations. Smog is associated with 1.1 million summertime asthma attacks in children. This pollution contributes to the smog challenges across the state, especially in major metropolitan areas.

As elected officials, we are critically aware of the importance of protecting public health – both from a broader climate concern as well as considering local air quality and pollution impacts to our constituents and communities. This is a problem facing every resident of our state but especially frontline communities that must live with the oil and gas infrastructure and activity on a daily basis. The need for meaningful and inclusive standards is acute across Pennsylvania and

the benefits that can be achieved by strong rules that go far beyond emission reductions to real dollars that can be measured in the improved health of our children, families, friends, and neighbors.

We commend the EPA for proposing a rulemaking to reduce methane emissions at existing sites and facilities, as well as your consideration of a supplemental rulemaking to address leak detection and repair for smaller, leak-prone well sites. These well sites are found throughout our state, and their numbers are growing each and every year. It's important to note that low-producing wells are responsible for almost half of the methane pollution from oil and gas sources in Pennsylvania, or over half a million tons annually. According to the University of Cincinnati's Amy Townsend-Small, Ph.D., many wells that produce less than a barrel of oil per day leak into the atmosphere more than 100 percent of their reported gas production.

We appreciate the agency requiring an initial inspection but absent regular and frequent inspection requirements, these wells pose a considerable threat that – unless addressed fundamentally undermines the goals of this proposed rulemaking.

Thankfully, we have common sense solutions to reduce emissions that are cost-effective and will put people to work to find and fix leaks. Plus, reducing methane means less energy waste and more revenue to offset costs. That is a win for our environment and our economy.

We urge you to expeditiously develop and finalize comprehensive rules that cover all oil and gas well sites.

**MAILER SECTOR: Unknown Sponsoring Organization**

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-1008](#)

**COMMENTS NAME:** Mass Comment Campaign sponsoring organization unknown.  
**Sample attached (web)**

I am writing in support of the EPA's proposed methane standard and to ask that the EPA take stronger action to reduce methane pollution. Over 12.5 million Americans live near enough to oil and gas drilling to be at risk for its health impacts, and methane is a major contributor to global warming as it is 86 times more potent of a greenhouse gas than carbon dioxide. Addressing Methane pollution is also an environmental justice issue. Oil and gas pollution disproportionately affects people of color, who have higher rates of health conditions associated with gas wells.

The long-overdue methane standards for existing oil and gas operations will help protect the health of communities harmed by oil and gas pollution and reduce the impact of methane pollution on climate change. Other provisions, including regulating methane from storage tanks and more frequent monitoring for methane leaks, will similarly have significant positive impacts on health and climate.

While we applaud the EPA for taking these important steps to regulate methane, the new rule does not go far enough to reduce methane pollution and allows for significant gaps in regulating emissions that will continue to expose people living near gas wells to severe health risks.

I urge the EPA to take stronger steps to reduce methane pollution by doing the following:

- Require monthly leak inspections at all wells and compressor stations and eliminate exemptions for smaller, high-polluting and leak-prone wells, including for wells that produce less than three tons per year of emissions.
- End routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already. Flaring is dangerous, wastes natural resources, and creates pollution that harms health and climate.
- Create a community monitoring program and incorporate community monitoring into the methane standard.
- Create standards for abandoned or orphaned wells that require owners and operators to plug and control emissions from these sources, which are responsible for huge amounts of uncontrolled pollution.

Strengthening the proposed methane rule is essential to protecting the health of communities suffering the impacts of oil and gas pollution and achieving the U.S.'s climate goals.

**MAILER SECTOR: Unknown Sponsoring Organization**

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-1392](#)

**COMMENTS NAME:** Mass Comment Campaign sponsoring organization unknown.  
**Sample attached (web)**

As a person of faith and conscience, I am writing to thank you for the recent rules on methane pollution from the oil and gas industry. The rules as proposed are an excellent start, but this critical moment of the climate crisis demands we do as much as possible immediately.

I am asking EPA to strengthen the proposed rule to end the wasteful and dangerous practice of routine flaring at oil and gas operations, as states like Colorado and New Mexico have done already. As I understand it, flareless completion is a reasonable alternative that may not even increase costs significantly.

([https://earthworks.org/issues/flareless\\_completions/#sthash.YKyufYb6.dpuf](https://earthworks.org/issues/flareless_completions/#sthash.YKyufYb6.dpuf))

I also ask EPA to require regular monitoring at all smaller, high-polluting and leak-prone wells.

All faith traditions share a sacred calling to care for the earth and to care for those who are most vulnerable in our communities. As a Unitarian Universalist minister, I lead a community with a deep commitment to respecting the interdependent web of which we are all a part. As a trained climate economist, I understand that our current practice of excessive emissions give us short-

term gains with a completely unaffordable long-term price tag.

Methane pollution causes deep and irreparable harm, polluting not only the land and the air, but also jeopardizing the health of children and those living in frontline communities.

Methane is a potent greenhouse gas and it's responsible for a quarter of the warming that we are experiencing today. We know that far too much is leaking from oil and gas operations and contributing to the climate crisis while wasting this resource and endangering public health. Our EPA must implement rules that will cut methane pollution from oil and gas operations 65 percent by 2025 while eliminating any loopholes around flaring and smaller wells that can contribute outsized methane pollution.

It is EPA's obligation and moral opportunity to protect all Americans from harmful methane pollution.

Thank you.

**MAILER SECTOR: Unknown Sponsoring Organization**

**DOCKET NO.: [EPA-HQ-OAR-2021-0317-1402](#)**

**COMMENTS NAME: Mass Comment Campaign sponsoring organization unknown.**

**Sample attached (web)**

Methane pollution is threatening our communities and wildlife by driving climate change.

In the U.S., oil and gas production is the largest industrial source of methane pollution. This pollution is accelerating the pace of climate change and harming the health of our families and cherished wildlife — and it's only getting worse. Thanks to the Environmental Protection Agency's new proposed rule, we now have an opportunity to restore regulations that rein in methane pollution.

The rule promises to cut methane emissions by 41 million tons. Because methane acts as a super-pollutant in the near-term, these reductions will help buy the U.S. time to continue working to solve the climate crisis and protect people and wildlife from unavoidable impacts. The rule also will reduce volatile organic compound (VOC) emissions by 12 million tons and hazardous air pollution by 480,000 tons, which will help prevent lung disease and asthma, smog, and premature death.

While EPA's proposed methane safeguards are an important step in the right direction, they do not go far enough, and must be strengthened in order to protect communities on the frontlines of oil and gas development, and confront the climate crisis head-on. EPA must strengthen their proposed rule to protect public health and the climate, through a supplemental rulemaking or other action, in order to:

1. End the wasteful and dangerous practice of routine flaring at oil and gas facilities, as states like Colorado and New Mexico have done already.
2. Require regular monitoring at all smaller, high-polluting and leak-prone wells, and work to incorporate emission monitoring results generated by community groups and other third parties into its standards.

We cannot miss out on this opportunity to cut methane pollution, safeguard public health and wildlife, and act on climate. That means strengthening the agency's proposed rules to finalize the most comprehensive methane safeguards that finally rein in methane emissions from oil and gas operations.

Thank you for your consideration.

## **C.2 Volume II - Examples of Mass Campaigns/Form Letters on the Supplemental Proposal (87 FR 74702)**

**MAILER SECTOR:** Other/Other Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2155](#)

**COMMENTS NAME:** Mass Comment Campaign sponsored by ARC Initiatives. (email)

Methane pollution from the oil and gas sector is accelerating the pace of climate change and harming the health of our families and communities across the country. That is why we are counting on the Environmental Protection Agency (EPA) to quickly finalize the strongest possible safeguards to cut methane and other harmful pollution from the oil and gas industry.

The updated draft rule improves upon or maintained many of the standards in the original draft rule released by EPA in 2021 identified by climate, public health, and environmental justice advocates like me, including by ensuring all wells are regularly and frequently inspected for leaks and that outdated pneumatic equipment is replaced with zero-emitting options. But there is more work to be done to ensure that communities like mine are protected.

EPA must do more to ensure that:

- Operators at wells capture associated gas and limit flaring of that gas in instances in which it is necessary for safety or maintenance reasons;
- Strengthen the standards to address emissions from storage tanks by making the standards applicable to more tanks; and
- Provide a clear pathway for participation in the Super Emitter Response Program by ensuring communities and citizens can access data and technologies to help reduce methane and other pollutants in the areas where we live and work.

My community is counting on your agency to quickly address these concerns, and to finalize strong, comprehensive new and existing source rules to cut methane pollution from the oil and gas sector before it's too late.

Thank you for your consideration.

**MAILER SECTOR:** Non-profit, Public Health & Environmental Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2477](#)

**COMMENTS NAME:** Mass Comment Campaign sponsored by Evangelical Environmental Network (EEN). (web) (part 1)

As pro-life Christians, we want the air we breathe to be safe for our children. But leaks in our oil/gas infrastructure spew toxic pollutants that put God's creation and our families - pregnant mothers and the unborn - in harm's way. Unborn children close to leaks are at higher risk of birth defects, and children attending school near leaks have higher rates of cancer and asthma.

That's why Christians are calling on the EPA to ensure that stronger regulations and inspections included in EPA's Methane Supplemental Rule are never weakened. We want maximum protection for our children from pollution, particularly from low-producing wells.

We also call on EPA to make the rule stronger by:

- Limiting flaring except as needed for safety or maintenance.
- Including all storage tanks in the standard to reduce the leaks.
- Providing a clear way for communities to monitor and report large leaks from the oil and gas industry.

**MAILER SECTOR:** Non-profit, Public Health & Environmental Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2484](#)

**COMMENTS NAME:** Mass Comment Campaign sponsored by American Lung Association (ALA) et al. (web)

Dear Administrator Regan:

As representatives of regional, state and local health organizations and societies committed to patient care and public health, we support strong protections against environmental health harms. The U.S. Environmental Protection Agency (EPA) proposal to limit pollution from oil and gas operations is necessary to mitigate the immediate and long-term health risks resulting from the extraction, transportation and storage of oil and gas. We thank EPA for the updates made to the original proposal and urge the quick finalization of a strong rule no later than August 2023.

Protecting health, for our patients as well as practitioners and caregivers, is our top priority. But there is only so much that we and the institutions and constituents we represent can do at an individual level to protect health from outdoor air pollution. Enforceable rules to limit leaking of toxic air pollutants and climate pollutants like methane will immediately benefit public health in communities across the country and help stave off catastrophic effects of climate change.

Methane is a highly potent greenhouse gas that is accelerating climate change. Climate change poses threats to the ability of health professionals to help the public and deliver life sustaining care. It also increases the number of people who seek medical care or assistance by lengthening



allergy seasons, increasing vector borne illnesses and making air pollution worse. To truly realize a healthier future for all, we must drastically reduce the emissions that are perpetuating climate change.

A strong rule will also reduce the emissions of harmful pollutants that are released alongside methane at oil and gas sites. Volatile organic compounds (VOCs) include gases identified as hazardous air pollutants such as benzene, toluene and formaldehyde, among others. Benzene and formaldehyde are known human carcinogens. Ethylbenzene, another hazardous pollutant from oil and gas emissions, is a probable carcinogen. In addition to these dangers, VOCs also interact with other emissions in the presence of sunlight to form ground-level ozone pollution. Ozone, or smog, can worsen asthma, increase hospital visits, and contribute to low-birth weight (a leading cause of infant death) and premature death.

The updates made in this supplemental proposal strengthen the rule from EPA's original proposal in some areas – including advanced leak detection and repair standards, requiring zero emission pneumatic controllers and pumps and requiring the cleanup of more abandoned wells. We urge EPA to strengthen the proposal further by requiring operators of oil wells to better protect public health by limiting routine flaring of associated gas to safety or maintenance episodes. We also ask that EPA ensure the Super Emitter Response Program, which is designed to identify and address large leaks, includes clear and accessible pathways for communities and individuals to engage in holding polluters accountable.

As health organizations, we recognize the dangers of air and climate pollution and the benefits that will be experienced by all if the nation takes significant steps to reduce emissions and lessen the use of fossil fuels. This proposal by EPA to limit pollution from the oil and gas sector is needed to provide relief to communities that have been overburdened by dangerous pollution. We urge EPA to finalize the strongest possible rule by no later than August 2023.

**MAILER SECTOR:** Non-profit, Public Health & Environmental Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2488](https://www.epa.gov/epaospr/docket-0317-2488)

**COMMENTS NAME:** Mass Comment Campaign sponsored by Environment America, U.S. PIRG and Environmental Action. (web)

I applaud the EPA for proposing an updated methane rule that would curb significant sources of methane emissions. Still, the current draft of the rule contains loopholes that could allow unmitigated releases of methane to continue, especially through the practice of routine flaring and venting of methane directly into the atmosphere.

In November 2021, President Biden signed onto the Global Methane Pledge to reduce world methane emissions 30% below 2020 levels by 2030. That's a great first step toward healthier air and a more stable climate -- but we risk falling short if we don't address methane flaring and other practices that vent this pollutant directly into the atmosphere.

I urge you to make the final methane rule as strong as possible by including restrictions that phase out pollution from routine flaring.

**MAILER SECTOR:** Non-profit, Public Health & Environmental Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2492](#)

**COMMENTS NAME:** Mass Comment Campaign sponsored by Environment Texas Research and Policy Center. (web)

I support the proposed new protections aimed at cutting methane emissions, which is one of the worst global warming pollutants on the planet, in the oil and gas industry. The proposed safeguards would help reduce harmful air pollution, protecting both our climate, and our health. Although the proposal is strong, there are still improvements to be made. I urge the EPA to enact the strongest possible safeguards against methane pollution.

**MAILER SECTOR:** Non-profit, Public Health & Environmental Advocacy Group

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2493](#)

**COMMENTS NAME:** Mass Comment Campaign sponsored by PennEnvironment Research and Policy Center. (web)

We, the undersigned, thank you for proposing strong air pollution standards for new and existing gas and oil infrastructure.

We appreciate that the proposed rule will help curb dangerous climate-warming emissions, reduce the release of pollutants known to worsen asthma and other respiratory diseases, and limit harmful smog pollution.

We are also extremely supportive of the fact that the proposal requires inspections at small wells that often have leak-prone equipment as well as the requirement that abandoned wells are subject to inspections until proper closure. These requirements will help protect the health of the more than a million Pennsylvanians living near wells sites.

We also appreciate the steps taken towards addressing super-emitters through a third-party monitoring program.

At the same time, we urge the U.S. Environmental Protection Agency to strengthen the rules by phasing out pollution from routine venting and flaring. We encourage you to push for the strongest possible methane rule to protect our health, tackle climate change, and build a safer and stronger commonwealth.

**MAILER SECTOR:** Unknown

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2772](#)

**COMMENTS NAME:** Mass Comment Campaign sponsoring organization unknown. Sample attached (email)

Cutting methane pollution from the oil and gas industry is the quickest, most cost-effective way to slow the rate of climate change happening now and protect community and wildlife health. That is why I support the Environmental Protection Agency's (EPA) proposed updated rule to cut methane and other harmful pollutants from oil and gas operations across the country. My community has waited too long for bold action to cut methane, and we need these protections now more than ever.

Reducing methane emissions is of the utmost importance for wildlife that continue to be negatively impacted by oil and gas development that fragments their habitat and puts additional strain on threatened species through accelerating climate change.

Cutting methane pollution will also have profound effects on millions of people across the U.S. experiencing record heat. Slowing today's unprecedented rate of warming can help avert our most acute climate risks, including megafires and extreme weather. New oil and gas sector pollution limits will also help prevent greater suffering from severe health impacts caused by smog and exposure to cancer-causing toxic emissions, a particular threat to communities of color and those living near facilities.

Now, the EPA must move quickly to enact solutions for pollution and finalize the strongest possible safeguards—such as eliminating pollution from flaring, requiring regular monitoring at smaller wells with leak-prone equipment, instituting community monitoring, and requiring zero-emitting pneumatic controllers and pumps.

Every day that passes without strong federal methane rules is a missed opportunity to reduce climate and air pollution from the oil and gas industry and protect the health and well-being of communities and wildlife across this country. We cannot continue to wait. We need the Biden administration to use all of its authority to enact strong solutions for pollution that protect our health, advance justice, and fight climate change.

**MAILER SECTOR:** Unknown

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2879](#)

**COMMENTS NAME:** Mass Comment Campaign sponsoring organization unknown. Sample attached (web)

Dear Environmental Protection Agency,

Earlier this month, environmental justice advocates and public health experts from around the country participated in a nationwide day of action to call on President Biden to cut methane pollution from the oil and gas industry.

This effort follows a proposal from EPA that would lead to a moderate reduction in methane leaks. The Biden administration has the chance to go further, but that's only going to happen if they hear from us now.

Oil and gas development has plagued vulnerable communities with methane pollution that pollutes the air, leaving residents at higher risk of cancer, asthma, and birth defects.

President Biden and EPA must strengthen new safeguards to further reduce methane pollution from the oil and gas industry, protect public health, and address the climate crisis. Half-measures won't do enough to protect frontline communities - the federal government must do more.

**MAILER SECTOR:** State / Local Government

**DOCKET NO.:** [EPA-HQ-OAR-2021-0317-2497](#)

**COMMENTS NAME:** Mass Comment Campaign submitted by Appalachian Leaders Network. (web)

As local and state elected officials from across Pennsylvania, Ohio and West Virginia, including the Appalachian region, we write today to support the proposed Environmental Protection Agency regulations to reduce methane pollution and waste from new and existing oil and gas operations and to support key measures to strengthen the standards before they become final.

As elected officials who collectively represent tens of thousands of constituents, we understand firsthand how important this issue is to our communities. For generations, Appalachia has been one of the largest producers of natural gas in our country, and with significant numbers of both old and new well infrastructure, our region will benefit substantially from reduced methane emissions.

Methane, which has more than 80 times the warming power of carbon dioxide over its first 20 years in the atmosphere, is released alongside dangerous pollution such as cancer-causing volatile organic compounds (VOCs) and air toxics like benzene. VOCs can also [worsen asthma and respiratory disease](#) and cause immune system damage and developmental problems in young

children. Methane also contributes to ground-level ozone, also known as smog, which worsens air quality and presents health risks across the state, especially in major metropolitan areas.

The oil and gas industry is one of the leading sources of methane pollution in the U.S., emitting roughly 16 million metric tons of methane every year. Pollution from small wells is an outsized problem too. In fact, while low-producing wells account for just 6% of production nationwide, these wells are responsible for 50% of methane emissions at oil and gas well sites. Here in Appalachia, these wells emit 1.2 million tons of methane annually.

In the Appalachian region, large percentages of the total population live within one mile of oil and gas wells. In West Virginia, more than half of the state's residents live near active wells (50.9%), the highest percentage in the nation, while more than a quarter (25.9%) of Ohioans and almost fifteen (15%) percent of Pennsylvanians.

Cutting methane pollution and waste from the oil and gas industry is the [quickest, most cost-effective way](#) to slow the rate of climate change happening now and protect communities and the environment from the worst effects of climate-forced extreme weather events.

The proposed rule is a significant step forward in achieving this goal, and we thank you for your steadfast leadership on this issue. Specifically, the updated draft rule improves upon the 2021 proposal by:

- Closing a loophole in the leak detection and repair (LDAR) standards. This change would require inspections with optical gas imaging cameras at all wells with equipment known to malfunction, such as tanks and flares.
- Moving away from the EPA's existing production-based LDAR requirements would require routine leak inspections at all wells, including low-producing wells that are responsible for half of all methane emissions nationwide.
- Strengthening the requirements for zero-emitting oil and gas equipment by including both pneumatic pumps and controllers.
- Creating a program to more quickly address super-emitters through third-party monitoring.
- Including inspections at abandoned wells until they are properly closed and ensuring that oil and gas companies submit a closure plan and conduct a post-closure survey of these wells to ensure they are not leaking.

However, there are three clear ways these protections must be strengthened:

- Limit flaring to instances where it is necessary for safety or maintenance reasons and require operators at wells to capture associated gas.
- Strengthen emission thresholds on storage tanks.

- Ensure that all communities and individuals can participate in the Super Emitter Response Program by providing a clear pathway for engagement and ensuring that approved monitoring technologies and data are accessible to all.

These issues must be addressed to protect communities affected by oil and gas operations, stop the needless waste of energy resources, and build a healthier, more resilient climate.

We look forward to working with you and your agency to speedily finalize these important standards and get them over the finish line to protect our climate, public health, and local economies.